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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

NICK MYERS, Chair
RACHEL WALDEN, Vice-Chair
LEA MÁRQUEZ PETERSON
KEVIN THOMPSON
RENÉ LOPEZ

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-25-0105 **ARIZONA PUBLIC SERVICE COMPANY'S NOTICE OF FILING REBUTTAL TESTIMONY**

Arizona Public Service Company (APS or Company) provides notice that it is filing the attached rebuttal testimonies of Mr. Theodore N. Geisler, Mr. Jacob Tetlow, Mr. Michael Eugenis, Mr. Kent C. Walter, Mr. Chris R. Bauer, Ms. Elizabeth A. Blankenship,

Ms. Jessica E. Hobbick, Mr. Jamie R. Moe, Mr. James M. Coyne, and Dr. Kimbugwe A. Kateregga.

In addition, pursuant to the Modified Procedural Order issued on July 22, 2025, today APS delivered a USB flash drive to the Hearing Division containing 1) the Company's Power Supply Adjustor (PSA) Plan of Administration schedules, 2) a jurisdictional-only set of SFR schedules updated to reflect the Company's Rebuttal positions, and 3) workpapers supporting the SFR schedules. The files provided via the USB flash drive have also been uploaded to the Company's 2025 Rate Case Extranet Site.

RESPECTFULLY SUBMITTED this 3rd day of April 2026.

By: /s/ Jeffrey S. Allmon
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REBUTTAL TESTIMONY OF THEODORE N. GEISLER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-25-0105

April 3, 2026

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REBUTTAL TESTIMONY OF THEODORE N. GEISLER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-25-0105)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Theodore N. Geisler. I am the Chairman of the Board, Chief Executive Officer (CEO) and President of Pinnacle West Capital Corporation (Pinnacle West) and Chairman of the Board, CEO and President of Arizona Public Service Company (APS or Company), a subsidiary of Pinnacle West. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes. I filed Direct Testimony on June 13, 2025.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rebuttal Testimony is to respond to issues raised in the Utilities Division Staff (Staff) of the Arizona Corporation Commission (Commission) and intervenor testimony that bear on APS's ability to deliver safe, reliable, and affordable service to all customers. I provide context regarding APS's proposed regulatory tools, including the Formula Rate Adjustment Mechanism (FRAM), and explain how these proposals are intended to support timely infrastructure investment, promote rate stability for customers, and maintain rigorous cost-control incentives for the Company. I also discuss recommendations that affect cost recovery for specific expenses, emphasizing the importance of sustaining an appropriate balance between customer and shareholder interests.

I do not address every detail related to Staff and intervenor recommendations, and it should not be interpreted that I agree with any of their positions unless specifically stated in my testimony.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My Rebuttal Testimony reflects APS's commitment to balancing customer and shareholder interests while ensuring we can continue to deliver safe, reliable, and affordable service through periods of unprecedented inflation, population growth, economic expansion, and customer energy demand in our service territory.

I explain that the FRAM is central to the Company's comprehensive "growth pays for growth" strategy, particularly addressing new large, high load factor customers who are driving significant incremental system costs. The FRAM allows costs and rates to remain more closely aligned over time and protects existing customers who are not driving growth from cost shifts. The FRAM also maintains other customer protections and continues the same incentives for APS to control costs subject to Commission oversight as under the current ratemaking process.

I rebut testimony suggesting that APS executives made decisions based on Environmental, Social, and Governance (ESG) considerations or governance preferences rather than system needs, and I explain why that characterization is incorrect. APS's resource, investment, and operational decisions are driven by reliability, affordability, and prudence—not incentive labels or aspirational goals.

Finally, my Rebuttal Testimony addresses cost recovery for a number of prudently incurred expenses that are essential to providing safe, reliable, and affordable electric service. These include Board of Directors expenses, Directors and Officers (D&O) liability insurance, Investor Relations activities, and the employee cash incentive plan. I also explain why the employee pension trust should be treated as

an asset that earns a standard regulated return and benefits customers by enabling the retention of a stable, experienced workforce.

III. FORMULA RATES

Q. PARTIES ASSERT THAT FORMULA RATEMAKING BENEFITS SHAREHOLDERS OVER CUSTOMERS. DO YOU AGREE?

A. No. APS's FRAM proposal is grounded in traditional cost of service ratemaking principles and is designed to modernize—not abandon—those principles. Earnings risk is not eliminated for the Company and shareholders; it is more dependent on the ability to plan and invest prudently, better reflecting today's capital-intensive utility environment.

Contrary to assertions by some intervenors, the formula rate does not weaken cost discipline or reduce customer protections.[1] The mechanism produces smaller, more predictable bill changes through rate gradualism, rather than the larger increases associated with accumulated regulatory lag, and aligns rates more closely with current costs, improving price signals and customer decision making. The formula rate is symmetrical, allowing rates to adjust up or down, ensuring customers benefit when costs decline. It preserves full Commission oversight, stakeholder participation, and prudence review, with annual filings, stakeholder and customer communications, challenge periods, and an earnings test that prevents over-earning, directly addressing concerns that oversight is diminished. APS witnesses Jessica E. Hobbick and Chris R. Bauer discuss the formula rate proposal in more detail in their Direct and Rebuttal Testimonies.

[1] AZLCG, Direct Testimony of Billie S. LaConte (Mar. 2, 2026) (LaConte Direct) at 19; AARP, Direct Testimony of Paul J. Alvarez (Mar. 2, 2026) (Alvarez Direct) at 14, 28; Sierra Club, Direct Testimony of Melissa Whited (Mar. 18, 2026) (Whited Direct) at 28-29; RUCO, Direct Testimony of Cynthia Zwick (Mar. 2, 2026) at 4; RUCO, Direct Testimony of Dustin Madsen, CPA, CDP, CRRA, CPA (CAN), CA (CAN) (Mar. 2, 2026) (Madsen Direct) at 19.

The FRAM is also a key component of APS's "growth pays for growth" strategy with protections that ensure costs associated with new large, high load factor customers, such as data centers, where costs associated with new load are trued-up annually rather than shifted to existing customers. By reducing reliance on frequent, fully litigated general rate cases, the formula rate provides timely cost recovery that supports credit strength and access to capital for needed investments. In doing so, it supports reliability and affordability together, allowing the costs of prudent investments to be recovered steadily over time rather than accumulated and recovered later through larger customer rate adjustments.

Q. DOES THE PROPOSED FRAM ELIMINATE INCENTIVES FOR UTILITIES TO CONTROL COSTS?

A. No. The FRAM maintains significant incentives for APS to control costs—they remain the same regardless of the ratemaking process used under the Commission's regulatory framework. The incentives include:

- **Customer Affordability** – Maintaining affordable rates is essential to meeting customer expectations and sustaining trust. The inclusion of both Customer Affordability and Customer Experience in the Company's performance metrics demonstrates APS's commitment to managing its costs. Customer Affordability measures capital and operations and maintenance (O&M) costs, while Customer Experience uses third-party national benchmarking services to measure the Company's customer satisfaction results, of which price is an attribute. As I outlined in my Direct Testimony, our employees are focused consistently on managing costs to provide our customers with reliable service at the lowest cost possible. As an example, the Company maintained a top-quartile ranking for O&M cost

per customer among 22 United States investor-owned electric utilities during the 12-month period ending December 31, 2024 (Test Year).

- **Regulatory Oversight** – APS remains subject to Commission oversight and must ensure that all expenditures are reasonable and prudent, based on information known at the time of the expenditure, reinforcing disciplined cost management. The FRAM will require more frequent review compared to general rate cases when approving rates to recover these costs. Moreover, the FRAM does nothing to diminish the various planning, auditing, and oversight functions maintained by the Commission prior to the execution of key APS investments or expenditures. This includes processes like Integrated Resource Planning (IRP), the Biennial Transmission Assessment and Ten-Year Transmission Plan, evaluation of APS-owned generation operations under audits of the Power Supply Adjustment (PSA) mechanism, and other processes. More information about these processes is provided by APS witnesses Jacob Tetlow, Michael Eugenis, and Kent C. Walter in their Rebuttal Testimonies.
- **Authorized Return on Equity (ROE) Discipline** – APS manages operating and capital costs in a manner that provides the opportunity to earn its Commission-authorized return, aligning cost control with customer and shareholder interests. The opportunity to achieve earnings growth targets disclosed to investors serves as a natural incentive to control costs, aligning operational efficiency with shareholder expectations. Mr. Bauer discusses these incentives in more detail in his Rebuttal Testimony.
- **Credit Ratings and Access to Capital** – Disciplined cost control contributes to stable financial metrics, which support our existing credit ratings. This enhances APS's ability to access capital and lowers borrowing costs, reducing long-term costs of infrastructure and reliability investments

for customers. Mr. Bauer discusses these incentives in more detail in his Rebuttal Testimony.

- **Stakeholder Accountability** – APS's commitment to transparency, accountability and value reinforces a continued focus on cost efficiency and value that supports constructive engagement with stakeholders.

Based on these cost-control incentives, APS engages in rigorous strategic planning and efficient operations for the effective use of resources. These efforts can produce long-term savings and improved system reliability. Under the proposed FRAM, the Company remains subject to Commission-approved revenue requirements, prudence review, and a defined ROE deadband. The FRAM modernizes the timing of recovery—it does not eliminate cost discipline or regulatory oversight.

Q. PARTIES ASSERT THAT REGULATORY LAG IS A FEATURE OF TRADITIONAL RATEMAKING THAT BENEFITS CUSTOMERS BY INCENTIVIZING UTILITIES TO CONTROL COSTS.[2] DO YOU AGREE?

A. I do not agree. Regulatory lag is not a policy objective or a designed customer protection. It is a byproduct of lengthy regulatory proceedings associated with traditional rate cases. Because regulatory lag results in short-term under-recovery, it also leads to delayed recognition of legitimate costs incurred to serve customers. At the same time, lag also prevents customers from benefiting when conditions enable cost reductions and revenue increases that the FRAM would otherwise reflect as a reduction in rates.

[2] Alvarez Direct at 34-35, 64; Whited Direct at 35-36, 42; LaConte Direct at 19.

Q. PARTIES CLAIM THAT THE FRAM "GUARANTEES" THAT APS WILL ACHIEVE ITS AUTHORIZED RETURN.[3] IS THAT ACCURATE?

A. As I described in my Direct Testimony, the FRAM provides an opportunity to earn the authorized return, but earnings are never guaranteed. The FRAM proposal includes a defined ROE deadband, Commission review and approval of cost and expenses, and continual prudence oversight. Because the FRAM is still based on a historical test year, APS's ability to earn its authorized ROE is directly dependent on a wide range of factors out of APS's control and occurring after the test year. The FRAM simply reduces the time between that historical period and when adjusted rates take effect, mitigating regulatory lag. This is described in more detail by Mr. Bauer and Ms. Hobbick in their Rebuttal Testimonies.

Q. WHAT DOES MICROSOFT CORPORATION (MICROSOFT) FAIL TO RECOGNIZE ABOUT HOW APS'S FRAM PROPOSAL DEALS WITH THE CHALLENGES OF LOAD GROWTH?

A. While Microsoft expresses a willingness to pay their fair share of costs, they dispute APS's methodology.[4] First and foremost, the FRAM is a key part of APS's "growth pays for growth" strategy by enabling annual cost of service evaluations that can be used as the basis for increased cost allocations to those customer classes causing growth related costs. The more frequent adjustments to rates under the FRAM provide more contemporaneous opportunities to directly assign growth related costs to the large, high-load factor customers causing such costs associated with their growth, which protects existing customers from bearing that burden. This

[3] Madsen Direct at 4; Alvarez Direct at 11-13, 28, 70; Whited Direct at 5; LaConte Direct at 8; Western Resource Advocates, Direct Testimony of Ron Nelson (Mar. 18, 2026) at 10, 12.

[4] Microsoft, Direct Testimony of Mark E. Garrett (Mar. 2, 2026) at 5-6.

methodology is described in more detail by APS witnesses Ms. Hobbick and APS witness Jamie R. Moe in their Rebuttal Testimonies.

In addition, and as described in more detail by Mr. Bauer in his Rebuttal Testimony, the FRAM also mitigates regulatory lag and provides key credit support to APS. The credit supportive nature of the FRAM enables greater access to the capital needed to sustain the infrastructure investments APS must make to ensure reliable, affordable service during this period of rapid growth. The FRAM enables greater customer protections and enhances financial stability as APS works to meet the challenges of unprecedented load growth.

IV. LEADERSHIP FOCUS AND SERVICE OBLIGATIONS

Q. WHAT DOES ARIZONA FREE ENTERPRISE CLUB (AZFEC) WITNESS H. STERLING BURNETT, PH.D., ASSERT REGARDING APS'S EXECUTIVE COMPENSATION AND ESG PRINCIPLES?

A. Dr. Burnett asserts that APS's executive compensation, as reflected in Pinnacle West proxy statements from 2021 through 2025, is impacted by ESG principles arising from APS's Clean Energy Commitment.

Q. DO YOU AGREE WITH DR. BURNETT'S CHARACTERIZATION THAT EXECUTIVE COMPENSATION AND ESG PRINCIPLES DROVE APS'S DECISION-MAKING?

A. No. Dr. Burnett's testimony is not supported by the evidence he cites because he assumes that operational decisions are automatically driven by the proxy statement. It is important to understand that proxy statements are disclosure documents describing governance and incentive design at a high level; they do not substitute for, or describe the full substance of, APS's resource planning and procurement processes. Dr. Burnett's inference that compensation design took hold of

decision-making is largely based on generalized statements about ESG frameworks influencing corporate behavior, rather than APS-specific evidence.

Q. WHAT DOES DR. BURNETT MISUNDERSTAND ABOUT THE STRUCTURE OF APS'S "CLEAN MEGAWATTS INSTALLED" PERFORMANCE INCENTIVE?

A. The "clean megawatts installed" metric that Dr. Burnett highlights in his testimony was never intended to function as an incentive for bringing online more renewable and other clean energy generation projects faster than or with greater frequency than what the system needs or APS's resource planning processes would dictate. Instead, it was developed as a project execution metric to incentivize the timely and cost-effective completion of those renewable and other clean energy generation projects otherwise determined to be prudent, based on rigorous planning and competitive solicitations described in further detail in Mr. Eugenis' Rebuttal Testimony. Recognizing changes in market conditions and demonstrated system needs, this metric no longer applies to new incentive grants.

Q. DOES APS AGREE WITH DR. BURNETT'S CONCLUSIONS ON THE IMPACTS OF APS'S CLEAN ENERGY COMMITMENT?

A. No. APS's Clean Energy Commitment did not displace reliability, cost discipline, or prudence considerations.[5] An aspirational, long-term goal does not eliminate or override the obligation to plan and operate a reliable system. Nor does it demonstrate that any specific investment decision was made for ESG reasons rather than to meet system needs.

[5] AZFEC, Direct Testimony of H. Sterling Burnett, PhD (Mar. 2, 2026) (Burnett Direct) at 16.

Q. WHAT HAS CHANGED SINCE APS ADOPTED ITS CLEAN ENERGY COMMITMENT IN 2020?

A. Several foundational assumptions have shifted since 2020. First, the demand for energy has accelerated significantly, driven by population growth, economic development, and large new loads such as advanced manufacturers and data centers. Second, the mix of new customers APS is adding today has shifted to include more large, high load factor users that require new baseload resource additions. Third, the economics of resources have changed, including cost pressures related to market volatility, supply chains, availability of incentives, and integration of new technologies. These changes require us to reassess how quickly and through what mix of resources we pursue to serve customers' unprecedented energy demand while maintaining reliability and affordability.

Q. WHAT IS APS'S RESPONSE TO DR. BURNETT'S ASSERTION ON INCENTIVES BEING TIED TO "CLEAN MEGAWATTS?"

A. APS disagrees with Dr. Burnett's claim that "additional strategic value" equates to improper motivation or imprudent selection.[6] Dr. Burnett offers a theory about how incentives can operate in general. He does not provide evidence that APS gave any weight to "clean" labeling at the expense of reliability, operational performance, or customer value. For example, he does not identify any evidence showing that APS selected the Agave Battery Energy Storage System (BESS) because it qualified for an incentive metric rather than because it met system needs, which it most certainly does.

[6] Burnett Direct at 14.

Q. IS IT ACCURATE TO SAY APS SELECTED THE AGAVE BESS PROJECT BECAUSE IT QUALIFIED AS "CLEAN?"[7]

A. No. As described in more detail by Mr. Tetlow and Mr. Eugenis, the Agave BESS project was procured because it was identified as part of a least-cost, best-fit portfolio of resources following rigorous evaluation as part of APS's All-Source Request for Proposals (ASRFP) process, complements existing thermal and renewable resources, and enhances APS's resource diversity.

V. BALANCING CUSTOMER AND SHAREHOLDER INTERESTS

Q. AARP WITNESS PAUL J. ALVAREZ ASSERTS THAT APS EXECUTIVE LEADERSHIP IS FOCUSED ON SHAREHOLDERS RATHER THAN CUSTOMERS.[8] HOW DO YOU RESPOND?

A. That characterization is inaccurate. As CEO, I am very clear with our employees and shareholders that we must first create customer value through safe, reliable, and affordable service delivery before we can create shareholder value. The suggestion that APS leadership is focused only on shareholders does not reflect how this Company is governed or operated. APS leadership is accountable for reliability, safety, affordability, regulatory compliance, and long-term system planning. As I emphasized in my Direct Testimony, APS is a single state, vertically integrated electric utility, and our leadership team's primary responsibility is to provide safe, reliable, and affordable service to Arizona customers. Every decision we make—whether it involves system reliability, wildfire mitigation, workforce investment, or long-term resource planning—is evaluated first through the lens of customer impact and service obligations. APS's leadership focus includes, but is not limited to, maintaining and upgrading thousands of miles of transmission and distribution infrastructure, preparing the system for extreme heat and wildfire risk,

[7] Burnett Direct at 16.
[8] Alvarez Direct at 5.

serving rapid and sustained customer growth, and ensuring we have a skilled workforce available around the clock. Those responsibilities directly benefit the customers and communities we serve and define how management performance is evaluated.

Q. IS FINANCIAL STABILITY INCONSISTENT WITH CUSTOMER INTERESTS?[9]

A. No. Financial stability is essential to serving customers and is in our customers' best interest. A utility that is financially unstable cannot reliably maintain its system, cannot access capital at reasonable cost, and ultimately exposes customers to higher risk and higher long-term costs. Maintaining financial stability is not about prioritizing shareholders over customers; it is about ensuring APS can continue to provide essential electric service safely, reliably, and affordably over time. Mr. Bauer provides more detail on how APS maintains financial stability and the benefits that it provides to customers.

Q. HOW IS APS EXECUTIVE COMPENSATION STRUCTURED, AND HOW DOES IT RELATE TO CUSTOMER OUTCOMES?

A. Executive compensation at APS is structured around incentives directed at operational performance, safety, reliability, customer experience, customer affordability, regulatory execution, and financial discipline. Financial metrics are part of that framework, and they promote a positive customer experience through cost control, capital efficiency, safe grid operation, and long-term affordability—outcomes that directly benefit customers by supporting reasonable rates and system reliability.

[9] Alvarez Direct at 5.

Q. ARIZONA LARGE CUSTOMER GROUP (AZLCG), RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO), AND FREEPORT MINERALS CORPORATION (FREEPORT) WITNESS COURTNEY M. HIGGINS CHARACTERIZES THE DIFFERENCE BETWEEN THE COMPANY'S RATE BASE AND LOAD GROWTH AS A "SUSTAINED PATTERN."[10] DO YOU AGREE?

A. No. The characterization ignores the changing nature of the Company's electric system and our service obligations. Since filing our previous general rate case, APS has undertaken significant investments to modernize its grid, harden infrastructure, integrate new technologies, and comply with regulatory and policy mandates. These capital investments are driven by a combination of factors, including rising costs of materials, system reliability requirements, aging infrastructure replacement, cybersecurity, wildfire mitigation, compliance with more stringent environmental and safety standards, and the need to maintain adequate capacity to serve peak demand. These investments reflect prudent utility management, not a failure to align capital spending with customer needs.

Q. DOES RATE BASE GROWTH DIRECTLY CORRESPOND WITH RETAIL SALES GROWTH AS MS. HIGGINS CONTENDS?

A. Not necessarily. By focusing narrowly on historical retail sales growth, Ms. Higgins' testimony overlooks the operational, reliability, safety, and policy drivers of APS's investments and understates the benefits those investments provide for

[10] AZLCG, RUCO, and Freeport, Direct Testimony of Courtney M. Higgins (Mar. 2, 2026) (Higgins Direct) at 13.

customers. A comprehensive evaluation must consider the full context of APS's service obligations and the evolving demands placed on the electric system.

Q. DOES APS DISPUTE THAT ITS RATE BASE HAS GROWN FASTER THAN HISTORICAL LOAD OR RETAIL SALES?

A. APS does not dispute the mathematical comparison presented by Ms. Higgins but strongly disagrees with the implication that this comparison demonstrates imprudent investment, unjustified rate pressure, or other cause for concern. Comparing aggregate rate base growth to historical load growth in isolation is an incomplete and misleading way to evaluate the reasonableness of utility investment.

Q. DOES RATE BASE GROWTH NECESSARILY TRANSLATE INTO UPWARD PRESSURE ON RATES?

A. Not necessarily. Rate impacts depend on multiple interacting factors, including depreciation, cost of capital, operating expenses, sales levels (*i.e.*, billing determinants), and the timing of investments. The present rate case filing reflects reasonable efforts to balance necessary infrastructure investment with rate moderation, including the use of regulatory mechanisms that mitigate rate volatility and recognize the long-term benefits of these investments to customers.

Q. HOW DO APS'S INVESTMENTS BENEFIT CUSTOMERS, EVEN IF SALES GROWTH IS MORE MODEST?

A. APS's investments improve reliability, reduce outage risk, enhance grid resiliency, support customer choice, and enable the integration of distributed resources and new technologies. Customers benefit from these investments through improved service quality, reduced long-term risk, improved reliability and resiliency, and

avoidance of higher future costs that would result from deferring necessary infrastructure upgrades.

Q. MS. HIGGINS RECOMMENDS DISALLOWING 50 PERCENT OF INVESTOR RELATIONS EXPENSES.[11] HOW DOES APS RESPOND?

A. APS depends on access to capital markets to fund its daily operations, and Investor Relations activities are essential to gain access to the institutions that provide the required capital. Investor Relations activities support the Company's access to capital markets on reasonable terms, which benefits customers by helping to minimize financing costs associated with utility infrastructure investment. A financially stable utility with efficient capital access is better positioned to provide safe and reliable service at reasonable cost, and APS's Investor Relations function is a foundational component of how such access is maintained.

As Mr. Bauer explains in his Direct Testimony, maintaining credit quality and reliable access to capital is necessary to finance the significant infrastructure investments required to provide safe and reliable service, particularly in periods of market volatility—none of which is possible without Investor Relations.

Q. PLEASE RESPOND TO PARTIES' RECOMMENDATION TO DISALLOW 50 PERCENT OF DIRECTORS & OFFICERS (D&O) LIABILITY INSURANCE AND BOARD OF DIRECTOR FEES.[12]

A. APS accepts the recommendation by Staff, AZLCG, RUCO, and Freeport for a 50/50 allocation between customers and shareholders for both D&O liability insurance and Board of Directors expenses in this case. While these costs are prudently incurred and necessary to operate a large, complex electric utility, the Company's acceptance of a 50 percent allocation strikes a reasonable balance

[11] Higgins Direct at 52.

[12] Staff, Direct Testimony of Ralph C. Smith (Mar. 2, 2026) (Smith Direct) at 69-73; Higgins Direct at 51-53.

between shareholder and customer interests in this case. Accepting these reductions would result in a reduction to our revenue requirement, helping reduce the impact of this necessary rate request on our customers. APS witness Elizabeth A. Blankenship discusses the revenue requirement impacts of these changes in her Rebuttal Testimony.

Q. WHAT BENEFITS DO D&O LIABILITY INSURANCE AND BOARD OF DIRECTOR FEES PROVIDE TO CUSTOMERS?

A. These costs provide substantial and direct benefits to customers. D&O liability insurance and Board of Directors expenses are essential to attracting and retaining highly qualified directors with the experience required to oversee safety, grid security, reliability, financial integrity, regulatory compliance, and long-term system planning. Customers benefit when APS is governed by a Board of Directors and management team capable of navigating complex regulatory requirements, overseeing significant and growing capital investment needs, and ensuring secure and reliable electric service under increasingly challenging operational conditions. These are not abstract benefits—they directly affect service quality, risk management, and long-term costs borne by customers. Board of Director oversight is an integral component of utility management. A substantial portion of the Board of Directors' duties are directly tied to core service functions, such as ensuring compliance with safety, reliability, and regulatory obligations, approving the Company's annual capital budget, reviewing major operating budgets, and advising on risk management activities related to grid operations such as cyber security.

Q. WHY SHOULD THE COST OF THE COMPANY'S CASH INCENTIVE BE RECOVERED IN RATES?

A. APS's employee cash incentive compensation is a necessary cost of providing service. The incentive compensation is based on measurable performance targets,

is prudently incurred, and should be recoverable in rates because it supports customer-focused outcomes and benefits customers. The incentive is a component of total compensation, which is benchmarked to peers in order to attract and retain talent in our industry. Parties including Staff, Freeport, AZLCG, and RUCO contend that because a portion of the APS incentive program is tied to the Company's annual earnings performance, the costs recovered through rates for this program should be reduced by approximately 50 percent.[13]

Neither RUCO, AZLCG, Freeport, nor Staff allege that APS's incentive compensation is excessive, imprudent, or outside industry norms. There is no evidence that APS's programs are unreasonable in amount or design. The proposals by the intervenors focus solely on allocation, not on prudence.

Q. HOW DOES APS'S INCENTIVE PROGRAM BENEFIT CUSTOMERS?

A. APS's incentive compensation program is an integral part of how APS delivers safe, reliable, and affordable service. It drives measurable customer benefits by encouraging employees to meet or exceed performance targets tied to operational excellence. The program promotes behaviors and practices that reduce outages, improve response times, control costs, and support long-term system planning. Without effective incentive structures, APS customers would be at a disadvantage if APS was unable to attract, retain, and motivate the skilled workforce required to deliver safe, reliable, and affordable electric service.

Q. HOW DOES APS RESPOND TO CONCERNS ABOUT EMPLOYEE INCENTIVES BEING TIED TO FINANCIAL PERFORMANCE?

A. Financial discipline is an important component of incentive design. Financial metrics encourage cost control, capital efficiency, and long-term affordability, all of which directly benefit customers. In a capital-intensive utility, responsible

[13] Higgins Direct at 47-50; Smith Direct at 73-74.

financial performance supports credit quality, lowers borrowing costs, and ultimately reduces pressure on customer rates. These are all critical benefits that APS's cash incentive program helps deliver for customers.

Q. WHAT IS APS'S POSITION ON RECOVERY OF EMPLOYEE INCENTIVE COMPENSATION IN RATES?

A. APS accepts Staff's recommendation to address employee cash incentive compensation through a 50/50 sharing approach between customers and shareholders in this case. Ms. Blankenship discusses the revenue requirement impact of this change in her Rebuttal Testimony.

I want to emphasize that our willingness to propose reductions in this case should not be interpreted as a concession that the costs for items such as Board of Directors fees, D&O Insurance, and employee incentive compensation are not prudent, necessary, or beneficial to our customers. Instead, this willingness represents APS's efforts to achieve greater alignment with Staff and various intervenors in this case and deliver a reduced rate impact for customers.

VI. PENSION AND WORKFORCE PLANNING

Q. PLEASE BRIEFLY DESCRIBE THE TYPE OF PENSION BENEFIT THAT APS OFFERS ITS EMPLOYEES.

A. In 2003, APS reformed its pension benefit to offer an "account balance" plan, which is fully funded and managed by the Company, in place of the defined benefit plan that was previously available. Under the account balance plan, APS makes employer-only contributions to an individual account for each employee based on lifetime annuity at retirement or, in certain circumstances, as a lump sum distribution. This design provides employees with greater transparency, portability, and flexibility while preserving the lifetime income features associated with a pension benefit.

Q. HOW DOES THE PLAN DIFFER FROM A TRADITIONAL PENSION PLAN?

A. A traditional pension plan exposes the Company to increased risk, such as interest-rate volatility or underperforming investment returns that may lead to sharp increases in required Company contributions or workforce demographic shifts that may result in increased benefit payouts. By offering an account balance plan combined with a 401(k)-based plan, APS provides employees with meaningful retirement security and choice while maintaining predictable and manageable long-term costs. This approach supports employee retention and recruitment—particularly for highly sought, skilled utility workers—while protecting customers from long-term cost uncertainty associated with fixed-benefit pension structures, like interest rate changes, market performance, and demographic shifts that are outside of a utility's control.

Q. WHAT ROLE DO RETIREMENT BENEFITS PLAY IN SECURING AN EXPERIENCED, SKILLED WORKFORCE FOR APS?

A. Providing customers with reliable energy at the lowest cost possible depends on highly specialized employees. For instance, APS apprenticeships for positions such as electrician, lineman, automotive mechanic, and polyphase meterman are multi-year programs, typically four years in duration. I detailed in my Direct Testimony some of the duties our approximately 6,500 employees perform to help APS reliably serve our customers 24 hours a day, 365 days a year. Nationwide competition for experienced utility workers has grown increasingly intense, making it essential for APS to offer a comprehensive and competitive benefits program. The pension and other post-retirement employee benefits (OPEB) plans are a critical part of our total compensation package, helping us retain employees for the benefit of our customers while reducing costly turnover, recruitment, and retraining expenses. This investment in long-term retention is evident in our

workforce today: the average tenure of an APS employee is 11 years, and 40 percent of our employees have recorded 11 or more years of service through December 2025. APS's median tenure is double the median for a utilities sector employee and far higher than the median for all wage and salary workers based on the most recent United States Bureau of Labor Statistics data. APS employees dedicate their careers to our customers and community, and the pension reflects our dedication back to them.

Q. WHY SHOULD THE PENSION TRUST BE TREATED AS AN ASSET THAT EARNS A STANDARD REGULATED RETURN?

A. The pension trust reflects shareholder-supplied capital that APS has already committed to fund retirement benefits that employees have earned through their service to customers. Those funds are set aside in advance and invested prudently, just like other long-lived investments that support safe and reliable electric service. Treating the pension trust differently than other capital assets would be inconsistent with longstanding ratemaking practice and with how this Commission has treated APS's pension assets for more than four decades.

Q. HOW DOES THE PENSION TRUST BENEFIT CUSTOMERS?

A. Customers benefit directly from a well-funded, well-managed pension trust. The trust is adequately funded, conservatively invested, subject to independent oversight, and managed to a moderate expected return. It generates investment earnings that are reinvested in the trust and offset costs customers would otherwise bear through rates. Responsible funding also reduces the risk of future cost spikes, avoids federal insurance penalties associated with underfunded plans, and supports workforce stability. In that sense, the pension trust is not a legacy cost—it is a cost-containment tool and a reliability investment no different than substations, power lines, or any other steel-in-the-ground infrastructure customers count on every day for reliable, affordable service.

Earning a standard regulated return acknowledges that shareholders have supplied capital up front and that this capital, like other utility investments, supports ongoing service to customers. Arbitrarily adjusting the return on this asset—as AZLCG, RUCO, and Freeport recommend—would not eliminate the cost; it would instead create an inconsistency in ratemaking treatment and discourage prudent pre-funding that ultimately lowers long-term customer risk.[14]

Q. HAS APS HISTORICALLY INCLUDED PENSION ASSETS IN RATE BASE?

A. Yes. The Commission has approved the inclusion of pension assets and obligations in rate base across multiple rate cases spanning some 40 years. This consistent regulatory treatment has provided transparency and stability for customers, the Company, and the Commission. It reflects the widely accepted principle that rate base is not limited solely to new physical plant but includes prudently incurred capital costs where shareholder funds are used to support utility service and therefore warrants earning a standard return. Ms. Blankenship addresses these arguments in more detail from a financial accounting perspective.

Q. DO EMPLOYEE REPRESENTATIVES SUPPORT APS'S REQUEST TO INCLUDE THE PENSION TRUST IN RATE BASE?

A. Yes. Local Unions of the International Brotherhood of Electrical Workers (IBEW) expressly supports APS's inclusion of pension assets in rate base. In his direct testimony, IBEW witness Dennis Carpenter testified that APS's pension investments are "crucial to the retention and support of these highly in-demand workers" and that the Commission "should support and encourage such proactive provision of competitive wage and benefit packages."[15] IBEW further confirmed

[14] Higgins Direct at 9, 61.

[15] IBEW, Direct Testimony of Dennis Carpenter (Mar. 2, 2026) at 11.

that APS has funded these pension benefits and should be permitted to recover the associated costs.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

REBUTTAL TESTIMONY OF JACOB TETLOW

On Behalf of Arizona Public Service Company

Docket No. E-01345A-25-0105

April 3, 2026

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REBUTTAL TESTIMONY OF JACOB TETLOW
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-25-0105)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Jacob Tetlow. I am Executive Vice President of Non-Nuclear Operations and Chief Operating Officer of Operations at Arizona Public Service Company (APS or Company), and my business address is 400 N. 5th Street in Phoenix, Arizona.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes. I filed Direct Testimony on June 13, 2025.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to Staff and intervenor testimony on post-Test Year plant (PTYP) and specific APS capital projects. My testimony is also intended to address arguments and perspectives from intervenors and the Utilities Division (Staff) of the Arizona Corporation Commission (Commission) concerning Palo Verde Generating Station (PVGS), APS's workforce development programs, and how APS engages with large, high load factor customers contributing to significant growth in the Company's service territory. I also address intervenor testimony regarding APS's current status providing for Coal Community Transition (CCT) needs.

I do not address every detail related to Staff and intervenor recommendations, and it should not be interpreted that I agree with any of their positions unless specifically stated in my testimony.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony demonstrates that APS's PTYP investments, such as the Agave Battery Energy Storage System (BESS) project and the Redhawk Power Plant (Redhawk) Makeup Water Surge Pond (MWSP) project, reflect prudently invested capital that helps APS provide reliable service at the lowest cost possible. My testimony also provides additional support for the PVGS Unit 2 lease buyback buyout transaction, which is intended to secure continued long-term access to this critical resource for Arizona and the Southwest region as a whole. Moreover, I discuss the significant long-term values delivered to customers by APS's transmission investments since the advent of Federal Energy Regulatory Commission (FERC) formula rates, and describe the Company's current approach to contracting for service with large, high load factor customers, such as data centers, which is part of APS's "growth pays for growth" strategy aimed at protecting existing APS customers from potential cost shifts and reliability risks.

III. POST-TEST YEAR PLANT ADDITIONS

Q. HAS APS UPDATED ITS PTYP REQUEST?

A. Yes. In response to data requests from the Staff (specifically Staff discovery DR 5.6), the Company provided a list of projects that went into service by December 31, 2025. Staff witness Dr. Randell M. Johnson performed an engineering review of various projects and both he and Staff witness Ralph C. Smith recommend inclusion of all completed PTYP projects.[1]

The figures represented in Mr. Smith's testimony reflect estimated trial-balance cost data provided in discovery, while the costs reflected in APS's Rebuttal

[1] Staff, Direct Testimony of Dr. Randell M. Johnson (Mar. 2, 2026) (Johnson Direct) at 63; Staff, Direct Testimony of Ralph C. Smith (Mar. 2, 2026) (Smith Direct) at 19.

Testimony, specifically the updated pro forma adjustments sponsored by APS witness Elizabeth A. Blankenship, represent final costs for plant booked to service before the end of 2025. Please see attachments JT-01RB through JT-05RB for a list of projects and their corresponding final costs, which reflect a $50 million decrease to rate base as compared to the Direct Testimony provided by Mr. Smith.

Q. DESCRIBE CHANGES FROM THE INITIAL PTYP REQUEST FILED WITH THE APPLICATION TO THE FINAL PTYP SUBMITTED IN STAFF DR 5.6.

A. The PTYP filing in the application included only one month of actual project data and 11 months of project forecasts. As a result, APS is no longer seeking cost recovery for a variety of projects identified in my Direct Testimony because they were not actually completed as of December 31, 2025. By contrast, several other projects, including the Ironwood Solar and Sundance Expansion generation projects, were completed ahead of schedule and placed into service by December 31, 2025. In general, numerous factors—including supply chains, contractor availability, and weather, among others—drive APS's ability to complete projects ahead or behind schedule. As is typical in APS rate cases, the PTYP projects for which APS is seeking recovery in this case have been updated to reflect projects that went into service during 2025.

Q. PLEASE DESCRIBE THE SELECTION PROCESS FOR SUNDANCE EXPANSION AND IRONWOOD SOLAR GENERATION PROJECTS.

A. Both the Sundance Expansion and Ironwood Solar generation projects were selected through the Company's 2023 All-Source Request for Proposal (ASRFP) process. Through this competitive process, APS ensures projects are selected based on their ability to satisfy system needs at the lowest cost to customers. Please see

APS witness Michael Eugenis' Rebuttal Testimony for more information on APS's ASRFP process.

Q. WHAT IS THE SUNDANCE EXPANSION PROJECT?

A. The Sundance Expansion generation project added two 45-MW General Electric (GE) LM6000 combustion turbines (CT) at the Sundance Power Plant (*see* Figure 1 below), increasing natural gas-fired capacity by a total of 90 MW—sufficient to serve approximately 14,000 Arizona homes. The new units enhance system reliability for APS customers and provide critical energy during peak demand, often in the late afternoon and evening hours. The project increases APS's ability to rely on renewable resources by providing flexible, dispatchable generation that is fast-starting, fast-ramping, and capable of multiple daily starts. These attributes support the integration of additional renewable energy resources into the APS generation portfolio while maintaining system reliability. Locating the units at the Sundance Power Plant allows the project to integrate with the site's existing gas turbines, balance-of-plant equipment and systems, and the plant's control room and control system. The total cost of the project was $175.2 million and the facilities were placed in service on November 14, 2025.

Figure 1. Sundance Expansion Project



Q. WHAT IS THE IRONWOOD SOLAR PROJECT?

A. Ironwood Solar generation project (*see* Figure 2 below), APS's largest-owned solar power plant, was placed in service on December 4, 2025. This 168 MW photovoltaic facility uses single-axis tracking that captures west-facing solar production later in the day. This means that Ironwood Solar is capable of producing approximately two to three times more power during peak load hours than an average, predominantly south-facing system. Ironwood Solar works in tandem with APS's existing generation portfolio to provide low-cost energy to customers, which can be used immediately or stored by APS's fleet of battery energy storage resources. The total cost of the project was $288.7 million.

Figure 2. Ironwood Solar



Q. DO ANY INTERVENORS OPPOSE APS'S PTYP REQUEST?

A. Two intervenors expressed concerns around the following reliability projects that went into service before the end of the PTYP period.

- Agave BESS – The Agave BESS is a 150 MW energy storage facility co-located with the existing Agave Solar Plant. The project supports reliability and enables APS to capture excess solar generation during midday hours by

charging the battery and to dispatch stored energy during the evening period when solar generation declines. My testimony explains that the Agave BESS project is a reliable and cost-effective resource for customers.

- Redhawk MWSP – The existing MWSP at Redhawk provides storage for water used in plant cooling, fire protection, and other essential plant water systems. Constructing a second Redhawk MWSP provides redundancy for this critical and dispatchable 1,100 MW generation resource. My testimony explains why this is a critical project to ensure reliability of APS's generation fleet.

Q. DID APS PROCURE THE AGAVE BESS PROJECT BECAUSE OF THE COMPANY'S CLEAN ENERGY COMMITMENT?

A. No. Arizona Free Enterprise Club (AZFEC) asserts that APS's clean energy commitment drove the decision to construct the Agave BESS project and that the technology is not cost competitive.[2] As described in more detail in Mr. Eugenis' Rebuttal Testimony, the Agave BESS project was procured through the Company's ASRFP process, which involves evaluating bids across all technology types to ensure cost-effective and reliable resource procurements. The project was ultimately selected as part of a resource portfolio that met resource adequacy and reliability requirements at lowest cost.

Q. DO BATTERY ENERGY STORAGE FACILITIES REQUIRE MORE CAPITAL INVESTMENTS AND MAINTENANCE EXPENSES AS COMPARED TO THERMAL RESOURCES?

A. No. AZFEC witness Isaac Orr incorrectly asserts that round-trip efficiency losses and degradation within the first 15 years of BESS facility operations materially reduce the economic value of battery resources relative to thermal generation.[3] That

[2] AZFEC, Direct Testimony of H. Sterling Burnett, Ph.D. (Mar. 2, 2026) at 15-16.
[3] AZFEC, Direct Testimony of Isaac Orr (Mar. 2, 2026) at 6-7.

assertion is based on an incomplete and asymmetrical comparison. All resource types, including thermal generation—require ongoing maintenance and periodic sustaining capital investments to remain reliable, safe, and cost effective over their operating lives. Thermal resources are no exception.

Like battery energy storage assets, thermal generating resources follow a structured long-term maintenance and capital reinvestment strategy, typically planned over a 30-year operating horizon, to sustain reliability, efficiency, and asset life. This includes routine preventive and predictive maintenance (such as inspections, testing, monitoring, and minor repairs), regular planned outages for capital overhauls and equipment inspections, and scheduled major maintenance cycles that require sustaining capital investments for refurbishing or replacing large components. Maintenance activities include corrective actions for performance issues, targeted capital projects, system upgrades, and compliance-driven modifications to keep units safe, reliable, and cost effective.

Q. DO THERMAL AND BESS RESOURCES HAVE SIMILAR REQUIREMENTS RELATED TO PERIODIC OVERHAULS, EQUIPMENT REPLACEMENTS, AND OTHER SIGNIFICANT REINVESTMENT TO ENSURE SAFE AND RELIABLE OPERATION?

A. Yes. Specifically with respect to natural gas-fired CTs and combined-cycle (CC) generating units, major capital investments are an expected and recurring part of long-term operation. These units periodically require capital-intensive overhauls, rebuilds, and life-extension work, including refurbishment or replacement of major components such as turbines, generators, hot-gas-path components, heat recovery steam generators, balance-of-plant equipment, control systems, and environmental compliance systems. For example, major scheduled maintenance activities for GE LM6000 units—which are the most widely used aeroderivative gas turbines both

nationally and within the Company—comprise borescope inspections every 4,000 operating hours, combustion system inspections every 15,000 operating hours, hot-gas-path overhauls at 25,000 operating hours, and major overhauls every 50,000 operating hours, in addition to various other planned and unplanned maintenance tasks. These measures are essential for mitigating wear, thermal fatigue, obsolescence, emissions compliance, and performance decline that develop over time, thereby supporting reliable operation throughout the equipment's multi-decade service life.

Importantly, these sustaining capital investments are neither unusual nor unique—they are a normal and expected characteristic of long-lived thermal assets, just as periodic component replacement and augmentation are for BESS. Assertions that BESS facilities uniformly fail at 15 years requiring a capital replacement event while gas-fired CTs or CCs operate for 30 years without major overhauls or reinvestment are incorrect. Both resource types require planned overhauls, targeted capital upgrades, and ongoing sustaining investments over their operating lives. When evaluated on a consistent lifecycle basis, thermal generation is not exempt from periodic capital reinvestment, and Mr. Orr's analysis, therefore, relies on a flawed and inconsistent comparison.

Q. DOES MR. ORR OVERSTATE THE NEEDS FOR CAPITAL OVERHAULS ASSOCIATED WITH BATTERY ENERGY STORAGE ASSETS?

A. Yes, dramatically so, because, per the manufacturer specifications, the CATL 306ah cells, which are used for the Agave BESS, have a lifecycle of greater than 10,000 cycles. Therefore, the batteries will maintain more than 70% of their initial capacity after 27 years in service and completing a full cycle every day. Furthermore, augmentation may be performed at some point during the life of the

battery to bring the capacity back to 100%. As described by Mr. Eugenis, long-term maintenance costs and sustaining capital investment costs were evaluated as part of the Company's ASRFP process.

Q. COULD APS HAVE CONTINUED TO OPERATE CHOLLA POWER PLANT (CHOLLA) IN LIEU OF BUILDING THE AGAVE BESS?

A. No. APS was mandated by federal law to cease burning coal at Cholla by April 30, 2025. This obligation arose from Clean Air Act requirements, including the source-specific Regional Haze State Implementation Plan revision approved by the United States Environmental Protection Agency (EPA) in 2017, which made the coal cessation requirements federally enforceable[4]. Although APS is evaluating conversion of the Cholla facility to natural gas in its 2026 Integrated Resource Plan (IRP), such a conversion would not eliminate the need for the Agave BESS.

Q. DID ANY INTERVENORS PROVIDE SUPPORT FOR THE AGAVE BESS?

A. Yes. Both Staff and Local Unions of the International Brotherhood of Electrical Workers (IBEW) support the investment, with IBEW stating that the investment is reasonable and prudent and contributes to serve demand when solar is not performing at peak capacity.[5] In addition, Dr. Johnson evaluated this project extensively and found that the plant is "dispatchable in alignment with market signals, and capable of providing real power, reactive power, voltage regulation, and fast frequency response."[6] He also noted that the costs of the Agave BESS are consistent with National Renewable Energy Laboratory's benchmark estimates and that the plant is "necessary, prudent, and used and useful for providing electric

[4] EPA 40 CFR Part 52, *Approval and Revision of Air Plans; Arizona; Regional Haze State and Federal Implementation Plans; Reconsideration*, 82 Fed. Reg. 15,139 (Mar. 27, 2017).

[5] Johnson Direct at 19; IBEW, Direct Testimony of James Crutchfield (Mar. 2, 2026) at 4 and 7.

[6] Johnson Direct at 18-19.

service and is justified for inclusion in rate base with depreciation consistent with its expected service life."[7]

Q. EXPLAIN WHY REDHAWK IS AN IMPORTANT GENERATING RESOURCE FOR APS.

A. Redhawk is one of APS's most important generating resources because it provides a large block of highly reliable, efficient, and flexible capacity that supports customer load and system reliability throughout the year. As one of the largest and most efficient CC natural gas facilities in the APS fleet, Redhawk is frequently committed and dispatched and provides not only energy and capacity, but also essential reliability services that help maintain system balance as load patterns change and variable renewable generation fluctuates. Given its size, efficiency, and operational role across all seasons, the extended loss of Redhawk—even during the fall, winter, and spring months—would pose significant reliability risks and increase customer exposure to higher costs and less certain market alternatives.

Q. WHY IS THE SECOND REDHAWK MWSP A NECESSARY INVESTMENT FOR THE COMPANY?

A. The existing MWSP represents a single point of failure for Redhawk that is eliminated with the addition of a second MWSP. Constructing and maintaining a redundant MWSP allows for planned maintenance outages for plant water supplies—both on-site and at PVGS—without site unavailability or reduced plant output. The additional MWSP also expands makeup water capacity to support future generation at the Redhawk site—such as the eight LM6000 units currently under construction, which will expand generation capacity at this regionally important power plant. The second MWSP also provides a redundant water supply for the site fire protection systems.

[7] Johnson Direct at 18-19.

The plant was originally constructed with a single MWSP and was designed to operate using a water supply comprised of 90% treated effluent water from PVGS and 10% groundwater, consistent with its Certificate of Environmental Compatibility (CEC). The operational run hours indicated that, in their initial years of operation, the Redhawk units were appropriately designed to align with the capacity of the existing MWSP and the PVGS effluent water supply. However, as plant operating hours have increased during the shoulder months in recent years (*i.e.,* fall, winter, and spring), the risk of derates (*i.e.,* forced reductions in plant output) and complete plant outages at Redhawk have increased due to periodic insufficient water levels from the MWSP. Because the plant relies on treated water from PVGS, this risk is further heightened during PVGS water resource outages, which occur in the fall and spring each year.

Finally, the installation of a second MWSP at Redhawk allows the site to achieve these operational advantages while maintaining compliance with the current CEC by utilizing greater than 90% treated effluent water from PVGS and less than 10% groundwater. As such, the second MWSP ensures environmental regulatory compliance while maintaining more sustainable operations (less groundwater extraction) over the long term.

Q. DID APS CONSIDER ALTERNATIVES TO INSTALLING A SECOND MWSP?

A. Yes. APS evaluated restoring an out-of-service Graver Clarifier System, which is a water softening and clarification system to treat well water and remove silica, enabling cooling towers to operate efficiently at 13 to 15 cycles. However, the Graver Clarifier System would have required reliance on 100% groundwater, which does not meet the plant's CEC requirements. Additionally, the system would have resulted in higher operating and maintenance expenses, including the need for

four full-time staff members and ongoing costs for chemicals and their disposal. More wells would have been needed to handle future raw water maintenance demands. Ultimately, APS chose to install the second MWSP at Redhawk because it presented the best balance of operational, environmental, and financial impacts compared to the alternatives. As such, the second MWSP was the option that was in the best interest of APS customers.

Q. PLEASE EXPLAIN THE CRITICALITY OF HAVING THE SECOND POND AS IT RELATES TO UPCOMING PLANNED MAINTENANCE OUTAGES.

A. The existing MWSP will soon require extensive liner maintenance, which is estimated to take a minimum of six to eight months to complete. As with any major capital project, APS cannot guarantee that the completion of this work will be limited to minimum expected timeframes. Without a second MWSP, the Company would be required to take the entirety of Redhawk's generation capacity out of service during the full timeframe necessary to complete relining of the existing MWSP. As discussed above, Redhawk offers significant reliability and financial advantages beyond capacity alone, including ancillary services such as regulating reserves, and these resource values remain critical even during the fall, winter, and spring months of the year. The absence of these resources provided by Redhawk during the fall, winter, and spring still represents an unacceptable reliability risk for APS. Moreover, to the extent relining work cannot be completed during these months (*i.e.,* during the six to eight month minimum relining project timeframe), critical generation capacity and energy provided by Redhawk would be unavailable during APS's peak demand periods over the summer months. This further compounds the unacceptable reliability risks posed by a relining project at the existing MWSP without a second pond (*i.e.,* the existing MWSP is the sole source

of water for the plant, including necessary water supplies for critical plant fire suppression systems).

APS witness Kent C. Walter provides more detail on key reliability risks associated with a long-term, six to eight month dual-unit outage at Redhawk, which would become necessary during relining of the single, existing MWSP. As described further by Mr. Walter, these risks increase tremendously to the extent Redhawk remains in outage into the summer months. For all of these reasons, among others, a prolonged Redhawk outage, which would be necessary with only one MWSP undergoing a relining project, would expose APS customers to unacceptable reliability risks.

Q. DID APS EXCLUDE ALL GROWTH-RELATED PLANT FROM ITS POST-TEST YEAR PLANT REQUEST?

A. Yes. As discussed in my Direct Testimony, capital spending driven by customer-initiated projects was excluded from the Company's PTYP request.

Q. HAVE ANY PARTIES PROVIDED TESTIMONY THAT CALLS INTO QUESTION THE METHODOLOGY DISCUSSED IN YOUR DIRECT TESTIMONY FOR REMOVING GROWTH-RELATED PLANT FROM THE COMPANY'S PTYP REQUEST?

A. No.

Q. SHOULD THE GENERATION PROJECTS IN APS'S PTYP REQUEST BE REMOVED WITH GROWTH RELATED PLANT?

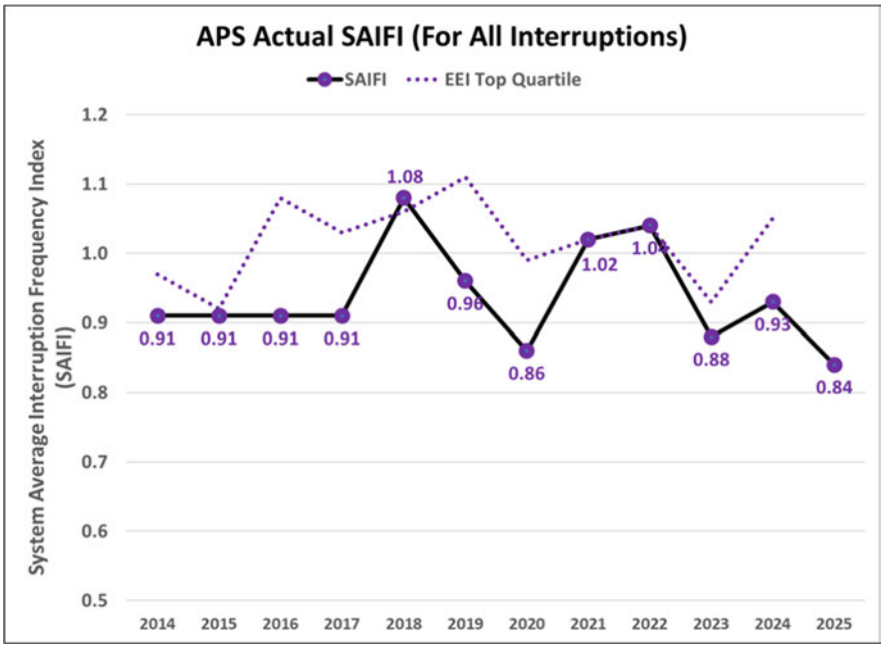
A. No. None of the generation projects, including the Sundance Expansion, Ironwood Solar, and Agave BESS projects, were developed in response to a Project Initiation Request by a specific customer. These generation projects were necessary to serve existing customers.

IV. RELIABILITY

Q. ARE THERE MORE RECENT RELIABILITY METRICS THAN THOSE APS PROVIDED IN ITS APPLICATION?

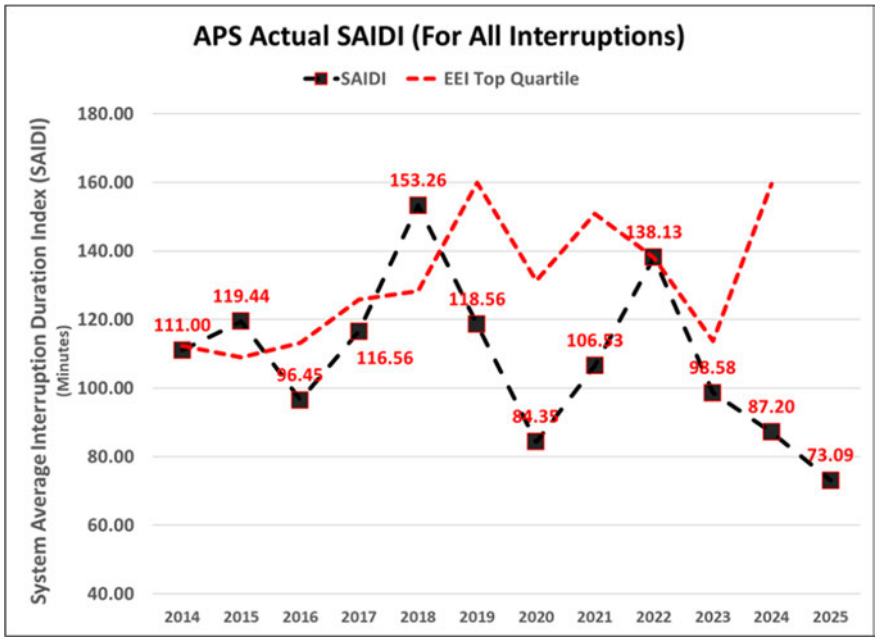
A. Yes. Figures 3 and 4 show APS's updated System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) results through 2025, respectively, alongside Edison Electric Institute (EEI) benchmarks through 2024. Because SAIFI reflects the frequency of outages experienced by the average customer and SAIDI measures the duration of service interruptions experienced by the average customer, lower values in both measures indicate stronger performance. As demonstrated in Figures 3 and 4, APS ranked in the top quartile for 10 of the past 11 years in SAIFI and eight of the past 11 years in SAIDI, with 2025 performance improving further over 2024. These scores demonstrate that APS customers experience fewer outages and shorter outage durations than customers at peer utilities.

Figure 3. APS Actual SAIFI – 2014-2025



A lower number indicates better performance

Figure 4. APS Actual SAIDI – 2014-2025



A lower number indicates better performance

V. PALO VERDE GENERATING STATION

Q. DID APS COMPLETE ITS PURCHASE OF THE 92 MW INTEREST IN UNIT 2 DESCRIBED IN THE COMPANY'S APPLICATION?

A. Yes. The purchase was completed on September 22, 2025.

Q. DID INTERVENING PARTIES PROVIDE TESTIMONY ON THE PURCHASE?

A. Yes. Staff and IBEW support the purchase and recognize the criticality of retaining this base load generation resource along with the significant benefits that come with continued operation of PVGS. Staff recognizes that interest in nuclear generation is increasing as a means to meet rising electric demand in areas experiencing load growth even outside of Arizona.[8] IBEW states that "purchasing this interest and supporting PVGS operations will be good for APS ratepayers' energy demands and their local economy."[9]

[8] Smith Direct at 47.

[9] IBEW, Direct Testimony of Dennis Carpenter (Mar. 2, 2026) (Carpenter Direct) at 14.

AARP opposes the purchase and any associated PTYP investments, and questions whether the decision was cost effective.[10] Mr. Eugenis explains in Rebuttal Testimony the Company's analysis demonstrating that the purchase is in the best long-term economic interests of customers.

Q. IS THE COMPANY REQUESTING RECOVERY OF ANY PTYP INVESTMENTS RELATED TO THE PURCHASE OF THE ADDITIONAL INTEREST IN PVGS UNIT 2?

A. No. All of APS's PTYP investments listed in Attachment JT-02RB, and provided in the Company's response to Staff DR 5.6, would have been necessary regardless of whether APS continued to lease or own the additional 7% interest in PVGS Unit 2.

Q. WHY DID APS COMPLETE THIS PURCHASE RATHER THAN EVALUATE WHETHER OTHER RESOURCES MIGHT HAVE LOWER INSTALLED CAPITAL COSTS WHEN THE LEASE ENDED IN 2033?

A. Mr. Eugenis discusses in detail the economic benefits to APS customers of this purchase. But beyond the economic benefits to customers and the State of Arizona, discussed in my Direct Testimony, nuclear generation is important for the following reasons:

- Nuclear generation provides critical resource diversity for APS's current fleet of generation resources, which also includes coal- and gas-fired generation, renewable resources like solar and wind, and significant battery energy storage facilities. Resource diversity is an important value in resource planning that helps ensure APS customers are not exposed to reliability risks associated with over-reliance on only a limited set of resources. Resource diversity also enables APS to leverage complimentary

[10] AARP, Direct Testimony of Paul J. Alvarez (Mar. 2, 2026) at 37-38.

values across different resource types (*i.e.,* balancing conventional, around-the-clock firm resources, like PVGS, with a variety of dispatchable generation and storage resources, coupled with very low-cost intermittent renewable resources).

- Nuclear generation resources provide very high-capacity factors at 92.6% across the industry as compared to 56.7% for natural gas resources, that provide the second highest capacity factors. In other words, nuclear resources deliver more electricity per unit of installed capacity than wind, solar, coal, and gas resources. This is especially important during the summer season and its extreme weather conditions when the Company depends on PVGS to provide reliable generation on a 100% capacity-factor basis.
- PVGS, although the largest power producer in the Western United States, has a tremendous use of land efficiency when compared to wind, solar and coal. Nuclear sites generally use land 50 times more effectively than coal resources, and 18 to 27 times more effectively than utility scale solar.
- Over its operating life, PVGS will have emissions that are comparable to wind and lower than solar, even while delivering consistent, firm, thermal energy.

Q. WHY DOES APS'S ANALYSIS CONCLUDE THAT PVGS WILL BE OPERATIONAL BEYOND THE CURRENT LICENSE PERIOD?

A. Given the importance of nuclear generation to APS's resource portfolio, the Company plans to continue operating the plant beyond its current license and is extremely confident its application to renew the PVGS operating license will be approved by the Nuclear Regulatory Commission (NRC).

In 2011, the NRC granted PVGS a 20-year operating license extension and expressly provided the opportunity for the plant to seek an additional renewal for continued operation. To date, the NRC has not denied a license renewal application for an operating nuclear reactor. While the NRC may determine that an application is incomplete and suspend its review until identified issues are addressed, an outright denial is highly unlikely. APS has filed its Notice of Intent to apply for Subsequent License Renewal, signaling the Company's intent to file the renewal application at the end of 2027. This timing provides ample time to address any potential NRC questions or requests for additional information.

In addition, PVGS engaged an independent third-party engineering firm in 2020 to conduct a planning assessment for subsequent license renewal. This planning assessment took into account PVGS's current outlook of necessary strategic investments to facilitate subsequent license renewal for operations beyond 2046. In light of this investment plan, the 2020 planning assessment concluded that there were no meaningful impediments that would preclude successful NRC approval for an additional 20 years of operation for the PVGS units (operating nuclear reactors).

Recent industry experience further supports this conclusion. Several operating nuclear facilities have submitted license renewal applications within the past few years, and the NRC approved license renewals for 13 reactors in 2025 alone. More than 20 additional plants have publicly indicated their intent to renew their licenses, and the current NRC is working to reform its processes to facilitate these approvals.

For these reasons, based on everything the Company knows today, APS sees no reason to doubt that the NRC will grant approval for PVGS to operate for an additional 20 years beyond the current license expiration.

VI. WORKFORCE PLANNING

Q. DID ANY PARTIES EXPRESS CONCERN AROUND APS'S WORKFORCE PLANNING?

A. Yes. IBEW expressed that certain open positions are not being filled through external job postings and recommended that APS implement additional apprenticeship programs to help ensure a qualified workforce to support the operation of new power plants and generating units.[11] The Company acknowledges the ongoing challenges associated with recruiting and retaining qualified journeyman-level employees, particularly in geographically remote or otherwise difficult-to-staff locations. APS agrees that expanding apprenticeship programs is appropriate and is actively in the process of scaling those efforts.

Q. WHAT OTHER STEPS HAS APS TAKEN TO ADDRESS WORKFORCE PLANNING CHALLENGES?

A. The Company has implemented, and continues to advance, a multi-pronged strategy focused on expanding the external talent pool, reducing barriers to entry for qualified candidates, and increasing the competitiveness and visibility of these roles.

First, the Company has enhanced location-based financial incentives for hard-to-fill areas, including increased sign-on bonuses for select lineman journeyman and crew foreman positions. These incentives are targeted to specific locations with persistent staffing challenges and are actively monitored to assess effectiveness and ensure alignment with labor market conditions.

[11] Carpenter Direct at 14.

Second, to broaden the geographic reach of qualified candidates, the Company has implemented travel reimbursement for out-of-state journeyman applicants, reducing the financial burden associated with testing and pre-employment requirements. In parallel, the Company has expanded remote testing access through third-party testing centers, allowing qualified external candidates to complete required written examinations closer to their home locations rather than traveling to Arizona.

Third, the Company has made targeted qualification flexibility adjustments where appropriate, including allowing candidates to apply with a Class A Commercial Driver's License (CDL) permit (rather than a full license at time of application), and permitting certain manual transmission restrictions for non-hauling roles. These changes maintain safety and operational standards while removing unnecessary barriers that previously limited the external candidate pool.

Fourth, the Company has significantly increased targeted marketing and outreach efforts for hard-to-fill journeyman roles. These efforts include paid job postings, social media campaigns, direct outreach to prior qualified applicants, and industry-specific marketing strategies aimed at increasing awareness of opportunities in challenging locations. The Company is also exploring advanced digital marketing techniques such as geofencing around industry events, and partnerships with external organizations to further extend reach.

Finally, the Company continues to evaluate additional strategies focused on out-of-state talent attraction, including virtual hiring events, location-specific marketing materials, and partnerships with labor organizations and industry

networks. These initiatives are tracked, evaluated, and adjusted as necessary to ensure they deliver measurable improvements in applicant flow and hiring outcomes.

Collectively, these actions demonstrate the Company's proactive and ongoing commitment to addressing external journeyman staffing challenges in hard-to-fill areas while maintaining operational excellence, safety standards, and workforce stability.

VII. PLANNING AND SERVING LARGE LOAD CUSTOMERS

A. *Large Customer Project Queue*

Q. DO YOU AGREE WITH MICROSOFT CORPORATION (MICROSOFT) THAT REFORMS TO THE COMPANY'S LOAD INTERCONNECTION QUEUE PROCESS ARE WARRANTED?

A. No. The Company does not agree that reforms to the Large Customer Project Queue are appropriate at this time. Microsoft witness Mark E. Garrett suggests that APS should model its process after the Large Generator Interconnection Procedures (LGIP), which is based on reforms for generation interconnection recently adopted by FERC.[12] However, APS's Large Customer Project Queue process, for customers requiring 25 MW or greater with a load factor of 92% or greater, process is already structured around the same principles as the LGIP, including project viability, planning certainty, and appropriate cost responsibility. For example, APS requires prospective customers to submit a non-refundable payment of $25,000 to cover the costs of a Feasibility Study upon entry into the queue. If the customer elects to proceed after completion of that study, and generation capacity to serve the customer has been identified, APS requires an executed Load Commitment Agreement (LCA) and an additional non-refundable

[12] Microsoft, Direct Testimony of Mark E. Garrett (Mar. 2, 2026) (Garrett Direct) at 13.

payment to cover the costs of the System Impact Study and Facilities Study. Customers will be provided with a cost estimate of the System Impact Study and Facilities Study after APS has line of sight to the generation to reliably serve the customer load. In addition, prospective customers must demonstrate site control within a specified period following completion of their studies.

These requirements are intended to ensure costs to complete studies are covered by the prospective customer and ensure that projects advancing through the queue are viable. Accordingly, APS believes its current Large Customer Project Queue framework already incorporates the key principles of the FERC generator interconnection process, while preserving the flexibility necessary to support economic growth in Arizona and ensuring costs to serve large load customers are not passed onto other customers.

Q. WHAT IS CURRENTLY THE MOST SIGNIFICANT CONSTRAINT TO SERVE ADDITIONAL LARGE, HIGH LOAD FACTOR CUSTOMERS, SUCH AS DATA CENTERS?

A. Procuring generation resources to serve the volume of data center and other large load requests is currently the greatest challenge the utility industry faces in serving uncommitted customers. In this respect, uncommitted customers are those with whom APS has not yet executed a contractual commitment to provide service. While imposing further constraints on prospective customer projects within the Large Customer Project Queue could eliminate some speculative requests in the queue, such changes would not resolve the underlying generation constraints that are driving the large size of the current queue. In other words, regardless of whether speculative entities currently occupy positions within APS's uncommitted Large Customer Project Queue, the lack of excess generation resources available within the region do not allow for APS (or any other entity, such as third-party generation

service providers (GSPs)) to serve this uncommitted growth within a near-term time horizon.

Q. IS ANY PENDING ACTION ON THE FEDERAL LEVEL PROPOSED TO ASSIST IN SERVING LARGE, HIGH LOAD FACTOR CUSTOMERS, SUCH AS DATA CENTERS?

A. Yes. In October 2025, FERC issued an Advance Notice of Proposed Rulemaking addressing large load interconnections, signaling its intent to establish uniform procedures in this area. Should FERC ultimately adopt new requirements, the timeline for implementing those changes would likely be comparable to the timing associated with the reforms proposed by Microsoft. For these reasons, it would be premature to make changes to the Company's Large Customer Project Queue process before additional generation is available and the FERC proceeding is complete.

Q. HOW DO YOU RESPOND TO MICROSOFT'S CONCERNS REGARDING SPECULATIVE LOAD REQUESTS?

A. Microsoft suggests that additional requirements, such as cash deposits and milestone payments, would reduce speculative projects in the APS Large Customer Project Queue, improve planning, and mitigate the risk of under-recovered or stranded assets.[13] While APS agrees that some speculative requests may exist within the current queue, those requests do not affect APS's load forecasts or resource planning. This is because APS does not include prospective customers in its long-range forecasting until they have executed a binding commitment for service (see Section VII(B), describing the LCA mechanism). Moreover, the Company does not believe Microsoft's proposed changes would discourage

[13] Garrett Direct at 13-14.

speculative requests from entering the queue before the Company has line of sight to the generation that could be used to serve them.

Q. WHAT MEASURES HAS APS IMPLEMENTED TO ENSURE THAT IT IS NOT COMMITTING RESOURCES TO PROSPECTIVE CUSTOMER PROJECTS THAT LACK COMMERCIAL VIABILITY?

A. It is essential that resources committed to serving prospective customers do not become an economic burden that other APS customers must bear if those prospective customers do not—for whatever reason—pay the full costs of new resources procured to serve growth. For this reason, once resources become available to serve a prospective customer in the Large Customer Project Queue, APS requires the customer to execute a Load Commitment Agreement (LCA), which is authorized under the current terms in APS's tariff. Included with the Electric Supply Agreement (ESA), the LCA specifies the customer's load ramp and commits the customer to paying the costs associated with the minimum demand identified in its project request before their load is included in the Company's long-range forecast. Among other terms designed to protect existing APS customers, the LCA also requires collateral to secure LCA obligations, long-term commitments, and early termination payments. This approach significantly reduces the risk that APS will build or procure generation resources to serve speculative loads, thereby mitigating the risk of stranded assets or cost shifts to other APS retail customers.

Q. WHY WOULD INCREASED CASH DEPOSITS ALONE BE INEFFECTIVE IN REDUCING THE POTENTIAL FOR SPECULATIVE REQUESTS FOR SERVICE IN APS'S LARGE CUSTOMER PROJECT QUEUE?

A. APS also disagrees that increased cash deposits would meaningfully reduce speculative requests. APS requires deposits under its LGIP and has not found those

deposits to be an effective deterrent, particularly for customers with substantial financial resources. Further, requiring customers to post deposits equal to the estimated cost of long-lead equipment would first require completion of a System Impact Study, which typically takes 90 to 120 days, in addition to the time required to complete a Feasibility Study. This approach would likely result in redundant evaluations if multiple projects are studied together and one or more customers elect not to proceed after receiving cost estimates. Alternatively, performing each of the required studies individually before requiring the deposit would introduce additional delays for customers in the queue. While milestone payments may encourage some projects to withdraw from the queue, those projects would nonetheless remain in the process for several months before doing so. APS maintains that its current approach (*i.e.,* requiring execution of an LCA after generation resources are identified and before the Company completes System Impact and Facilities Studies and a customer is required to provide deposits for long-lead equipment and other infrastructure—is reasonable).

Q. IS EXPANDING THE ALTERNATIVE GENERATION (AG-X) PROGRAM HELPFUL TO SERVING GROWTH?

A. From the standpoint of accelerating service, nothing about the AG-X program would enable service sooner than reliance on APS for generation resources. The broad absence of additional or excess generation resources across Arizona and the wider United States Southwest region is simply a reality that additional market access will not automatically cure. For many years now, whether through its competitive ASRFP process or the Company's Integrated Resource Plan (last presented in August of 2023), APS has widely communicated to the market that it was experiencing rapid and sustained load growth. While an expanded AG-X program may be a different means for customers to access GSP-supplied generation, such a program would not alter the underlying demand that drives the

need for additional generation supplies. In other words, GSPs operating through the AG-X program are no better positioned than APS to bring forth the additional generation resources needed to serve growing customer demand within the Company's service territory. In his Rebuttal Testimony Mr. Walter describes further concerns APS has with additional reliance on the AG-X program.

B. *Load Commitment Agreements*

Q. WHY IS THE LCA NECESSARY TO SERVE LARGE CUSTOMERS SUCH AS DATA CENTERS?

A. The LCA is designed to create financial protections for APS's other customers, beyond the protections that currently exist in the Premise Addendum (PA). Due to the scale of new large, high load factor customers coming into APS's service territory, which in many cases are hundreds if not thousands of MWs in size per customer, APS must procure more generation resources to serve these types of customers than at any time before in its history. As described in more detail by APS witness Chris R. Bauer in his Rebuttal Testimony, the LCA is a necessary and appropriate response to the economic risks posed by the influx of these new large, high load factor customers, given the infrastructure investments and expenditures required to meet this growing demand. The terms of the LCA ensure that when the Company invests in infrastructure improvements or incurs other costs or expenses necessary to serve a large customer, other customers are protected from cost shifts in the event the new large customer leaves the Company's service territory. The key financial terms of the LCA are described in more detail by Mr. Bauer in his Rebuttal Testimony.

Q. DID ANY OF THE PARTIES IN THIS RATE CASE WEIGH-IN AS TO THE REQUIREMENT FOR DATA CENTERS AND SIMILAR LARGE LOAD CUSTOMERS TO EXECUTE AN LCA BEFORE TAKING SERVICE?

A. Yes. Generally, those parties either supported APS's LCA or advocated for more stringent terms. For example, Residential Utility Consumer Office (RUCO) witness Dustin Madsen generally supports the requirements for LCAs that APS has proposed, including the use of specific terms consistent with APS's current LCA structure (*e.g.,* 15-year terms, financial security requirements, exit or termination penalties, etc.).[14] In addition, Staff witness Anthony Georgis similarly supports the need for long-term contracts, like the LCA, to cover service commitments for data centers and similar large, high load factor customers.[15] Mr. Georgis recommends, however, more stringent terms. State of Arizona witness Caryn Potter also supports the use of long-term contracts with terms that are consistent with the LCA for data centers and other large, high load factor customers.[16] Like Mr. Georgis, Ms. Potter similarly recommends greater stringency to protect APS customers from cost shift risks. Among the parties in this rate case, Phoenix Hydrogen Hub LLC's (PHH) witness Su Lin Ong appears to be the only witness recommending less stringent terms for LCAs and fewer customer protections from cost shifts.[17]

Among these various perspectives, and as described in more detail by Mr. Bauer in his Rebuttal Testimony, APS is seeking to achieve a balance between ensuring

[14] RUCO, Direct Testimony of Dustin Madsen, CPA, CDP, CRRA, CPA (CAN), CA (CAN) (Mar. 18, 2026) at 16.
[15] Staff, Direct Testimony of Anthony Georgis (Mar. 18, 2026) at 27-28.
[16] State of AZ, Direct Testimony of Caryn Potter (Mar. 18, 2026) (Potter Direct) at 11-14.
[17] PHH, Direct Testimony of Su Lin Ong (Mar. 18, 2026) at 8-11.

commercial reasonability for its large customers, while at the same time preventing cost shifts. The current structure of the LCA achieves this balance.

Q. WOULD ANY OF PHH'S PROPOSED CHANGES TO THE LCA NEGATIVELY AFFECT CUSTOMERS?

A. Yes. APS needs the ability to determine what protections and risks need to be managed to ensure financial stability for the Company and ensure its broader customer base is not exposed to undue risk from speculative projects. APS believes the current version of the LCA achieves those goals. As proposed by PHH, the suggested changes to the LCA would have the effect of shifting greater amounts of financial risk onto APS's broader customer base and away from individual large, high load factor customers. As described in more detail by Mr. Bauer, such a shift in risk places undue financial burden on existing APS customers and should be rejected.

Q. WHY IS A TIMEFRAME NECESSARY FOR THE EXECUTION OF THE LCA?

A. The timeframe for developing and executing the LCA contained in APS's Large Customer Project Queue process was established to prevent speculative actors from occupying a queue position without making meaningful progress toward reaching agreement with APS on terms for service that will adequately protect the Company's existing customer base. APS has over 21 GWs of prospective customers in its uncommitted queue, so the timeline established for negotiating and executing the LCA is intended to prevent prospective customers from monetizing or gaming their queue position to the detriment of other prospective customers who would be willing to execute terms that appropriately protect other customers. It is very important to recognize in this context that, as of the filing of this testimony, APS has already had at least three other customers execute the LCA without

concern or complaints as to the legitimacy or viability of its commercial terms; and more are on the way.

Q. IS THE 60-DAY TIMEFRAME FOR NEGOTIATING THE LCA IN APS'S LARGE CUSTOMER PROJECT QUEUE PROCESS A RIGID AND INFLEXIBLE REQUIREMENT?

A. No. In fact, PHH had a draft of APS's LCA for approximately four months before APS informed PHH of the need to operate within the 60-day timeline spelled out in APS's Large Customer Project Queue process. Given the absence of progress negotiating the LCA up to that point, it was appropriate for APS to impose a deadline for execution in order to incentivize progress toward execution of the document. Thereafter, given the progress that had been made during that period, APS extended the timeframe for completing the LCA once the initial 60-day timeframe was exhausted. As such, where meaningful progress on the LCA had been made, APS exercised flexibility and continued negotiating with PHH in good faith.

Q. WHAT HAPPENED AFTER APS EXTENDED THE DEADLINE TO COMPLETE NEGOTIATION OF THE LCA?

A. The parties worked together in good faith to negotiate a mutually workable agreement. As of December 10, 2025, both parties had executed the LCA and thereafter were working on implementing the agreement.

Q. AFTER PHH AGREED TO AND EXECUTED THE LCA, DID IT REMAIN IN EFFECT?

A. No. Notwithstanding APS's willingness to provide additional time for posting the required financial security for the agreement, PHH allowed the LCA to expire by failing to post collateral. These were requirements that, approximately one month earlier, PHH had agreed to when it signed the LCA.

Q. ISN'T IT UNFAIR TO REQUIRE AN LCA FOR A PROSPECTIVE CUSTOMER THAT HAS ALREADY MADE SUBSTANTIAL INVESTMENTS TO DEVELOP A NEW BUSINESS?

A. No. Once APS commits to serve a given large, high load factor customer, the Company will incur significant investments and expenses toward the generation, transmission, and distribution infrastructure necessary to serve that customer. In this situation, had the Company invested in serving this customer, absent the LCA or financial security, the Company's broader customer base would have faced significant risk of absorbing these costs. The LCA, therefore, exists to remedy this imbalance and protect APS's existing customers from the risk of cost shifts.

Q. WHY HAS APS IMPOSED LCA REQUIREMENTS ON LARGE, HIGH LOAD FACTOR CUSTOMERS AT DIFFERENT STAGES OF THEIR DEVELOPMENTS?

A. APS developed the LCA in response to real-time developments within its service territory as a means to protect existing customers from bearing the risk of cost shifts associated with the large infrastructure investments and expenses needed to serve individual large customers. As APS indicated in its discovery responses, the Company began reaching out to its committed prospective customers in November 2024 to begin the process of executing LCAs with customers that were not yet under an existing ESA, PA, or Line Extension Agreement. This was in response to unprecedented load growth the Company had been experiencing and the need to ensure that APS's existing customer base was not subject to the burden of having to incur the costs for infrastructure needed to serve growth that may not necessarily materialize as projected by prospective customers. Given that different customers were in different stages of development when the LCA was introduced, the timing was not the same for each individual customer project.

C. *Future Mechanisms for Enabling Service to New Large Customers*

Q. IN THIS RATE CASE, IS APS PROPOSING ANY OTHER MECHANISMS FOR PROVIDING SERVICE TO LARGE, HIGH LOAD FACTOR CUSTOMERS, SUCH AS A "SUBSCRIPTION" MODEL?

A. No. Apart from the changes to the extra high load factor (XHLF) rate schedule, which are discussed in more detail by APS witness Jessica E. Hobbick in her Direct and Rebuttal Testimonies, APS is not proposing any other mechanisms for providing service to large, high load factor customers as part of this rate case. APS's Subscription Program, which could potentially provide an accelerated basis for providing service to certain large, high load factor customers, remains under development at this time and is, therefore, not at issue in this rate proceeding. No costs, expenses, or investments related to this program are being sought for recovery in this case, nor are any specific terms of service for this program. In general, this mechanism would involve specific Commission approval for the unique terms of service for one or more large, high load factor customers, most likely data centers or high-tech manufacturers. Pursuant to such unique terms of service, the customers would agree to take on their share of all costs associated with developing and operating the new infrastructure (*e.g.,* power plants and transmission lines) necessary to enable their service on an accelerated basis. Once APS has fully developed a proposal for offering such service to a specific customer or customers, the Company will submit an application for approval of a special direct pricing contract with the Commission. As described in more detail by Ms. Hobbick, separate Commission approval is necessary for such service.

Q. WILL A DIRECT PRICING CONTRACT CONTAIN PROVISIONS THAT PREVENT EXISTING CUSTOMERS FROM SUBSIDIZING THE DEVELOPMENT OF NEW INFRASTRUCTURE NEEDED TO SERVE THE PARTIES TO THIS CONTRACT?

A. Yes, absolutely it will. APS generally agrees with Ms. Potter in terms of the necessary protections that must exist within any agreement to serve new large, high load factor customers under a special, direct pricing contract.[18] Such protections should include, without limitation: the posting of financial security or collateral to protect existing customers from the risk of customer defaults; the inclusion of exit or termination fees necessary to prevent the incurrence of stranded costs; requirements for the customers to provide payment for 100% of their share of all necessary incremental infrastructure investment costs (generation, transmission, and distribution) necessary to enable their service, coupled with all ongoing operations, maintenance, and other fixed and variable expenses associated with these investments; minimum contract terms, subject to renewal; and appropriate minimum demand and energy charges to address risks of delays in customer development.

Q. IS IT NECESSARY FOR THE COMMISSION TO APPROVE THESE EXACT TERMS NOW?

A. No. At this time, if the Commission were to consider the recommendations offered by Ms. Potter, the Commission would be essentially determining the terms of service for a specific future large customer entirely in the abstract. More importantly, once APS has developed a specific proposal for unique service of the kind described here, the Company will submit an application to the Commission for review and approval of any governing terms and conditions, along with supporting financial schedules. That process will ensure a robust and transparent

[18] Potter Direct at 13-14.

review process, including external stakeholder review and participation, to ensure that no such provision of service creates cost shifts or risks to service reliability.

VIII. TRANSMISSION AND DISTRIBUTION PLANNING

Q. HOW DOES THE COMPANY PLAN ITS TRANSMISSION SYSTEM?

A. APS plans its transmission system through a structured and repeatable process that integrates long-term system planning with a formal capital project development framework. The Company develops and maintains a Ten-Year Transmission Plan that evaluates transmission system performance over a long-range planning horizon under normal and contingency conditions, consistent with applicable reliability criteria. Similar to APS's IRP process for identifying necessary generation resources to reliably serve customers over a 15-year time horizon, APS's Ten-Year Transmission Plan is subject to review and rigorous scrutiny by the Commission. APS similarly provides a Biennial Transmission Assessment (BTA) for review and oversight by the Commission. These planning studies identify emerging system limitations, reliability risks, and future needs driven by changes in load, generation, and system conditions, and they form the analytical foundation for potential transmission solutions.

Q. HAS THE FERC FORMULA RATE LED THE COMPANY TO MAKE UNNECESSARY TRANSMISSION INVESTMENTS?

A. No. Before the Company makes any decisions to initiate a capital project, the teams responsible for transmission planning define a specific system problem or need arising from the planning process and evaluate potential alternatives capable of addressing that need. Projects may be driven by forecasted load growth, reliability or operational concerns, interconnection requirements, or compliance obligations. Alternatives are reviewed, which could include system upgrades, non-wires solutions, and/or new transmission facilities, and a preferred solution is selected

based on its ability to resolve the identified issue in a cost-effective manner, prior to initiating capital project approval activities.

Transmission projects that proceed beyond the planning phase are developed and approved through defined stage-gate reviews and, once approved, are incorporated into the Company's long-range forecast and annual capital planning process. This approach ensures that transmission investments are supported by documented planning analysis, evaluated consistently, and aligned with long-term system needs. Given the Commission's review of the APS BTA and the Ten-Year Transmission Plan, this process is also subject to rigorous regulatory oversight. Through this integrated planning and capital development framework, APS seeks to maintain a reliable transmission system while making prudent, forward-looking infrastructure investments that are cost effective and in the best interest of APS customers. In other words, the form or method of cost recovery for APS transmission projects has no bearing on how APS plans, designs, and implements transmission line improvements.

Q. DOES THE INFORMATION CONTAINED WITHIN INDIVIDUAL FERC FORM 1 FILINGS PROVIDE A COMPLETE PICTURE OF THE TOTAL TRANSMISSION LINE MILEAGE IN WHICH APS HAS INVESTED THAT ARE SUPPORTED BY A FERC FORMULA RATE?

A. No. The total miles of transmission reflected across APS's FERC Form 1 – Electric Utility Annual Report filings include both miles added to the system but also lines that have been retired, infrastructure that has been sold, and periodic data revisions. When evaluating APS's collective FERC Form 1 filings between 2011 and 2024,[19] the data demonstrates that APS has added approximately 485 miles of new

[19] This data is provided within the "Important Changes during the Quarter/Year" section of APS's FERC Form 1.

transmission lines (69kV – 500kV) over this period. These projects have delivered significant benefits to customers.

During this period, in addition to APS investments in new transmission lines, several initiatives were specifically aimed at ensuring the Bulk Electric System operates reliably and avoids overloading. These upgrades to existing facilities maintain compliance with applicable regulatory standards and also make the APS owned transmission system significantly reliable and safe for APS customers. Other projects during this period focused on upgrading the system to increase capacity to deliver power to customers. For example, this included upgrading the high-pressure fluid filled underground 230kV system that serves the City of Phoenix. This project increased the capacity of the lines and improved the reliability of the system. APS also serves rural communities, such as the communities near, and even within the Grand Canyon. APS upgraded the Grand Canyon-Williams 69kV line in order to serve increased customer demand from these APS customers. These and other similar transmission projects expand APS's capability to serve customers reliably across the state. Additionally, APS continually enhances the transmission network to facilitate the integration of new generation sources, ultimately supporting the reliable delivery of electricity to those the Company serves.

Q. HOW DOES THE COMPANY PLAN FOR DISTRIBUTION SYSTEM INVESTMENTS AND MAINTENANCE?

A. APS plans and prioritizes distribution system investments and maintenance through a comprehensive, data-driven process designed to ensure safe, reliable, and affordable electric service across its service territory. This planning approach balances current system needs with long-term growth projections.

APS conducts annual assessments of customer infrastructure and energy needs across its territory. As part of this process, APS evaluates actual system loading conditions, customer growth trends, and various other factors to identify current and potential future constraints on the APS system. APS begins by identifying minimal cost solutions such as transferring load between feeders and substations. Additional solutions are then identified, which may include improvements to feeders, substations, and associated infrastructure. These assessments evaluate feeder and substation annual peak load and allow APS to proactively address capacity and reliability constraints before they impact customers.

Additionally, APS collaborates with customers, developers, municipalities, and internal planning teams to assess future growth needs and develop solutions to align project timelines to support growth efficiently. These collaborative efforts minimize service delays, reduce costs, and support economic development while maintaining system reliability. Investment prioritization is guided by a structured framework that places safety, reliability, and affordability at the forefront of decision making.

Q. WOULD THE METHOD OF COST RECOVERY AFFECT HOW THE SYSTEM IS PLANNED AND MAINTAINED?

A. No. Similar to how the Company plans for necessary infrastructure investments in the generation and transmission spaces, distribution system planning, development, and operation is solely driven by current and future customer needs. As such, the method or means of cost recovery for these costs has no influence whatsoever as to distribution system planning, development, or operation.

IX. COAL COMMUNITY TRANSITION

Q. IS THE COMPANY REQUESTING CCT FUNDING IN THIS RATE CASE?

A. No. APS agrees with the Navajo Nation's statement in its application to intervene in this proceeding that states "CCT assistance goes beyond ratepayer funded CCT assistance" and that "the most effective CCT assistance builds capacity for the Nation to pursue energy sovereignty . . . ."[20] As represented in the intervention filing, APS and the Nation continue to "…negotiat[e] amendments to the CCT Agreement that will not include ratepayer funded CCT assistance subject to the Commission's approval." [21] Discussions between APS and the Navajo Nation remain ongoing at this time and the Company cannot predict the outcome or timing for any resolution.

Q. DID INTERVENORS PROVIDE TESTIMONY RELATED TO CCT?

A. Yes. The San Juan Citizens Alliance and Tó Nizhóni Ání (Citizen Groups) recommend that the Commission approve the ratepayer funded CCT assistance that was not approved in Decision No. 78317.[22] [23] Additionally, the Citizen Groups recommended that APS and other utilities develop new clean energy capacity on tribal lands.

[20] Application of Navajo Nation for Leave to Intervene and Consent to Email Service, Docket No. E-01345A-25-0105 (Nov. 3, 2025) at 2.

[21] *Id.*

[22] Citizen Groups, Direct Testimony of Nicole Horseherder (Mar. 2, 2026) at 29-30.

[23] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Prop. for Ratemaking Purposes*, Docket No. E-01345A-19-0236, Decision No. 78317 (Nov. 9, 2021).

Q. REGARDING CITIZEN GROUPS' RECOMMENDATION, IS APS WORKING TO SUPPORT THE DEVELOPMENT OF NEW ENERGY CAPACITY ON TRIBAL LANDS?

A. Yes. The CCT Agreement between APS and the Navajo Nation contained a number of provisions upon which APS has made significant progress, including APS's provision of financial support from shareholders, job redeployment for APS employees at coal-fired power plants at the time they cease operation, support for tribal water rights efforts, and material support for electrifying homes and businesses within the Hopi and Navajo Nation reservations. It also requires APS to issue two sets of requests for proposals concerning Tribal Renewable Energy Projects. The first set was to seek one or more location-targeted proposals seeking to procure at least 250 MW of renewable electricity generation capacity to be constructed within the geographic boundaries of the Navajo Nation with the intent to deliver electricity to APS customers. APS has continued to seek such proposals as part of its 2023, 2024, and 2025 ASRFPs. The second set of Request for Proposals will be released over a period of 12 months after APS ceases reliance upon the Four Corners Power Plant (Four Corners) for power generation. APS remains committed to this procurement activity that supports the future development of renewable resources within the Navajo Nation.

Q. GIVEN THE REQUIREMENTS IN APS'S CCT AGREEMENT WITH THE NAVAJO NATION, WHY HASN'T APS PUT FORTH ANOTHER REQUEST IN THIS RATE CASE FOR SUCH FINANCIAL ASSISTANCE?

A. As discussed above, APS and the Navajo Nation are currently working to develop an alternative to the current CCT Agreement through one or more amendments to the existing contract. As stated by the Navajo Nation, this amended agreement would seek to "go [] beyond ratepayer funded CCT assistance" and focus instead on other means of support that do not depend on APS customer funding. In light of

APS's and the Navajo Nation's ongoing discussions aimed at amending the current CCT Agreement, an additional request for customer-funded CCT financial assistance is not appropriate at this time.

In addition, APS is currently in the process of evaluating continued operations at Four Corners beyond 2031. While it remains unclear at this time whether or what form such continued operations would take, continued operations at Four Corners would subvert the fundamental premise of the current CCT Agreement. This current process, therefore, calls into question the near-term need for APS to provide additional CCT support for the Navajo Nation.

X. DEMAND SIDE MANAGEMENT

Q. SOUTHWESTERN ENERGY EFFICIENCY PROJECT (SWEEP) WITNESS WILL GREENE SUGGESTS EXPANSIONS OF VIRTUAL POWER PLANT (VPP) OFFERINGS AND GREATER EMPHASIS ON "PAY FOR PERFORMANCE" CUSTOMER INCENTIVES. HOW DO YOU RESPOND?

A. Consistent with the overall direction of APS's demand-side management (DSM) programs in recent years, APS supports continued expansion of the Company's VPP program offerings. In general, VPP programs offers dispatchable demand response measures that provides real-time access to capacity and energy savings based on interconnected home devices and large appliances (*e.g.,* web interconnected thermostats, in-home battery energy storage systems, etc.). APS agrees with SWEEP that expanding these programs to additional energy-savings opportunities is an effective means of developing greater demand response capacity.[24]

[24] SWEEP, Direct Testimony of Will Greene (Mar. 18, 2026) at 32-34.

APS also agrees that it is appropriate for the Company to evaluate new incentive structures for incorporation into existing and expanded DSM programs to ensure they are directly linked to actual delivered energy savings.

As to both, APS believes it is appropriate for these measures to be considered as part of the Company's existing DSM stakeholder collaborative process. This would be an effective forum to further consider these opportunities and develop them for potential inclusion within future APS DSM implementation plans.

XI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Information Technology and Facilities
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
1	Data Analytics	Provide dynamic predictive risk and asset failure models to facilitate data driven decisions for maintenance, inspection, capital planning, and replacement.	Q1 - 2025	$ 4,046,304
2	Application Sustainability	Support and maintain application upgrades needed to ensure software is kept up to date.	Q3 - 2025	$ 27,922,874
3	Corporate Modifications	Support modification and renovation projects to reconfigure and remodel of work spaces to accommodate business needs.	Q4 - 2025	$ 4,545,149
4	Facilities Run Maintain-Building	Planned predictive replacements of foundations, walls, roofs, ceilings, stairs, floor coverings, windows, plumbing and fixtures, built-ins, office lighting, conventional doors and partitions, decorations, and modular trailer buildings	Q4 - 2025	$ 5,912,806
5	Facilities Run Maintain-HVAC	Planned predictive replacements of HVAC (heating, ventilation, and air conditioning) equipment/components	Q3 - 2025	$ 1,189,312
6	aps.com Security Improvements	Enhance the security and resilience of the aps.com website against malicious bot attacks.	Q2 - 2025	$ 296,712
7	Audio Visual (AV) Sustainability Project	Update or add conference room audio visual equipment and workstation IT peripherals at APS facilities.	Q2 - 2025	$ 2,154,855
8	High Bill Analyzer	Implement a new product that enables the Customer Experience Center to serve high bill calls from customers.	Q3 - 2025	$ 4,489,159
9	CHQ Electrical Infrastructure	Replace electrical infrastructure replacement for Life, Fire & Safety systems per City of Phoenix code compliance	Q4 - 2025	$ 10,711,554
10	Client Applications	Ensures Windows workstation operating systems and back office applications are kept secure at a supported level while adding functionality to improve business productivity	Q4 - 2025	$ 1,117,307
11	Computer Upgrades	Compute program projects drive the modernization of Identity & Access Management, Virtual Compute Infrastructure, and server lifecycle management. These efforts strengthen IT security, enhance system reliability, and support business continuity at APS.	Q3 - 2025	$ 4,635,323
12	Customer Lifecycle Construction Project	Improve the business process of receiving and managing construction requests from customers.	Q2 - 2025	$ 3,318,580
13	Consumer App Redesign	Rewrite the aps.com mobile app on the ReactNative framework.	Q2 - 2025	$ 1,486,012
14	Customer Outage Notifications	Enhance Outage Communications to improve the overall outage experience for APS Residential and Business customers while improving internal system and process efficiencies.	Q2 - 2025	$ 1,350,545
15	Dallas Security Software Access Control System Replacement	Enterprise-wide replacement of Dallas Security Software Access Control System.	Q4 - 2025	$ 1,614,562
16	Deer Valley N1 and N2 Uninterruptiple Power System Replacement	Uninterruptible Power System replacement for Deer Valley buildings N1 and N2	Q4 - 2025	$ 2,279,948

Information Technology and Facilities
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
17	Enterprise Asset Management System	Enterprise Asset Management System project to improve business functionality on applications including but not limited to Maximo, Zycus, Site Work Management System, Business Intelligence/Reporting, and Beeline	Q3 - 2025	$ 4,975,007
18	Electric Vehicle (EV) Charging	Provide adequate Electric Vehicle (EV) charging infrastructure for all employees onsite statewide.	Q2 - 2025	$ 1,195,432
19	Generation Monitoring & Diagnostics Center	Create models and implement a Monitoring and Diagnostics center.	Q4 - 2025	$ 7,036,114
20	Transportation Shop Equipment	Replacement of shop lifts used to perform under the hood work.	Q3 - 2025	$ 1,433,725
21	Lease Buyouts on Equipment	Purchase of APS vehicles at the end of their lease term.	Q4 - 2025	$ 3,873,053
22	License Renewal	Renewal of hardware and software licenses related to design, construction, backup server, enhanced aps.com search engine capabilities and customer experience management.	Q2 - 2025	$ 44,183,786
23	Information Security & Compliance Obsolescence	The replacement of outdated, unsupported, and/or no longer effective systems. The purpose of the Security Program is to ensure the critical systems we rely on are functional, supported and operational.	Q4 - 2025	$ 2,618,334
24	ITRON Upgrade	Upgrade ITRON Field Service Collection software and hardware. ITRON supports APS' non-AMI meters statewide by gathering meter reads/interval data, and providing meter events, status, and instrumentation data.	Q4 - 2025	$ 862,250
25	Local Area Network	Replace end of line/non-scalable routers, decommission Corporate Security and Smart Grid firewalls.	Q2 - 2025	$ 3,959,717
26	Maximo Platform Upgrade	Transition the Company onto Maximo Application Suite version 9 from the Company's current version of Maximo 7.6.1.2.	Q4 - 2025	$ 6,477,836
27	Modernize Email Security	Evaluate and implement best practice configurations for securing on-premise exchange, mailhub, domain protection, advance phishing protection and email security.	Q3 - 2025	$ 920,588
28	Monitoring Systems	Employ advanced monitoring systems to ensure reliable business operations and avoid IT system outages.	Q4 - 2025	$ 16,449,367
29	Organized Market Transformation	Support APS's participation in organized energy markets and programs (EIM, new day ahead markets, WRAP).	Q3 - 2025	$ 2,014,246
30	Laptop Purchase Program	Buyout expiring leased computers and move to a purchase model.	Q4 - 2025	$ 5,682,621
31	Physical Security System Program	Replace Physical Security hardware for video recorders, cameras, intrusion detection, and call/false alarm reduction.	Q1 - 2025	$ 3,324,158
32	Physical Security Upgrade	Upgrade gate access hardware at Deer Valley.	Q1 - 2025	$ 185,148
33	Power Purchase Agreement Implementations	Integrate systems to enable dispatch of seven new power purchase agreement facilities.	Q4 - 2025	$ 2,581,364
34	ServiceNow	Upgrade ServiceNow’s capabilities across multiple enterprise functions to improve operational efficiency, reduce manual processes, and foster automation, helping APS deliver faster and more reliable service to customers.	Q2 - 2025	$ 1,756,098

Information Technology and Facilities
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
35	Storage Disks	Additional disks for organic data growth, memory & central processing unit (CPU) to improve performance, and manage and protect data	Q1 - 2025	$ 8,032,622
36	Distribution Communications Upgrades	Implement, replace, or upgrade communication infrastructure to support Distribution Advanced Grid Technology Power Quality and Reliability programs, including Fire Mitigation plans.	Q1 - 2025	$ 3,675,532
37	Unified Communications Program	Replace the equipment servicing the Enterprise Voice and Wireless infrastructure.	Q2 - 2025	$ 1,922,287
38	User Access Validation Replacement	Replacement system for Critical Infrastructure Protection (CIP)-required review and validation of physical and electronic access to High and Medium CIP cites	Q3 - 2025	$ 317,971
39	Wide Area Network	Provide increased bandwidth for statewide licensed microwave communications installations. Replacements for serial multiplexers and microwave radio and supporting power systems.	Q2 - 2025	$ 10,755,768
40	Customer Experience Program - 2024	Customer Experience improvements to improve customer and employee experience.	Q2 - 2025	$ 6,027,097
41	Customer Experience Upgrade Projects	Technology solution to improve customer experience by communicating with customers in a more timely manner through the method of their preference.	Q4 - 2025	$ 418,584
42	C&I Level 2 Charging	Provide Level 2 equipment and/or infrastructure for EV charging for workplace, fleet and multi-family.	Q3 - 2025	$ 1,479,504
43	Hubwest Pole Bunkers	Bunkers for utility poles	Q1 - 2025	$ 726,147
44	Digital Transformation	Empower the organization with a unified, intelligent, and scalable data platform that drives actionable insights, fosters innovation, and supports data-driven decision-making across all business units.	Q3 - 2025	$ 4,936,638
45	Kofax Transformation Module Upgrade	Upgrade Kofax Transformation Module (KTM) so that it is compatible with Windows 11.	Q4 - 2025	$ 227,391
46	Risk Management System Replacement	This project will replace Riskonnect with an Archer software product for the Risk and Insurance Management team, as the current software does not meet APS standards for service and quality due to data usage issues and unaddressed issues.	Q4 - 2025	$ 250,118
47	IT and Facilities Trailing Charges	Trailing charges for projects in-service in previous periods		$ (9,968,920)
48	**Total IT & Facilities**			**$ 215,400,583**

Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
1	Spray Pond Piping Replacement	The scope of this project will replace the Essential Spray Pond piping in all three units.	Q4 - 2025	$ 1,107,922
2	Balance of Plant (BOP) Engineered Safety Features Actuation System (ESFAS) Cabinet Replacement in Common Unit CK4	The scope of this project is to reverse engineer the existing BOP ESFAS system with current components and techniques. All modules in the BOP ESFAS cabinet will be replaced.	Q2 - 2025	$ 1,580,073
3	Refurbish Cooling Tower Valve Pits	The scope of structural rebuild is well-defined and can be implemented with minimal engineering effort, but consideration is being given to relocate the LV22 control valve and line above ground.	Q4 - 2025	$ 1,061,361
4	Water Resources Admin Building Remodel	The purpose of this project is to make necessary upgrades to the water resources building.	Q2 - 2025	$ 396,810
5	Sentinel Upgrade	Sentinel is a RP software tool and needs to be upgraded as it is no longer supported.	Q3 - 2025	$ 178,911
6	Valve Replacements Unit 1	Replacement of valves to protect plant equipment and increase equipment availability.	Q2 - 2025	$ (9,064)
7	Switchgear Condition Monitoring U1 NBNS02	The scope of this project will be to incorporate vibration sensors and Motor Current Signature Analysis sensors on select equipment	Q2 - 2025	$ 128,927
8	Normal Chiller Replacement Unit 3	Project scope is the replacement of all small Normal Chillers with a "Chiller Farm" Modular Chiller Plant. Current Chillers are obsolete and no longer supported by the vendor.	Q4 - 2025	$ 9,762,903
9	Instrumentation & Controls Unit 3	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the site. Examples of this include annunciators, capacitators, control systems, fuses, receivers, transmitters, etc. These devices and more saw dramatic reductions in the materiality qualification for capitalization with the RUC change. The scope of this project includes RUC qualifying, I&C and Electrical materials and installation.	Q4 - 2025	$ 29,079
10	Site Work Management System Forms Phase 1	Migration of old Oracle Form based screens in SWMS to interactive web technology – Phase 1	Q1 - 2025	$ 112,487
11	Digital Strategic Modernization Program (SMP) Phase 2 Unit 2	The Strategic Modernization Program (SMP) will replace several plant control systems, both analog and digital with newly designed and upgraded equipment. The intention of this upgrade is to address obsolescence, remove single point vulnerabilities where practical, improve Human-Machines interfaces, and minimize spare part inventories.	Q4 - 2025	$ (1,641,784)
12	Data Analytics	At present, production of many of the site metrics is manual, cumbersome, and time-consuming. The scope of this project is to automate gathering and reporting (including analysis) of data used in site metrics to improve management information available to Senior Management and reduce labor hours.	Q2 - 2025	$ 69,593
13	Water Resources Tools & Equipment	Various tools and equipment are used throughout the site for repair work, testing, and other general uses to deliver high quality of work. The scope of this project is for the purchase and replacement of site tools and equipment.	Q1 - 2025	$ 118,907

Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
14	Water Resources Instrumentation & Controls Equipment Replacement	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the Water Resources Facility. The scope of this project includes RUC qualifying, I&C and Electrical materials and installation.	Q1 - 2025	$ 60,255
15	Water Resources Valve Replacements	Periodically replacements of valves/valve internals are required due to degradation/failure. At Water Resources, valves are treated as run to failure components, and replaced when this occurs. The scope of this WA includes the replacement of all valves and valve internals at Water Resources whose characteristics and cost align them with the RUC	Q1 - 2025	$ 96,856
16	Small Scale Water Resources Projects 2024	To maintain continuous operation at Palo Verde Water Resources, there are a number of small projects that go on throughout the year. Examples of this includes expansion joint replacements, or cathodic protection anode bed replacements. The scope of this project includes RUC qualifying, minor projects at Water Resources.	Q4 - 2025	$ 74,447
17	Motor Current Signature Analysis (MCSA)	The scope of this project will be to incorporate vibration sensors and Motor Current Signature Analysis sensors on select equipment	Q4 - 2025	$ 132,560
18	Cathodic Protection	Ongoing replacement of failed anodes and support devices employed in the Cathodic Protection System.	Q1 - 2025	$ 281,156
19	Site Tools & Equipment	This project allows the site to purchase and replace old tools and equipment that are unreliable and obsolete with improved and safer models of tools.	Q1 - 2025	$ 487,695
20	Security Tools & Equipment	This project is for purchase and replacement of unreliable and obsolete Security tools and equipment for search trains, facilities, firing range, officer gear, etc.	Q1 - 2025	$ 101,631
21	Nuclear Fuels Management Software	The purpose of this project is for Interactive Special Nuclear Material (SNM) tool that is part of the long-term strategy for reduction of human performance error-prone and/or repetitive activities.	Q2 - 2025	$ 44,673
22	Horizontal Pumping System Pumps Replacement	The purpose of the project is to replace the two remaining carbon steel Pumping Station pumps Pumping Station NP02A/B with stainless steel pumps.	Q3 - 2025	$ 252,071
23	Digital Strategic Modernization Program (SMP) Phase 3 Simulator A	The Strategic Modernization Program (SMP) will replace several plant control systems, both analog and digital with newly designed and upgraded equipment. The intention of this upgrade is to address obsolescence, remove single point vulnerabilities where practical, improve Human-Machines interfaces, and minimize spare part inventories.	Q2 - 2025	$ 317,947
24	Facility Building A Remodel	The scope of this project to remodel Building A.	Q4 - 2025	$ 3,645,443
25	Facility Building Outage Service Building Unit 2 Remodel	The scope of this project is to remodel Building OSB U2 level 1&2.	Q1 - 2025	$ 324,216
26	HVAC Replacement Simulators A & B	The scope of this project is to replace failed/failing HVAC units in the A & B Simulators to keep work areas habitable.	Q1 - 2025	$ 423,170
27	HVAC REPLACEMENTS Operations Computer Systems	The scope of this project is to replace failed/failing HVAC units in the OCS to keep work areas habitable.	Q1 - 2025	$ 125,782
28	Add Non-Segregated Bus to NB-1772	Based on water intrusion issues, which challenged the Essential Safety Function (ESF) transformers operability, need to add Non-Segregated Bus scope to the NB 1772 modification's scope.	Q2 - 2025	$ 731,693

Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
29	Pressurizer Heater Replacement	To replace the pressurizer heater that is nearing end of useful life.	Q4 - 2025	$ 21,460
30	Digitizing Nuclear Records	PURCHASE 3 NEXTSCAN MACHINES TO SUPPORT DIGITAL CONVERSION	Q2 - 2025	$ 91,421
31	Auto Electronic Defibrillators Replacement	AUTO ELECTRONIC DEFIBRILLATORS (AED) REPLACEMENT	Q1 - 2025	$ 37,033
32	Motor Replacements Unit 1	Replacement of Motors to prevent unplanned outages.	Q2 - 2025	$ 613,910
33	Motor Replacements Unit 3	Replacement of Motors to prevent unplanned outages.	Q4 - 2025	$ 160,871
34	Motor Replacements Unit 2	Replacement of Motors to prevent unplanned outages.	Q4 - 2025	$ 65,798
35	Valve Replacements Unit 2	Replacement of valves both emergently and per the long-range Plan with the purpose of protecting plant equipment and increasing equipment availability.	Q4 - 2025	$ 296,994
36	Circulating Water System Pipeline Replacement 2025	The Circulating Water System Piping consists of piping from the Circulating Water Pumps to the Main Condenser and the Main Condenser to the Main Cooling Towers. It also includes the pipelines conveying blow down from the Circulatin Water System to the Evap Ponds. This project takes a proactive approach to addressing known degraded condition and repairs pipe based off of inspection results	Q4 - 2025	$ 1,285,182
37	Small Scale Water Resources Projects 2025	To maintain continuous operation at Palo Verde Water Resources, there are a number of small projects that go on throughout the year. Examples of this includes expansion joint replacements, or cathodic protection anode bed replacements. The scope of this project includes Retirement Unit Catalog qualifying, minor projects at Water Resources.	Q4 - 2025	$ 122,771
38	Cooling Towers Life Extension Unit 1	The scope of this project is replacement of structural components in the cooling towers to improve their operational efficiency, structural integrity, and extend their lives.	Q2 - 2025	$ 3,063,136
39	Motor Replacements Unit 1 & 3	Replacement of Motors to prevent unplanned outages.	Q4 - 2025	$ 83,655
40	Valve Replacements Unit 1	Replacement of valves both emergently and per the Long-Range Plan with the purpose of protecting plant equipment and increasing equipment availability.	Q4 - 2025	$ 232,014
41	Reactor Coolant Pressurizer Nozzle	The TE-101 pressurizer nozzle will be entirely removed and substituted with a novel alloy 690 nozzle and weld material in order to rectify the through wall leak in the RCS. This substitution will reinstate the integrity of the RCS system, minimize the likelihood of future leakage at this nozzle, and facilitate obtaining approval from the NRC to recommence operations	Q2 - 2025	$ 4,832,270
42	Digital Strategic Modernization Program Phase III Unit 3	Replacement of degraded concrete components of the spray pond structures. The spray ponds are approximately 30 years old with cracks in the concrete requiring replacement to ensure long-term safe operation.	Q4 - 2025	$ 22,774,252
43	Control Oil (CO) Duplex Pump & Filter	The projects main action is to modify the system to allow CO filter replacement without creating a conditional single point vulnerability (SPV) thus increasing system reliability and reduce risk associated with online filter replacements. Current CO system design contains main filters downstream of the CO pumps. When filters require replacement online, the affected train is tagged out for maintenance to allow for filter replacement, and the opposite train becomes unavailable for standby operation, thereby becoming a conditional single point vulnerability (SPV) for the unit.	Q4 - 2025	$ 2,100,158

Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
44	Instrumentation, Controls, and Electrical Unit 1 2025 Online	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the site. Examples of this include annunciators, capacitators, control systems, fuses, receivers, transmitters, etc. These devices and more saw dramatic reductions in the materiality qualification for capitalization with the retirement unit catalog change. The scope of this project includes retirement unit catalog qualifying, Instruments, controls, and electrical materials and installation.	Q4 - 2025	$ 167,232
45	Circulating Water Pump Pit Unit 1	The scope of this project will replace degraded concrete in circulating water pump pit.	Q2 - 2025	$ 309,939
46	I&C and Electrical Unit 1 2025 Outage	During refueling outage, various instrumentation, controls, and electrical equipment are used/replaced throughout the site. Examples of this include annunciators, capacitators, control systems, fuses, receivers, transmitters, etc. These devices and more saw dramatic reductions in the materiality qualification for capitalization with the retirement unit catalog change. The scope of this project includes retirement unit catalog qualifying, instruments, controls, and electrical materials and installation.	Q2 - 2025	$ 762,045
47	Valve Replacements Unit 1 2025 Outage	Replacement of valves per the long-range plan with the purpose of protecting plant equipment and increasing equipment availability.	Q2 - 2025	$ 2,185,354
48	Turbine Valves Unit 1 2025	The scope of this project is to replace turbine valves according to the long-range plan to maintain the reliability of the valves.	Q2 - 2025	$ 359,937
49	Secondary Vessel Reline Unit 1 2025	The scope of this project is to reline regen vessels according to the long-range plan during the refueling outage work window.	Q2 - 2025	$ 138,880
50	Minor Material Projects 2025 Unit 1	Replace qualifying minor projects, such as expansion joint replacements within pipe, or cable replacements.	Q4 - 2025	$ 40,735
51	Reactor Vessel Head O-Ring Unit 1 Refueling Outage R25	Replacement of inner and outer O-rings each time the reactor vessel closure head is removed to prevent unplanned outages.	Q2 - 2025	$ 44,078
52	Switchgear Condition Monitoring Unit 1	The scope of this project will be to incorporate vibration sensors and motor current signature analysis sensors on select equipment	Q2 - 2025	$ 270,422
53	Cooling Tower Life Extension Fans Unit 1	Replace the current cooling tower fan assemblies with re-designed and modernized fan assemblies. The new design is more resilient and cost effective.	Q2 - 2025	$ 1,365,178
54	Charging Pump Dampener Unit 1	The purpose of this project is to replace the existing gas filled discharge pulsation dampener with a water-filled dampener. This replacement is recommended since the current design requires maintenance and adjustments during outages. The gas-filled design also introduces gas-intrusion vulnerability.	Q3 - 2025	$ 1,971,060
55	Spray Pond Piping Replacement Unit 1	The scope of this project is to replace the essential spray pond piping in unit 1.	Q2 - 2025	$ 2,270,476
56	Reactor Coolant Pump Seal Replacements Units 1 2025	The scope of this project is replacement of the reactor coolant pump seals according to the long-range plan during outages.	Q2 - 2025	$ 170,808
57	Circuit Breaker Replacement Unit 1 2025	Replacement and rebuild of circuit breakers to maintain and protect plant equipment and increase equipment availability.	Q2 - 2025	$ 163,531
58	PB/NB Bus Major Inspection 1R25	The scope of this project will be switchgear major replacements of primary disconnect assembly, elevating mechanisms and current transformers.	Q2 - 2025	$ 457,161

Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
59	Pump Replacements Unit 1 2025 Outage	The scope of this project is to replace pumps according to the long-range plan to maintain the reliability of the pumps.	Q2 - 2025	$ 548,883
60	Heat Junction Thermal Couple Replacement Unit 1	Replace identified degraded heated junction thermal couple (HJTC) in unit 1.	Q2 - 2025	$ 116,119
61	Condition Monitoring Motor Current Signature Aanalysis Unit 1	The scope of this project is to install motor current signature analysis continuous online monitoring for cooling tower fan motors. This project will improve equipment reliability and corrective maintenance while optimizing preventative maintenance.	Q2 - 2025	$ 469,597
62	Main Condensor Expansion Joints Unit 1 2025	Replacement of main condenser expansion joints according to the long-range plan to keep the plant running safely and efficiently.	Q2 - 2025	$ 24,513
63	Flow Accelerated Corrosion Mod Unit 1 2025	Replacement of pipe damaged by flow accelerated corrosion (FAC) according to routine inspections.	Q2 - 2025	$ 45,146
64	Pump Replacements Unit 2 2025 Online	The scope of this project is to replace pumps according to the long-range plan to maintain the reliability of the pumps.	Q4 - 2025	$ 195,671
65	Instrumentation Controls and Electrical Unit 2 2025 Online	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the site. Examples of this include annunciators, capacitators, control systems, fuses, receivers, transmitters, etc. These devices and more saw dramatic reductions in the materiality qualification for capitalization with the retirement unit catalog change. The scope of this project includes retirement unit catalog qualifying, instruments, controls, and electrical materials and installation.	Q4 - 2025	$ 136,295
66	Circuit Breaker Replacement Unit 2 2025	Replacement and rebuild of circuit breakers to maintain and protect plant equipment and increase equipment availability.	Q4 - 2025	$ 69,728
67	Facility Building Remodel Outage Support Building 2025	The scope of this project to remodel the Outage Support Building to remain in compliance with the Defence Nuclear Facility Safety Board guidelines.	Q4 - 2025	$ 314,117
68	Valve Replacements Unit 3 2025 Online	Replacement of valves both emergently and per the long-range plan with the purpose of protecting plant equipment and increasing equipment availability.	Q4 - 2025	$ 180,014
69	Circuit Breaker Replacement Unit 3 2025	Replacement and rebuild of circuit breakers to maintain and protect plant equipment and increase equipment availability.	Q4 - 2025	$ 53,984
70	Cooling Tower Life Extension 2025 Unit 3	The scope of this project is replacement of structural components in the cooling towers to improve their operational efficiency, structural integrity, and extend their lives.	Q4 - 2025	$ 2,838,436
71	Spray Pond Piping Replacement Unit 3	The scope of this project is to replace the essential spray pond piping in unit 3	Q4 - 2025	$ 696,390
72	Normal Service Transformer Replacement NBNX02 Class Unit 3	The normal service transformers convert non-class 1E, 13.8 kV power to 4.16 kV non-class 1E power. This project will replace the normal service transformers per the long-range plan.	Q4 - 2025	$ 553,211
73	Reactor Vessel Head O-Ring Unit 3 Refueling Outage R25	Replacement of inner and outer O-rings each time the reactor vessel closure head is removed to prevent unplanned outages.	Q4 - 2025	$ 90,336

Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
74	NB 1772 Addition Non-Segregated Bus Unit 3	Based on water intrusion issues, which challenged the essential safety function (ESF) transformers operability, need to add non-segregated bus scope to the NB 1772 modification's scope.	Q4 - 2025	$ 382,644
75	PB/NB Bus Major Inspection Unit 3 R25 Refueling Outage	The scope of this project is switchgear major replacements of primary disconnect assembly, elevating mechanisms and current transformers.	Q4 - 2025	$ 3,176,670
76	Cooling Tower Life Extension Unit 3	The scope of this project is replacement of structural components in the cooling towers to improve their operational efficiency, structural integrity, and extend their lives.	Q4 - 2025	$ 1,283,799
77	Pump Replacements Unit 3 2025 Online	The scope of this project is to replace pumps according to the long range plan to maintain the reliability of the pumps.	Q4 - 2025	$ 37,340
78	Pump Replacements Unit 3 2025 Outage	The scope of this project is to replace pumps according to the long range plan to maintain the reliability of the pumps.	Q4 - 2025	$ 241,587
79	Generator Core Monitor Replacement Unit 3	Replace the generator core monitor on unit 3 with a new model that will increase reliability with improved identification of overheating.	Q4 - 2025	$ 208,461
80	Secondary Vessel Reline Unit 3 2025	The scope of this project is to reline regen vessels according to the long-range plan during the refueling outage work window.	Q4 - 2025	$ 106,767
81	Charging Pump Dampener Unit 3	The purpose of this project is to replace the existing gas filled discharge pulsation dampener with a water-filled dampener. This replacement is recommended since the current design requires maintenance and adjustments during outages. The gas-filled design also introduces gas-intrusion vulnerability.	Q3 - 2025	$ 929,259
82	Valve Replacements Unit 3 2025 Outage	Replacement of valves per the long-range plan with the purpose of protecting plant equipment and increasing equipment availability.	Q4 - 2025	$ 1,711,674
83	Instrumentation & Controls and Electrical Unit 3 2025 Online	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the site. Examples of this include annunciators, capacitators, control systems, fuses, receivers, transmitters, etc. These devices and more saw dramatic reductions in the materiality qualification for capitalization with the retirement unit catalog change. The scope of this project includes retirement unit catalog qualifying, instruments, controls, and electrical materials and installation.	Q4 - 2025	$ 140,527
84	Minor Material Projects 2025 Unit 3	Replacement qualifying minor projects, such as expansion joint replacements within pipe, or cable replacements.	Q4 - 2025	$ 386,967
85	Main Condenser Expansion Joints Unit 3 2025	Replacement of main condenser expansion joints according to the long-range plan to keep the plant running safely and efficiently.	Q4 - 2025	$ 67,485
86	Low Pressure Fead Water Heater Replacement LP1B Unit 3	This project is to replace the low pressure feed water heaters due to indications of them nearing the end of their useful life.	Q4 - 2025	$ 4,270,788
87	Turbine Valves Unit 3 2025	The scope of this project is to replace turbine valves according to the long-range plan to maintain the reliability of the valves.	Q4 - 2025	$ 1,201,968
88	Station Battery Replacement Unit 3 2025	The scope of this project is to replace the battery bank and perform discharge testing.	Q4 - 2025	$ 66,656

Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
89	Heated Junction Thermal Couple Replacement U3	Replace identified degraded heated junction thermal couple (HJTC) in Unit 3.	Q4 - 2025	$ 105,501
90	Reactor Coolant Pump Seal Replacements Unit 3 2025	The scope of this project is replacement of the reactor coolant pump seals according to the long-range plan during outages.	Q4 - 2025	$ 319,291
91	Instrumentation, Controls, and Electrical Unit 3 2025 Outage	During refueling outage, various instrumentation, controls, and electrical equipment are used/replace throughout the site. Examples of this include annunciators, capacitators, control systems, fuses, receivers, transmitters, etc. These devices and more saw dramatic reductions in the materiality qualification for capitalization with the retirement unit catalog change. The scope of this project includes retirement unit catalog qualifying, instruments, controls, and electrical materials and installation.	Q4 - 2025	$ 769,032
92	Switchgear Condenser Monitor Unit 3	The scope of this project will be to incorporate vibration sensors and motor current signature analysis sensors on select equipment	Q4 - 2025	$ 70,748
93	Civil Replacements 2025	The scope of this project is to replace structural assets that qualify as capital to keep work areas safe and reliable.	Q4 - 2025	$ 49,375
94	Fire Protection Underground Loop 2025	The purpose of this project is to replace the degraded fire protection (FP) underground piping in phases. The FP underground piping routinely fails resulting in FP outages.	Q4 - 2025	$ 290,408
95	Computer Network Infrastructure 2025	Lifecycle management for network infrastructure in 2023	Q1 - 2025	$ 291,566
96	Energy Education Center Equipment	This project replaces the current antiquated audio video control system in the Energy Education Center to continue to meet the high audio video standards and excellence for our Emergency Response Organization, quality of executive meetings, alignment meetings, quality training and for the Emergency Preparedness events.	Q4 - 2025	$ 157,094
97	Security Owner Controlled Area Culvert Refurbishment 2025	This project rebuilds/replace worn out drainage culverts on the Palo Verde site extending the useful life of the culverts.	Q4 - 2025	$ 223,631
98	Life Cycle Computer Replacement 2025	Palo Verde has computer workstations (desktop networked computers) that become outdated and need to be replaced periodically. Palo Verde has a computer workstation life cycle program that ensures workstations onsite are replaced on a five-year schedule.	Q4 - 2025	$ 302,571
99	Roof Replacements 2025	The scope of this project is to replace worn out roofs in order of severity.	Q3 - 2025	$ 97,933
100	Minor Facilities Projects 2025 Common	The scope of this project is facilities modernization/refurbishment projects that individually cost less than $100k within the common area.	Q4 - 2025	$ 108,760
101	Minor Material Projects 2025 Common	Replace qualifying minor projects, such as expansion joint replacements within pipe, or cable replacements.	Q4 - 2025	$ 221,923
102	Concrete and Paving 2025	The scope of this project is to replace worn out paving, concrete, and asphalt roadways and sidewalks around the site.	Q4 - 2025	$ 168,973
103	Cathodic Protection 2025	Ongoing replacement of failed anodes and support devices employed in the cathodic protection system.	Q4 - 2025	$ 302,850

Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
104	Palo Verde Information Technology Equipment Replacement 2025	Project will replace technology equipment and tools used for various operational and maintenance needs at Palo Verde.	Q4 - 2025	$ 155,989
105	Electrical Replacements 2025	The scope of this project is to replace electrical assets for lighting, breakers, and cabinets keep work areas safe and reliable.	Q4 - 2025	$ 39,590
106	Data Analytics 2025	At present, production of many of the site metrics is manual, cumbersome, and time-consuming. The scope of this project is to automate gathering and reporting (including analysis) of data used in site metrics to improve management information available to senior management and reduce labor hours.	Q4 - 2025	$ 748,996
107	Chemistry Lab and Test Equipment 2025	Replacement of aging or obsolete Chemistry laboratory and instrumentation to maintain sampling availability and effectiveness.	Q2 - 2025	$ 141,647
108	HVAC Replacement 2025	The scope of this project is to replace failed/failing HVAC units across the site to keep work areas habitable.	Q4 - 2025	$ 51,996
109	Security Tools & Equipment 2025	This project is for purchase and replacement of unreliable and obsolete security tools and equipment for search trains, facilities, firing range, officer gear, etc.	Q4 - 2025	$ 125,896
110	Domestic Service Support Comfort Trailer	Purchase 4 self contained comfort trailers to be deployed in the event of station water leaks in various buildings.	Q1 - 2025	$ 39,404
111	Vehicle Replacement 2025	The scope of this project is to replace a number of aging vehicles to ensure that the site's vehicle fleet is safe and reliable, with minimal maintenance.	Q4 - 2025	$ 923,891
112	Site Tools and Equipment 2025	This project allows the site to purchase and replace old tools and equipment that are unreliable and obsolete with improved and safer models of tools.	Q4 - 2025	$ 336,554
113	Water Resources Breaker Rebuilds Spring	The various circuit breakers at Water Resources are used to power load centers which run the equipment (such as pumps and motors) used in support of water production. All of these breakers are on a preventative maintenance (PM) program for rebuild to assure that they remain in good working condition. The scope of this project includes the complete rebuild of the breakers.	Q1 - 2025	$ 10,544
114	Waste Centrifuge Gear Box B	Replace waste centrifuge gear boxes that are past their useful life.	Q4 - 2025	$ 63,741
115	Water Reclamation Supply System Pipeline 2025	The scope of this project is continuous rebuilding of the water reclamation supply system pipeline that runs from the Phoenix sewage treatment facility to Water Reclamation Facility extending the useful life of the pipe.	Q4 - 2025	$ 1,508,451
116	45 Acre Header Replacement	Replace the existing corroded carbon steel header on the 45 acre makeup reservoir with a coated carbon steel header.	Q4 - 2025	$ 51,157
117	Water Resources Instrumentation, Controls, & Equipment Replacement 2025	Throughout the year, various instrumentation, controls, and electrical equipment are used/replaced throughout the Water Resources Facility. The scope of this project includes retirement unit catalog qualifying, instruments, controls, and electrical materials and installation.	Q4 - 2025	$ 63,128
118	Water Resources Valve Replacements 2025	Periodically replacements of valves/valve internals are required due to degradation/failure. At Water Resources, valves are treated as run to failure components, and replaced when this occurs. The scope of this work authorization includes the replacement of all valves and valve internals at Water Resources whose characteristics and cost align them with the retirement unit catalog.	Q4 - 2025	$ 164,248

Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
119	Water Resources Breaker Rebuilds Fall	The various circuit breakers at Water Resources are used to power load centers which run the equipment (such as pumps and motors) used in support of water production. All of these breakers are on a preventative maintenance (PM) program for rebuild to assure that they remain in good working condition. The scope of this project includes the complete rebuild of the breakers.	Q3 - 2025	$ 19,249
120	Water Resources Tools and Equipment 2025	Various tools and equipment are used throughout the site for repair work, testing, and other general uses to deliver high quality of work. The scope of this project is for the purchase and replacement of site tools and equipment.	Q4 - 2025	$ 41,072
121	Water Resources Cathodic Protection 2025	Water reclamation supply system pipeline cathodic protection anode/rectifier replacement.	Q2 - 2025	$ 82,984
122	Water Resources Equipment Replacement 2025	Capital Maintenance 2025 work authorization for emergent equipment replacement projects with qualifying retirement unit catalog.	Q4 - 2025	$ 35,748
123	Nuclear Trailing Costs	Trailing charges for projects in-service in previous periods		$ (4,910,010)
124	**Total Nuclear**			**$ 90,172,442**

Distribution
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
1	Unplanned Emergency	Maintain and/or restore distribution system operations.	Q3 - 2025	$ 22,316,864
2	Network Protectors	Replace end-of-life network equipment that provides redundant feeds to critical customers such as hospitals.	Q3 - 2025	$ 4,360,785
3	Highway Relocation-Distribution	To comply with requirements driven by governmental agencies.	Q2 - 2025	$ 22,500,255
4	Underground Cable Replacement-Planned	Install underground cable in conduit so that moisture and rocks will not damage the cables.	Q2 - 2025	$ 25,215
5	Underground Cable Replacement-Unplanned	Replace direct buried cable with cable in a conduit system to reduce power outages.	Q4 - 2025	$ 40,685,447
6	Aged Conductor Replacement	Install modern protection devices to protect legacy small wire from damage/burning down during fault conditions and reconductor small wire and backbone sections where necessary.	Q1 - 2025	$ 566,071
7	Aged Relay Replacement	Replacement of electromechanical relays past their useful life.	Q2 - 2025	$ 1,147,993
8	Advanced Grid Technology (AGT) Power Quality	Improve feeder reliability by installing automated devices (supervisory capacitor banks, voltage regulators, and Micatu sensors) to support operations and control processes.	Q4 - 2025	$ 1,043,368
9	Advanced Metering Infrastructure (AMI) Communication Infrastructure	Replace metering devices that use deprecated 2G/3G cellular networks or proprietary mesh networks which are expected to become unavailable/insufficient for business function over time. Enhance metering capabilities for initiatives such as voltage polling and outage notification.	Q3 - 2025	$ 1,309,156
10	Programmatic Pole Attachment Work	Remove secondary conductor from trees and transfer to a secondary pole.	Q3 - 2025	$ 1,865,439
11	Capitalized Tools	Provide tools for field employees in order to work efficiently and safely.	Q4 - 2025	$ 3,893,927
12	Distribution Land Right-of-Way Renewals	Renew contractual agreements to Distribution rights-of-way leases that are due to expire.	Q3 - 2025	$ 684,859
13	Vista: Build New Feeder VS 05 and OH Feeder Tie (SUB)	The purpose of this project is to increase the rating of existing feeders at Vista and also offloading highly loaded transformer and feeders by creating new ties. One of the current feeders (VS 13) is forecasted to 100% of 11.2 MVA capacity rating by 2024. Another feeder (VS 04) is forecasted to 96% of its 13 MVA capacity rating by 2024. And finally the transformer (VS 11) is forecasted to 93% of its 41.7 capacity MVA rating by 2024.	Q3 - 2025	$ 1,404,991
14	West Park: Upgrade Sub Transformers (SUB)	The objective of this project is to mitigate an 103% transformer overload (T1866) condition on by 2025. As West Park substation electrical design is a double breaker double bus configuration both station units must be upgraded, sequentially the sister transformer (T1867) will also increase in capacity by 2025.	Q2 - 2025	$ 5,813,303
15	McMicken New Feeder MCM05 (SUB)	Offload transformer (MCM11), and two feeders (MCM09,13).	Q2 - 2025	$ 1,002,771
16	Hearn New Feeder Tie HE09-HE04 (UG)	To offload feeder (HE04).	Q2 - 2025	$ 955,466
17	Bunker Peak New Feeder BUP06 (SUB)	To offload feeder (MCM10).	Q2 - 2025	$ 2,569,051

Distribution
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
18	Hub West: Upgrade Sub (Sub Xfmr)	Provide a 69/12kV substation source, with the transformer overloaded at 250%.	Q3 - 2025	$ 2,112,071
19	WSC202 Replacement (UG)	Relocate a switch cabinet WSC202 and extended feeder underground to the new location due to proximity to recently widened Yuma Rd. Relocation to help mitigate vehicle interference and ensure safety and reliability risk.	Q2 - 2025	$ 6,693
20	Fire Mitigation	Install SCADA reclosers and SCADA upgrades to existing reclosers on high-fire risk distribution feeders based on the outcome of feeder protection studies.	Q2 - 2025	$ 12,372,293
21	Grid Hardening	Grid improvement projects on high fire risk distribution feeders. Examples of these improvements include, overhead reconductoring, large quantities of wood pole replacements, and overhead to underground conversion work to eliminate overhead primary conductor.	Q3 - 2025	$ 1,158,680
22	Fire Mitigation Patrol Replacements	Corrective maintance work in areas where there is potential to cause a system to ground event in high fire risk areas	Q1 - 2025	$ 6,440,516
23	Fire Mitigation Pole Replacements	Replace wooden poles to mitigate public hazards on high risk feeders and harden distribution system in high-fire risk areas.	Q3 - 2025	$ 7,482,300
24	Fire Mitigation Weather Station	Installation of Fire Mitigation AI cameras and weather stations as well as customer experience improvements related to Public Safety Power Shutoff customer notifications.	Q4 - 2025	$ 9,819,915
25	Evans Churchill Substation	Install 69kV Gas Insulated Switchgear (GIS), substation transformers, capacitor banks and control equipment to improve capacity, reduce safety hazards and improve reliability.	Q4 - 2025	$ 21,101,593
26	Overhead Planned Replacements	Replace damaged, defective or failed equipment needing replacement as noted during annual Distribution Line Patrols.	Q2 - 2025	$ 20,894,764
27	Capital Non-AMI Meters	Maintain Non-AMI meter inventory.	Q4 - 2025	$ 344,112
28	Wood Pole Replacements	Replace poles with less than 10 years of remaining life to reduce distribution outages due to downed distribution poles and mitigate public hazards.	Q3 - 2025	$ 1,972,926
29	Saguaro: Rebuild Feeder Line-(OH Line)	Rebuild the Saguaro SG 13 feeder by upgrading approximately 800 feet of overhead 336 spans, install new recloser, dip and trench and install underground feeder loop tie	Q4 - 2025	$ 4,729,291
30	Service Replacements	Install service/secondary cable in conduit so that moisture and rocks will not damage the cables.	Q1 - 2025	$ 10,287,223
31	Storm Restoration - Lines	Restore distribution system equipment damaged during storms.	Q3 - 2025	$ 4,718,369
32	Streetlights and Dusk to Dawn	Provide streetlight and dusk to dawn services to customers.	Q1 - 2025	$ 7,508,635
33	Substation Aged Equipment Replacements	Replace aged, end-of-life assets to ensure a reliable system.	Q2 - 2025	$ 6,602,936
34	Watson to Tuthill Rebuild: Tuthill (SUBS)	Purpose is to upgrade the disconnect switches, jumpers, and line relay to prevent overload.	Q4 - 2025	$ 138,065
35	Underground Cabinet Replacement	Replace switching cabinets with broken latches or holes to reduce safety hazards.	Q1 - 2025	$ 3,530,253

Distribution
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
36	Underground Transformer Replacement	Replace damaged transformers to eliminate environmental and safety hazards.	Q2 - 2025	$ 22,119,743
37	Pole Relocation	This project is to utilized for customer or private parties that request relocations or conversions where there are no conflicts. There is no municipality involvement on these jobs, and they should be 100% reimbursable.	Q4 - 2025	$ 78,381
38	Fire Mitigation SCADA Deployment	Deployment of Supervisory Control and Data Acquisition (SCADA) for Fire Mitigation	Q3 - 2025	$ 9,881
39	Pole Replacement Eloy	The purpose of this project is to replace the rusted elements on poles in Eloy.	Q3 - 2025	$ 40,555
40	Fire Mitigation Energy Fuse Upgrades	Upgrade the existing overhead fuses on high-fire risk feeders to expulsion-limiting fuses.	Q4 - 2025	$ 5,937,586
41	Coolidge: Build Feeder Tie between Coolidge 01 and Coolidge 02	Create an underground feeder tie between Coolidge 01 and Coolidge 02 to alleviate a forecasted loading on Coolidge 02 and allow Coolidge 01 to balance out the feeder loading.	Q1 - 2025	$ 16,009
42	Pole Replacement Joint Use	Joint use pole replacements	Q4 - 2025	$ 1,584,781
43	Oil Switch Replacement	Remove and replace aged switch infrastructure that presents a significant safety risk to operators.	Q2 - 2025	$ 86,039
44	Advanced Grid Technology (AGT) Reliability	Improve feeder reliability by installing automated devices (supervisory reclosers and communicating trip savers) to support operations, fire mitigation, and control processes.	Q4 - 2025	$ 87,594
45	Hedgepeth Hills Property Sale	Sale of an unused portion of the Hedgepeth Hills substation parcel	Q1 - 2025	$ (704,291)
46	Distribution Trailing Costs	Trailing charges for projects in-service in previous periods		$ 178,120
47	**Total Distribution**			**$ 262,799,992**

Non-Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
1	Motors / Pumps / Valves	Execute both scheduled and emergent motor, pump, and valve replacement projects across the fossil fleet.	Q4 - 2025	$ 33,248,738
2	Catalyst	Execute both scheduled and emergent catalyst replacement projects across the fossil fleet.	Q2 - 2025	$ 1,333,821
3	Electrical Systems	Execute both scheduled and emergent breaker replacement projects across the fossil fleet.	Q4 - 2025	$ 9,163,602
4	Air Compressors	Ensure the timely replacement of air compressors in the fossil generation fleet to ensure unit reliability.	Q2 - 2025	$ 2,479,035
5	Water Systems/Membranes	Execute both scheduled and emergent water process system, water piping systems, and replacement reverse osmosis membrane projects across the fossil fleet.	Q4 - 2025	$ 7,157,981
6	Outage Discovery	Emergent capital replacements that can only be identified by visual inspection during plant outages.	Q2 - 2025	$ 61,068,690
7	Generation Document Management Portal (GDMP) Creation	The purpose of this project is to improve management and execution of new and retrofit projects through improved project team engagement and delivering project team members, including managers, engineers, stakeholders, and suppliers, a centralized platform for seamless project collaboration and control of project transmittals, submittals, requests for information. and change orders, affording improved project execution in accordance with project scope, cost, and schedule.	Q4 - 2025	$ 2,521,296
8	Enterprise Project Management System (EPMS) Software Changes	The purpose of this project is to improve the functionality of the Enterprise Project Management System project planning and management tool in its alignment with current business process and practice, from a project's conceptualization through a project's closeout. Business process documentation and mapping of Enterprise Project Management System completed in 2024 revealed opportunities that will further improve Enterprise Project Management System functionality and project plan and execution efficiencies through required enhancements of the software.	Q4 - 2025	$ 1,045,835
9	Douglas Fire Detection System	The purpose of this project is to maintain compliance with the National Fire Protection Association 72 - National Fire Alarm Code. Currently there is not a fire alarm detection system installed in the following three areas: battery enclosure, fuel oil handling building, and exciter enclosure.	Q2 - 2025	$ 97,740
10	Four Corners Miscellaneous Lagging & Insulation Replacement - 2025	The purpose of this project is to maintain a safe plant work environment by eliminating potential hazards. These replacements are intended to reduce the hazards that exist when lagging and insulation are loose or deteriorating and therefore not maintaining surface temperature requirements, creating potential unsafe conditions for plant personnel and equipment	Q4 - 2025	$ 98,694
11	Four Corners Lime Feed Header Replacement	The purpose of this project is to maintain environmental compliance with the Title V Permit. Existing lime slurry feed piping between the lime slurry feed pumps to the absorber has deteriorated significantly due to thermal and grit issues.	Q2 - 2025	$ 2,331,076
12	Four Corners Fly Ash Transport System Replacement - Phase 2	The purpose of this project is to maintain environmental compliance with the Title V Permit. The existing pipe is approaching the end of its useful life and has degraded requiring repairs. Completion of this project will allow fly ash to be consistently transferred from the baghouse to the surge bins as necessary to avoid a reportable environmental incident.	Q1 - 2025	$ 513,868
13	Four Corners Vehicle Lease Buyouts - 2025	Capital funds will be used to buy-out the vehicle at the end of the 5-year lease contract as need occurs throughout the 2025 calendar year.	Q4 - 2025	$ 19,253
14	Four Corners Fan Outlet Damper Replacement	The purpose of this project is to maintain unit reliability and to maintain compliance with NFPA 85 requirements regarding properly functioning boiler air dampers. The dampers are approaching the end of their serviceable life and require replacement.	Q1 - 2025	$ 879,760

Non-Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
15	Four Corners Waste Slurry Pump Replacement	The purpose of this project is to maintain unit reliability. Due to the corrosive nature of the waste slurry and sump environment, the existing slurry pumps are unreliable due to the chemicals present in the waste slurry and are approaching end of useful life and are unreliable.	Q2 - 2025	$ 837,030
16	Four Corners Lime Feed Pump Replacement	The purpose of this project is to maintain unit reliability and compliance with the Title V requirements for SO2 Removal Rate. Due to the corrosive nature of the lime feed the existing pumps are approaching end of useful life and are unreliable.	Q2 - 2025	$ 823,700
17	Four Corners Pulverizer Hot Air Dampers Replacement	The purpose of this project is to maintain unit reliability. The pulverizer hot and cold air dampers no longer operate normally having reached the end of their serviceable life and must be manually forced open by Operations.	Q1 - 2025	$ 334,113
18	Four Corners Boiler Feed Pump Overhaul	The purpose of this project is to maintain unit reliability. The Unit 4 boiler feed pumps were last rebuilt in 2010 and in need of an overhaul.	Q2 - 2025	$ 1,982,940
19	Four Corners Fly Ash Blower Replacement	The purpose of this project is to maintain Unit reliability by replacing the fly ash blowers and motors to ensure efficient and dependable removal of fly ash. The existing blowers have been rebuilt multiple times and are obsolete.	Q2 - 2025	$ 1,621,637
20	Four Corners Northwest Baghouse Booster Fan Blade Liner	The purpose of this project is to maintain unit reliability and to avoid unplanned outages or load reduction in the event of a booster fan failure by replacing the blade liners.	Q1 - 2025	$ 778,939
21	Four Corners Southwest Baghouse Booster Fan Blade Liner	The purpose of this project is to maintain unit reliability and to avoid unplanned outages or load reduction in the event of a booster fan failure by replacing the blade liners.	Q1 - 2025	$ 718,401
22	Four Corners Northeast Baghouse Booster Fan Blade Liner	The purpose of this project is to maintain unit reliability and to avoid unplanned outages or load reduction in the event of a booster fan failure by replacing the blade liners.	Q1 - 2025	$ 650,124
23	Four Corners Southeast Baghouse Booster Fan Blade Liner	The purpose of this project is to maintain unit reliability and to avoid unplanned outages or load reduction in the event of a booster fan failure, by replacing the rotor.	Q1 - 2025	$ 614,047
24	Four Corners River Station Rockfall Mitigation	The purpose of this project is to maintain environmental compliance by preventing any potential concrete apron material from falling into the river.	Q4 - 2025	$ 861,324
25	Four Corners Boiler Nose Replacement	The purpose of this project is to maintain unit reliability and reduce the risk of forced outages. The boiler nose has experienced sootblower and ash erosion, resulting in tube leaks.	Q2 - 2025	$ 4,153,714
26	Four Corners Circulating Water Pump Replacement	The purpose of this project is to maintain unit reliability. The Unit 5 North circulating water pump is nearing the end of its serviceable life and replacement is required.	Q2 - 2025	$ 1,762,717
27	Four Corners Economizer Front Wall Stringer Tube Assembly Replacement	The purpose of this project is to reduce back pass tube leaks, decrease forced outage frequency, and lower costs from repairing economizer leaks. High ash loading and velocity has resulted in severe erosion of the economizer stringer assemblies and replacement is required.	Q2 - 2025	$ 913,996

Non-Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
28	Four Corners Baghouse Turning Vane Replacement	The purpose of this project is to maintain unit reliability and to maintain compliance with the Title V Permit by preventing fugitive flue gas emissions to the atmosphere. The turning vanes are significantly eroded and have reached the end of their serviceable like. They are no longer repairable with overlay and patches.	Q1 - 2025	$ 5,862,871
29	Four Corners High-Pressure, Intermediate-Pressure, Low-Pressure Turbine Major Overhaul	The purpose of the project is to maintain unit reliability by ensuring that the high-pressure, intermediate-pressure, low-pressure turbine maintains its original design output efficiency and provides continued reliable operation. Degradation of tip seals over time can result in continued lost generation, a reduction in high-pressure, intermediate-pressure, low-pressure turbine efficiency and high moisture content in the lube oil due to steam leaking by the seals.	Q2 - 2025	$ 35,923,218
30	Four Corners Air Preheater (APH) Basket Replacement	The purpose of this project is to maintain unit reliability. Deterioration of the baskets has impacted heat rate and could cause load curtailment or unit outage.	Q1 - 2025	$ 5,608,426
31	Four Corners Coal Sampler Elevator Replacement	The purpose of this project is to maintain a safe and reliable elevator system to comply with the OSHA General Duty Clause and recommendations found in the HKA Vertical Transportation Comprehensive Maintenance and Condition Audit completed in September 2016. The elevator was found to be in poor condition during the HKA audit, is reaching the end of its serviceable life, and must be replaced.	Q1 - 2025	$ 941,454
32	Four Corners Convection Pass Water Tube Replacement Unit 4	The purpose of this project is to maintain unit reliability while reducing the risk of forced outages. Inspection and lab analysis of recent convection pass water tube failures has identified internal cracking due to corrosion fatigue and external wall thinning (wastage) due to erosion. Tube leaks resulting from this damage are causing forced outages.	Q2 - 2025	$ 7,143,698
33	Four Corners Convection Pass Water Tube Replacement Unit 5	The purpose of this project is to maintain unit reliability while reducing the risk of forced outages. Inspection and lab analysis of recent CPWW tube failures has identified internal cracking due to corrosion fatigue and external wall thinning (wastage) due to erosion. Tube leaks resulting from this damage are causing forced outages	Q4 - 2025	$ 609,189
34	Plant Tools	Ensure the timely replacement of plant tools in the Fossil Generation Fleet to maintain unit reliability.	Q4 - 2025	$ 317,711
35	Expansion Joints	Execute both scheduled and emergent expansion joint replacement projects across the fossil fleet.	Q2 - 2025	$ 3,854,184
36	Seasonal Readiness/Heat Trace	Execute both scheduled and emergent heat trace replacement projects across the fossil fleet.	Q4 - 2025	$ 2,184,932
37	Filters	Execute both scheduled and emergent fabric filter bag replacement projects across the fossil fleet.	Q2 - 2025	$ 3,383,315
38	Coal Handling	Maintain unit reliability by executing scheduled and emergent coal handling and pulverizer equipment replacement and upgrades.	Q4 - 2025	$ 746,059
39	Ocotillo Compressor and Turbine Rotor Replacement, Major Overhaul	The purpose of this project is to ensure unit reliability. Current condition of the compressor blades is driving the recommendation for replacement. Cracks and indications in the rotor are driving the need for replacement.	Q2 - 2025	$ 8,184,399
40	Ocotillo Combustion Turbine 3 Long-Term Service Agreement	The purpose of this project is to fulfill the contractual obligation of the long-term service agreement for combustion turbine 3 at Ocotillo by paying the turbine vendor monthly payments based off unit operation. This money will purchase capital parts and/or services for capital replacement. Parts include fuel nozzles, combustion baskets, transition pieces, turbine blades, etc.	Q4 - 2025	$ 1,939,773

Non-Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
41	Ocotillo Combustion Turbine4 Long-Term Service Agreement	The purpose of this project is to fulfill the contractual obligation of the long-term service agreement for combustion turbine 4 at Ocotillo by paying the turbine vendor monthly payments based off unit operation. This money will purchase capital parts and/or services for capital replacement. Parts include fuel nozzles, combustion baskets, transition pieces, turbine blades, etc.	Q4 - 2025	$ 1,550,177
42	Ocotillo Combustion Turbine 7 Long-Term Service Agreement	The purpose of this project is to fulfill the contractual obligation of the long-term service agreement for combustion turbine 7 at Ocotillo by paying the turbine vendor monthly payments based off unit operation. This money will purchase capital parts and/or services for capital replacement. Parts include fuel nozzles, combustion baskets, transition pieces, turbine blades, etc.	Q4 - 2025	$ 1,720,492
43	Ocotillo Combustion Turbine 5 Long-Term Service Agreement	The purpose of this project is to fulfill the contractual obligation of the long-term service agreement for combustion turbine 5 at Ocotillo by paying the turbine vendor monthly payments based off unit operation. This money will purchase capital parts and/or services for capital replacement. Parts include fuel nozzles, combustion baskets, transition pieces, turbine blades, etc.	Q4 - 2025	$ 1,647,998
44	Ocotillo Combustion Turbine 6 Long-Term Service Agreement	The purpose of this project is to fulfill the contractual obligation of the long-term service agreement for combustion turbine 6 at Ocotillo by paying the turbine vendor monthly payments based off unit operation. This money will purchase capital parts and/or services for capital replacement. Parts include fuel nozzles, combustion baskets, transition pieces, turbine blades, etc.	Q4 - 2025	$ 1,765,937
45	Ocotillo Install New Chiller Loop Air & Dirt Separator	The purpose of this project is to ensure availability of chilled water to the turbine air inlet. Recent investigation of the return chilled water piping has revealed build up of material within the pipes.	Q1 - 2025	$ 1,103,609
46	Redhawk Install Cooling Tower Level Transmitters Unit 2	The purpose of this project is to maintain unit reliability by replacing the level transmitters on the Unit 2 cooling tower. The current level transmitters are not reliable and have caused problems and potential outage situations. This project will install reliable transmitters and create a new control logic that will replace the cooling tower level control operation.	Q1 - 2025	$ 216,347
47	Redhawk Second Makeup Water Pond	The purpose of the second makeup water surge pond is to maintain Environmental compliance by allowing for the relining of the current makeup water pond.	Q4 - 2025	$ 49,835,554
48	Redhawk 2A Gas Turbine Rotor Replacement	The purpose of this project is to ensure unit availability and reliability. Replacement of the 2A gas turbine rotor is per original equipment manufacturer recommendation due to accumulated run hours and replacement of Unit 1B and Unit 2B in 2018 and 2019.	Q1 - 2025	$ 30,877,694
49	Redhawk East Brine Concentrator Surge Pond	The purpose of this project is to ensure unit availability. This new pond will allow for increased storage and redundancy when the zero liquid discharge is down, enabling the unit to stay online by controlling cooling tower conductivity when zero liquid discharge is out of service or the current pond is out of service for relining or leaks.	Q4 - 2025	$ 8,776,801
50	Redhawk Heat Recovery Steam Generator Sample Chiller	The purpose of this project is to ensure reliability of unit sampling systems. The chiller cools the sample stream to the proper temperature, which allows for the analyzers to fulfill their design.	Q4 - 2025	$ 1,232,577
51	Redhawk Replace ABB Controller Card BRC and GE HMI	The purpose of this project is to maintain reliability of the unit. The current ABB controller cards model BRC100 are approaching the end of their lifes.Their limitation on the performance and space which are becoming an issue when we continue to add logic needed by the plant.	Q1 - 2025	$ 211,029

Non-Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
52	Redhawk Zero Liquid Discharge Deaerator Replacement	The purpose of this project is to ensure reliable and efficient zero liquid discharge system operation. The current health of the deaerator and subsequent operation has dictated the need for replacement.	Q4 - 2025	$ 378,170
53	Redhawk Install Serveron Gas Monitoring on Generator Stepup Transformer	The purpose of this project is to ensure unit reliability. The Serveron gas monitoring system will report the health of the generator step-up transformer to the TOAN system to display any changes in the transformer oil chemistry, thereby alerting the plant of any operational anomalies that have occurred with the transformer operations.	Q4 - 2025	$ 242,833
54	Redhawk Replace 1A/B Exhaust Thermowells and Thermocouples	The purpose of this project is to ensure unit reliability and lessen the risk of component failure. The existing thermocouples need to be replaced with the newest thermocouple.	Q4 - 2025	$ 396,746
55	Redhawk Firewater Pipe & Valve Replacement	The purpose of this project is to maintain compliance with NFPA 25. There has been leakage identified and corrected within the firewater loop over the years. Replacement is needed based off observed material condition to preclude more failures.	Q3 - 2025	$ 5,413,594
56	Redhawk 2A Major and 2B Hot Gas Path Overhaul	The purpose of this project is to ensure unit availability and reliability. This project will consist of replacement of turbine components in accordance with the contractually scheduled overhauls in order to ensure reliable and safe operation of the Unit 2A and 2B Gas Turbines.	Q1 - 2025	$ 52,385,966
57	Sundance High Pressure Compressor Blade Replacement	The purpose of this project is to maintain turbine reliability by replacing components per original equipment manufacturer recommendations. Based on projected accumulated starts, these blades will require replacement in fall 2024.	Q4 - 2025	$ 4,584,464
58	Sundance Turbine Removal Tools Storage Area	The purpose of this project is to ensure efficient maintenance activities at the site. The original equipment manufacturer designed original turbine removal tools are currently stored on grade, often muddy and overgrown with desert plants.	Q3 - 2025	$ 1,206,386
59	Sundance Distributed Control System (DCS) Module Communication Replacement	The purpose is to maintain reliability of units. The existing ABB fiber loop communication modules and power conditioning units are reaching the end of life and they are no longer supported by ABB.	Q4 - 2025	$ 1,508,016
60	Sundance Asphalt Replacement	The purpose of this project to replace degraded pavement throughout the site. Existing asphalt roads have degraded and are beyond repair. Asphalt must be removed, subbase improved and new asphalt installed to properly restore the roads. Concrete scuppers will be installed in locations to carry water across the road to prevent future degradation of new asphalt.	Q2 - 2025	$ 1,313,971
61	West Phoenix Cooling Tower Apron Installation	The purpose of this project is to ensure continued compliance with the site Aquifer Protection Permit as to where plant process water should be discharged to. All cooling towers experience splash out or carryover when the tower fans are off while water continues to flow through the tower. This could result in discharge of process water to the ground if aprons and associated drainage and sump systems are not installed.	Q2 - 2025	$ 2,442,066
62	West PhoenixRight of Way License Payment 2025 thru 2026	The purpose of this project is to meet the payment requirements as described in right of way license agreement no. 0229874 between Arizona Public Service Company and Union Pacific.	Q1 - 2025	$ 15,499

Non-Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
63	West Phoenix Replacement of Combustion Components (Fuel Nozzles, Liners, Transition Pieces)	The purpose of this project is to maintain unit reliability. Combined Cycle 3 gas turbine original equipment manufacturer recommendations states that liners and transition pieces are due for replacement after 8,000 operating hours. Based off projected hours, Combined Cycle 3 will require replacement of these components in Fall 2025.	Q4 - 2025	$ 1,160,146
64	West Phoenix Combined Cycle 4 Automate Amine Skid Control	The purpose of this project is to maintain reliability of the unit by enabling automatic control of the boiler chemistry injection pumps on the skid. Currently, the four Amine pumps are manually adjusted and untimely most times. This can lead to a negative impact to the boiler and pipings life.	Q1 - 2025	$ 400,368
65	West Phoenix Combined Cycle 2 Sump Pump Level Control	The purpose is to ensure the sump pump controls the level of the sump pump well.	Q4 - 2025	$ 118,708
66	West Phoenix Combined Cycle 3 Sump Pump Level Control	The purpose is to ensure the sump pump controls the level of the sump pump well.	Q4 - 2025	$ 255,824
67	West Phoenix Combustion Turbine 5A Long Term Maintenance Parts - 2025	The purpose of this project is to establish a capital cash flow in the Long Range Forecast to ensure funds are appropriately budgeted for WP CC5A gas turbine long term maintenance agreement with the original equipment manufacturer. A separate project will be established each year to track the monthly payments for capital parts.	Q4 - 2025	$ 2,529,596
68	West Phoenix Combustion Turbine 5B Long Term Maintenance Parts - 2025	The purpose of this project is to establish a capital cash flow in the Long Range Forecast to ensure funds are appropriately budgeted for WP CC5B gas turbine long term maintenance agreement with the original equipment manufacturer. A separate project will be established each year to track the monthly payments for capital parts.	Q4 - 2025	$ 2,714,794
69	Yucca Chiller Outer Air Louver Replacement	The purpose of this project is to ensure chiller efficiency and availability. The existing louvers have worn and are near the end of their life on the new tower, installed in 2021.	Q2 - 2025	$ 111,180
70	Yucca Relay Life Cycle Replacement	The electro-mechanical relays are no longer supported by the manufacturer and in the event of a failure, the parts will not be readily available.	Q4 - 2025	$ 1,470,854
71	Yucca Unit 3 Generator Step-Up Transformer Replacement	The purpose of the project is to maintain reliability of the unit. The current generator step-up transformer pre-test results show a degraded condition with high power factor on the windings. We know that is due to the amount of contamination in the oil (both metal and moisture). This transformer for Unit 3 was built in the 1970s and is nearing the end of its useful life.	Q2 - 2025	$ 2,645,344
72	Yucca Potable Water System Replacement	Currently the service water serves the potable water system function at Yucca and does not provide suitable potable water to the site. A clean and safe potable water source for plant operations is required per OSHA 1910.141. YUC014526 will install service water piping to combustion turbines 1, 2, 3, and 4 that are fed from the existing raw water tank.	Q1 - 2025	$ 6,675,581
73	Yucca Cardox Controls Replacement Unit 3	The purpose of this project is to maintain compliance with NFPA 850-7.7.4 Fire Protection. The cardox control modules are obsolete. Further degradation and/or loss of a control module will make the Cardox System inoperable.	Q2 - 2025	$ 1,243,140
74	Yucca Cardox Controls Replacement Unit 4	The purpose of this project is to maintain compliance with NFPA 850-7.7.4 Fire Protection. The cardox control modules are obsolete. Further degradation and/or loss of a control module will make the Cardox System inoperable.	Q4 - 2025	$ 1,373,904
75	Solar Maintenance	Solar Capital Rebuild for Corrective Maitenance	Q4 - 2025	$ 495,232

Non-Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
76	Sundance Gas Modernization Project	Additional peaking capacity is required for customer load growth to provide system reliability. The addition of these two units (90 MW) will allow for more reliance on renewables as this flexible generation is dispatchable, fast starting, fast ramping, and allows for multiple daily starts. These assets will support the integration of more renewable energy resources into the APS generation portfolio while maintaining reliability. Locating these new assets at the Sundance Power Plant, adjacent to the metro-Phoenix load pocket, also provides a transmission system reliability benefit.	Q4 - 2025	$ 175,234,400
77	Ironwood Solar	The purpose of the project is to serve our customers with a clean, reliable and affordable energy by adding 168 MW of renewable resources to APS.	Q4 - 2025	$ 288,688,440
78	Ocotillo Unit 3 Turbine Engine Strut Tube Replacement	The purpose of this project is to ensure unit reliability. Replacement of the current strut tubes with a new design will reduce the chance of failure and unplanned outages on the gas turbine.	Q1 - 2025	$ 15,154,681
79	Ocotillo Unit 1 Modified Major Hot Gas Path and Compressor Blade Replacement	The purpose of this project is to ensure unit reliability. Current condition of the compressor blades is driving the recommendation for replacement. With rotor removal, this major overhaul scope will be absorbed under the planned Hot Gas Path (HGP).	Q4 - 2025	$ 4,196,004
80	Batteries/Chargers/Uninterruptible Power Supply	Execute scheduled and emergent batteries, chargers, uninterruptible power supply replacement projects across the fossil fleet.	Q4 - 2025	$ 54,177
81	West Phoenix Unit 2 Replacement of Combustion Components	The purpose of this project is to maintain unit reliability. Combined Cycle 2 Gas Turbine Original Equipment Manufacturer (OEM) recommendations states that liners and transition pieces are due for replacement after 8,000 operating hours. Based off projected hours, Combined Cycle 2 will require replacement of these components before summer run 2025.	Q4 - 2025	$ 719,786
82	West Phoenix Local Area Network (LAN) Reliability Infrastructure Upgrades	The purpose of this project is to provide new devices for additional reliability and resiliency to the network. Legacy communications infrastructure is end of life and end of support. The new devices will allow the network to maintain current code levels and protect against security vulnerabilities.	Q4 - 2025	$ 56,655
83	Four Corners Freight Elevator Track Assembly Replacement	The purpose of this project is to replace the Freight Elevator Track Assembly to maintain a safe and reliable system that complies with the Occupational Safety and Health Administration General Duty Clause. Additionally, the Freight Elevator provides access to the upper boiler levels, needed to efficiently transport materials and manpower for required maintenance activities.	Q4 - 2025	$ 60,871
84	Redhawk Combined Cycle 2 Heat Recovery Steam Generator High Pressure Superheat Attemperator Replacement	The purpose of this project is to replace the heat recovery steam generator high pressure superheat attemperator and downstream pipe. During an inspection three internal cracking indications on the pipe downstream of the interstage attemperator were found. The interstage attemperators had a radial and cicumferential liner cracking which has propogated since the last inspection.	Q1 - 2025	$ 308,331
85	Redhawk Reverse Osmosis Feed Tank Piping Replacement	The purpose of this project is to replace the twenty-five year old piping feeding the reverse osmosis feed tank from ground level to the first isolation valve, on the South side from the reverse osmosis feed tank to the suction of the reverse osmosis feed pumps, and on the discharge of the reverse osmosis feed pump through the check valve to the next downstream isolation valve.	Q3 - 2025	$ 203,636
86	Cotton Center Photovoltaic Module Replacement	The purpose of this project is to replace approximately 8,000 230 watt photovoltaic modules at the Cotton Center solar site. This project will ensure unit reliability.	Q2 - 2025	$ 1,861,095
87	Saguaro Combustion Turbine 3 Generator Stator End Winding Support System Installation	The purpose of this project is to maintain unit reliability. The Generator field would not flash due to the Saturated Stator. A voltage event caused the Stator to become saturated which neutralized the Stator. This caused the automatic voltage regulator to increase voltage damaging several card and diodes.	Q2 - 2025	$ 883,026

Non-Nuclear Generation
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
88	West Phoenix Combined Cycle 5 Closed Cooling Water Heat Exchangers Plate Pack Replacements	The purpose of this project is to replace each plate pack on the closed cooling water heat exchangers on Combine Cycle 5.	Q1 - 2025	$ 451,063
89	West Phoenix Hydro-Vac Washout Area	The purpose is to mitigate to risk associated with the Aquifer Protection Permit around the plant. This project will prevent contaminated water from hydro-vac. to reach Aquifer Protection Permit water. It will separate solids from Hydro-vac water and drain water in the pounds while reducing standing water.	Q4 - 2025	$ 606,802
90	West Phoenix Power Plant Training Building Remodeling	The purpose of this project is to remodel the West Phoenix Power Plant Training building office spaces to create additional work spaces in the existing offices for employees on site.	Q4 - 2025	$ 100,853
91	Non-Nuclear Generation Trailing Costs	Trailing charges for projects in-service in previous periods		$ (12,931,364)
92	**Total Non-Nuclear Generation**			**$ 880,380,352**

Energy Storage
POST-TEST YEAR PLANT ADDITIONS

Line No.	Project Name	Purpose	In-Service Date	Actual Project Cost at 12/31/25
1	Agave Battery Energy Storage System (BESS)	Add 150MW of battery energy storage capacity to the existing Agave Solar site.	Q4 - 2025	$ 240,318,205
2	**Total Energy Storage**			**$ 240,318,205**

REBUTTAL TESTIMONY OF MICHAEL EUGENIS

On Behalf of Arizona Public Service Company

Docket No. E-01345A-25-0105

April 3, 2026

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REBUTTAL TESTIMONY OF MICHAEL EUGENIS
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-25-0105)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Michael Eugenis. I am the Director of Resource Planning at Arizona Public Service Company (APS or Company). My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. No.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Science degree in Electrical Engineering from Arizona State University in 2014 and a Master of Business Administration from Grand Canyon University in 2021. I began my professional career in 2014 with APS as an Engineer in the Transmission and Distribution (T&D) organization, where I progressed through various positions of increasing responsibility in Customer Construction, Transmission Planning, and System Protection. I transitioned to Resource Management in 2021 as Supervisor of Resource Planning and became a Manager within the organization in 2022. In 2024, I was promoted to Director of Resource Planning at APS.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (COMMISSION)?

A. I have not previously provided testimony in a rate case before the Commission. However, I have testified as part of a Certificate of Environmental Compatibility (CEC) proceeding before the Arizona Power Plant and Transmission Line Siting Committee. In addition, I have appeared before the Commission to represent the

Company's 2023 Integrated Resource Plan (IRP) and participated in a Commission workshop addressing natural gas infrastructure.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to issues raised by the Commission Utilities Division Staff (Staff) and intervenors concerning the Company's resource planning and procurement processes, as well as the evaluation of resources selected to meet long-term customer demand in a reliable and cost-effective manner. In addition to addressing specific intervenor arguments, my testimony provides an overview of how APS forecasts long-term energy demand from current and future customers, plans for the types and quantity of resources needed to meet that demand, and how APS procures the resources needed to provide least cost, reliable service for customers.

I do not address every detail related to Staff and intervenor recommendations, and it should not be interpreted that I agree with any of their positions unless specifically stated in my testimony.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My testimony addresses intervenor challenges to APS's resource planning and procurement by outlining the Company's technology-neutral planning process (which incorporates load forecasting, resource adequacy, and reliability metrics), the IRP, and the competitive All-Source Request for Proposal (ASRFP) process. I explain how APS evaluates resources by integrating reliability, customer cost, and execution risk across varying system conditions, and why single-metric screening approaches are insufficient. Additionally, I respond to specific challenges to the prudence of APS's decisions on the Agave Battery Energy Storage System (BESS)

project and the Palo Verde Generating Station (PVGS) Unit 2 lease buyback. In addition, my testimony clarifies that environmental, social, and governance (ESG) principles have no impact on how APS selects the best-fit, least-cost resources to serve customer needs for reliable generation. Similarly with respect to mechanisms for cost recovery; ratemaking tools intended to reduce regulatory lag have no bearing on how APS forecasts, plans, and delivers cost-effective, reliable resources for APS's customers. Finally, I describe Resource Planning's role in APS's proposed process for allocating resource costs through a direct assignment methodology.

III. LONG-TERM RESOURCE PLANNING, RELIABILITY AND AFFORDABILITY

Q. PLEASE DESCRIBE THE COMPANY'S LONG-TERM PLANNING PROCESS FOR IDENTIFYING THE RESOURCES NEEDED TO MEET CUSTOMER DEMAND RELIABLY AND COST EFFECTIVELY.

A. APS uses a structured, long-term planning process to ensure customer demand can be met reliably over time while managing cost and system risk. The process begins with developing a forecast of future customer load, which defines the customer energy and capacity needs APS plans to serve. APS then evaluates whether existing and prospective resources can meet that demand under a range of system conditions and assesses the dependable contribution of different resource types. These analyses are integrated through APS's ongoing planning activities and are formally documented in the Company's IRP, which is filed every three years for stakeholder and Commission review. Ultimately, the Company procures resources by soliciting the marketplace and executing agreements that provide reliability at least cost for customers. Each component of this framework is discussed below.

A. *LOAD FORECAST*

Q. WHAT ROLE DOES THE LOAD FORECAST PLAY IN APS'S RESOURCE PLANNING AND PROCUREMENT?

A. The load forecast establishes the amount and timing of future customer energy and capacity needs APS must plan to serve. It provides the foundation for resource adequacy assessments and portfolio evaluations, which identify when new resources, transmission, or other infrastructure investments are required to maintain system reliability.

Q. HOW DOES APS DEVELOP ITS LOAD FORECAST?

A. APS develops its load forecast using statistical analysis informed by population growth, economic conditions, and project-specific forecasts for large customers. Demand from specific future large customers is incorporated into APS's base load forecast only after execution of a binding agreement, which is described in more detail by APS witness Jacob Tetlow in his Rebuttal Testimony. Expressions of interest from prospective customers—"uncommitted" prospective customers—are tracked separately and are not included in the base load forecast.

Q. DOES STAFF RECOGNIZE THE NEED FOR APS'S LOAD FORECAST TO REFLECT RECENT AND PROJECTED LOAD GROWTH?

A. Yes. In his Direct Testimony, Staff witness Dr. Randell M. Johnson identifies rapid and sustained load growth—particularly from large, high load factor customers such as data centers—as a primary planning challenge with material implications for system reliability.[1]

[1] Staff, Direct Testimony of Dr. Randell M. Johnson (Mar. 2, 2026) at 5.

Q. DID STAFF REVIEW APS'S HISTORICAL LOAD FORECAST PERFORMANCE?

A. Yes. Dr. Johnson reviewed APS's load forecast performance for the period 2020 through 2025 and concluded that forecasted results were consistently close to actual outcomes, providing a reasonable foundation for current planning analyses.[2]

Q. OTHER THAN UNPRECEDENTED GROWTH AMONG LARGE HIGH LOAD FACTOR CUSTOMERS, SUCH AS DATA CENTERS, WHAT OTHER FACTORS ARE DRIVING LOAD GROWTH THAT APS IS EXPERIENCING?

A. APS's load growth is also driven by continued population growth in Arizona and sustained economic expansion and diversification, including high-tech manufacturing and other commercial development. In addition, record-breaking temperatures and prolonged periods of extreme heat are increasing overall energy consumption and contributing to higher summer peak demand. Electrification trends, including electric vehicle charging and customers' increasing reliance on electricity for routine activities and business operations, are also adding incremental load.

Q. HOW DOES APS ADDRESS UNCERTAINTY IN LARGE CUSTOMER FORECASTS?

A. APS evaluates project-specific information and applies adjustments based on industry characteristics, experience with similar projects, and customer-specific factors to reflect expected development timing and load ramp. For example, not all data center customers have the same ramping characteristics. The Company has found that "colocation" data centers, which rent space to multiple entities within a building or site, typically ramp slower than those who have a dedicated customer (often referred to as a "hyper scaler"). Separate from the base load forecast

[2] *Id.* at 30-37.

scenarios, the Company's upcoming 2026 IRP will also evaluate how incremental uncommitted demand could be accommodated over time as system conditions evolve.

Q. WHAT MEASURES HAS APS ADOPTED TO MANAGE FORECAST RISK FROM LARGE, HIGH LOAD FACTOR CUSTOMERS?

A. APS has begun requiring large, high load factor customers, such as data centers, to execute a Load Commitment Agreement (LCA) prior to taking service. These agreements require customers to make financial commitments to minimum energy and capacity levels. Among other functions more specifically described in Mr. Tetlow's Rebuttal Testimony, these LCAs help mitigate forecast risk and protect other customers from incurring the cost of resources procured to serve load that may not materialize.

B. *RESOURCE ADEQUACY AND SYSTEM RELIABILITY*

Q. WHAT IS RESOURCE ADEQUACY?

A. Resource adequacy refers to whether the electric system has sufficient dependable resources to meet customer demand at a targeted level of reliability, particularly during periods of greatest system stress.

Q. WHAT CONDITIONS ARE CONSIDERED IN RESOURCE ADEQUACY ASSESSMENTS?

A. These assessments evaluate system performance across a range of conditions, including varying weather patterns and hourly demand profiles, recognizing that reliability risk is not limited to a single peak hour. For instance, in the 2023 IRP, APS utilized weather information across 23 years to inform future reliability needs.[3]

[3] APS's 2023 IRP (Nov. 2023), Appendix D at 3.

Q. WHAT RESOURCE-SPECIFIC FACTORS ARE CONSIDERED?

A. Factors, such as operating limitations, planned maintenance, and forced-outage risk, are included to reflect that some resources may be unavailable or constrained during critical periods.

Q. WHAT DO "FIRM" AND "DISPATCHABLE" MEAN IN RESOURCE PLANNING?

A. In resource planning, firm and dispatchable describe different characteristics of resource availability. A firm resource is a generating resource that can be relied upon to meet electricity demand when needed, consistent with system planning and adequacy concepts, accounting for expected outages and operating limitations, and deliverable to load using firm transmission service. A dispatchable resource is a generating resource whose output can be scheduled, started, stopped, or adjusted by operators on demand to meet system needs, rather than being dependent on weather or other uncontrollable conditions. Some resources, such as natural gas and nuclear generation, are both firm and dispatchable. Other resources may have only one of these characteristics. For example, storage is generally dispatchable but energy-limited, while solar generation is weather dependent.

A resource's dispatchable or firm characteristics alone do not determine its value in a portfolio context. Different resource types contribute in different ways. For example, non-dispatchable renewable resources can provide low-cost energy, while dispatchable and flexible resources, including battery storage, can enhance reliability by shifting energy and supporting system needs during critical hours. Evaluating how these resources operate together in a complementary manner is central to portfolio-based planning and supports resource adequacy and overall system reliability.

Q. VOTE SOLAR WITNESS KATE BOWMAN ARGUES THAT REDUCED ROOFTOP SOLAR ADOPTION WOULD INCREASE APS PEAK LOAD AND TOTAL SYSTEM COSTS.[4] HOW DO YOU RESPOND?

A. Rooftop solar can contribute energy to the system, but its timing and variability do not necessarily align with system capacity and reliability needs, especially during peak hours. As I further discuss resource adequacy and Effective Load Carrying Capability (ELCC) in the next section of my testimony, changes in rooftop solar adoption do not result in a one-for-one change in APS's need to procure dependable capacity. Distributed generation (DG) exports may occur during periods of excess energy, while maintaining system reliability increasingly depends on resources that can perform during evening, overnight, and stressed conditions. Accordingly, APS must plan for dependable, deliverable capacity independent of DG adoption levels.

Q. FEDERAL EXECUTIVE AGENCIES (FEA) WITNESS JESSICA A. YORK CRITICIZES APS FOR RELYING TOO HEAVILY ON ENERGY-WEIGHTED CONCEPTS IN RESOURCE PLANNING.[5] HOW DO YOU RESPOND?

A. APS does not plan its system by treating capacity and energy as separable or independent drivers of system needs. Historically, electric system reliability was largely defined by the ability to meet a single coincident peak, and capacity planning focused on ensuring sufficient resources were available during that narrow peak period. Today, however, system conditions have evolved. Critical hours are no longer confined to the traditional coincident peak, but can occur at different times of day and across longer durations as load shapes change and resource availability varies. As customer load becomes more sustained—particularly for large, high load factor customers—average demand levels rise

[4] Vote Solar, Direct Testimony of Kate Bowman (Mar. 18, 2026) (Bowman Direct-Rate Design) at 14.

[5] FEA, Direct Testimony of Jessica A. York (Mar. 18, 2026) at 4-8.

closer to peak demand, making the distinction between energy usage and peak conditions less pronounced. In those circumstances, reliability is less about serving a single peak hour and more about ensuring the system can perform across a broader range of operating conditions, which requires a portfolio of complementary resources that support both energy needs and peak-driven reliability.

Q. WHAT CHARACTERISTICS MUST A RESOURCE HAVE TO BE DEFINED AS RESOURCE ADEQUATE?

A. To meet resource adequacy needs, a resource must represent reliable, physically backed generation capacity that APS can count on to serve its customers when needed. This means the resource is tied to a specific generating facility, is not already committed to provide capacity or energy to another counterparty, cannot be recalled during periods of grid stress, and is delivered to APS customers using firm transmission rights. These characteristics are required for resources to be eligible for accreditation under the Western Resource Adequacy Program (WRAP), in which APS participates.

1. RESOURCE RELIABILITY AND ELCC

Q. HOW ARE INDIVIDUAL RESOURCES EVALUATED FOR THEIR CONTRIBUTION TO RELIABILITY?

A. APS evaluates resource contributions to system reliability by considering a range of reliability attributes, including operating duration, availability during peak and stressed conditions, fuel security, operating flexibility and dispatchability, forced-outage performance, and the ability to perform reliably during extended or multi-day events. These attributes are evaluated quantitatively and qualitatively, including through ELCC, which measures the dependable capacity a resource provides during periods of highest system risk based on system conditions and overall portfolio performance.

Q. HOW DOES ELCC DIFFER FROM NAMEPLATE CAPACITY?

A. Nameplate capacity reflects a generation resource's maximum output under ideal conditions (such as the output of a solar facility at noon on a clear day), but not whether that output is available during critical hours. ELCC measures the dependable capacity a resource provides when the system is most stressed, accounting for availability and performance during those periods.

Q. HOW DOES ELCC ACCOUNT FOR DIFFERENCES ACROSS RESOURCE TYPES?

A. ELCC is a technology-neutral metric that evaluates all resources based on their actual contribution to system reliability. Resources with greater operational flexibility and availability during stressed conditions generally provide higher dependable capacity, while resources that are weather dependent, energy limited, or more outage prone may provide less. ELCC captures these differences consistently across the portfolio.

Q. DOES ELCC CHANGE OVER TIME?

A. Yes. ELCC is portfolio dependent and reflects prevailing system conditions. As the resource mix evolves, the hours of greatest reliability risk can shift, which may increase, decrease, or leave unchanged a resource's ELCC. For this reason, ELCC must be evaluated in the context of system conditions at the time planning decisions are made.

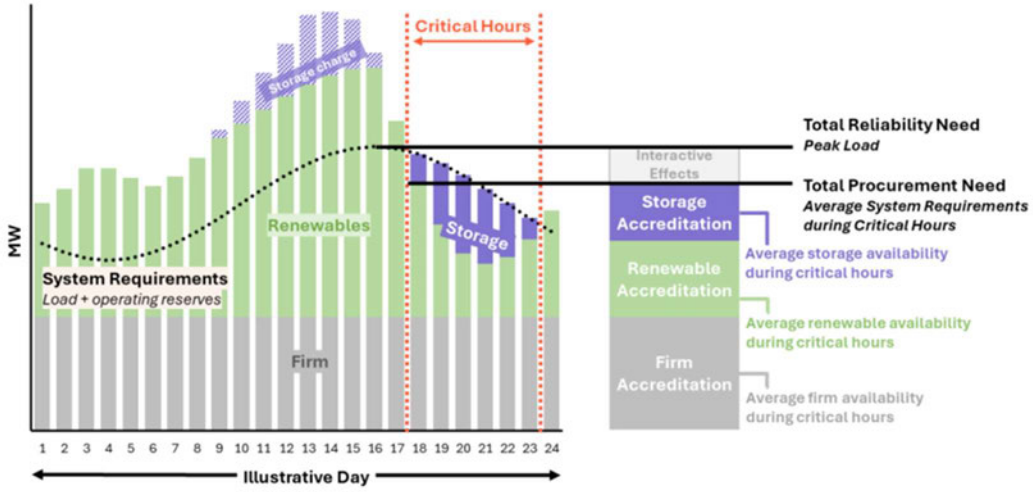
Q. PLEASE PROVIDE AN EXAMPLE OF HOW THE HOURS OF GREATEST RISK CAN SHIFT.

A. As shown in Figure 1,[6] the hours of highest reliability risk depend on when customer demand is highest and which resources are available to meet that demand.

[6] Energy+Environmental Economics, *Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets* (August 2025) at 28, available at https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf.

Historically, APS's greatest reliability risk has occurred during summer afternoons, when high temperatures drive elevated cooling related demand across the system.

Figure 1. Critical Periods Framework



As solar resources have been added to APS's system, they provide increasing amounts of energy during daylight hours. Over time, the system's most critical hours have moved later in the day, as solar output declines and the system becomes increasingly dependent on other resources to meet load. This is shown above in Figure 1 as the current critical hours of greatest system risk and need have shifted later in the day after the traditional late afternoon peak.

During these hours, net load, the portion of customer demand that must be served by resources available at that time, is rising, and reliability depends on the availability of resources capable of serving that demand, such as dispatchable, non-energy limited resources (e.g., natural gas generation) and dispatchable, energy limited resources (e.g., batteries). As a result, the marginal resource contributing to reliability may differ from that during the traditional afternoon peak.

Q. WHY IS ELCC IMPORTANT FOR PLANNING AND REGULATION?

A. ELCC ensures resources are evaluated in a consistent manner based on their actual contribution to reliability during periods of highest system risk, supporting accurate reliability assessments and informed portfolio comparisons while managing total system costs.

C. *INTEGRATED RESOURCE PLAN*

Q. WHAT IS THE IRP, AND WHAT ROLE DOES IT PLAY IN PLANNING?

A. The IRP is a planning document filed every three years[7] that presents the results of the Company's long-term resource planning analyses for stakeholder and Commission review. It reflects a snapshot of APS's integrated planning process at a point in time, bringing together the Company's load forecast, resource adequacy assessments, and reliability metrics to evaluate long-term resource strategies. While the IRP is an important planning milestone, APS's integrated planning process is ongoing and continues to be updated as system conditions, customer demand, and resource characteristics change.

Q. HOW DOES THE IRP BALANCE RELIABILITY AND AFFORDABILITY?

A. All scenarios within the IRP meet the same reliability criteria, although they may differ in execution risk. Within that framework, the modeling software used by the Company identifies the portfolio of resources that meets reliability criteria at lowest total cost. Cost evaluation reflects multiple inputs, including capital investment, fuel expenses, and generic transmission expansion, among others. Based on these inputs, the preferred plan is the portfolio that is both least-cost and

[7] *In the Matter of Resource Planning and Procurement in 2015 and 2016,* Docket No. E-00000V-15-0094, Decision No. 75269 (Sep. 16, 2015). The Commission extended the IRP cycle to three years, instead of the two years required in A.C.C. R14-2-703. This three-year cycle has been continued in subsequent IRP cycles by the Commission approving a waiver of the two-year requirement.

executable under the most likely future scenario, while maintaining reliable service for APS customers.

Q. HOW DOES THE IRP ADDRESS UNCERTAINTY?

A. The IRP evaluates resource portfolios across a range of scenarios reflecting uncertainty in key drivers such as load growth, fuel prices, and technology capital costs. Scenario analysis allows APS to assess how the most cost-effective portfolio changes under different plausible futures and to better understand the role of individual resources across a range of outcomes.

Q. WHAT ROLE DO STAKEHOLDERS AND STAFF PLAY IN THE IRP?

A. APS develops the IRP through a transparent process that includes diverse stakeholder engagement and Commission review and acknowledgment. Stakeholders have opportunities to provide input on assumptions, modeling approaches, and portfolio results, and the Commission reviews the IRP to provide oversight of the Company's long-term planning framework. This process helps ensure that planning assumptions and outcomes are well informed and consistent with the public interest.

IV. RESOURCE PROCUREMENT AND ACQUISITION

Q. HOW DOES APS PROCURE RESOURCES TO MEET THE NEEDS IDENTIFIED THROUGH ITS FORECASTING AND INTEGRATED PLANNING PROCESSES?

A. APS procures resources through its competitive ASRFP process, which is designed to identify the most cost-effective options to meet IRP-identified system needs. While the IRP informs future resource needs, the ASRFP process ultimately determines which resources are selected and procured.

Q. HOW DOES APS EVALUATE AND SCORE BIDS SUBMITTED THROUGH ITS ASRFP PROCESS?

A. APS evaluates ASRFP bids through an objective, multistage process designed to identify the most reliable and cost-effective resources. Proposals that meet eligibility and competitiveness requirements are first evaluated within their respective technology categories using a standardized framework that considers inputs such as price, project viability, and reliability attributes.[8] Competitive bids are then evaluated in a portfolio context using resource planning and production cost modeling to assess how combinations of resources perform in meeting system needs at the lowest overall cost. The process is technology-neutral and focused on maintaining reliability while minimizing customer costs.[9]

Q. HOW DO YOU RESPOND TO MS. BOWMAN'S SUGGESTION THAT RELIANCE ON UTILITY-SCALE RESOURCES SHIFTS COSTS THAT COULD OTHERWISE BE AVOIDED THROUGH GREATER DEPLOYMENT OF DG?[10]

A. APS selects resources based on their ability to meet identified system reliability needs at the lowest total cost, consistent with the portfolio-based planning and procurement framework described earlier in my testimony.[11] That determination depends on how and when a resource performs at the system level, not on whether it is customer-owned or utility-owned. Utility-scale resources are procured because they can be sized, located, and, where applicable, dispatched to meet specific reliability requirements.

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[8] APS Initial DR 1.49 Attachment ExcelAPS25RC00501_2023_Shortlist Table for 2026_HIGHLY CONF.xlsx; APS Initial DR 1.49 Attachment ExcelAPS25RC00500_2023 ASRFP Scoring Document_HIGHLY CONF.xlsx.

[9] APS Initial DR 1.49 Attachment ExcelAPS25RC00499_2023 ASRFP LTCE Study Report_HIGHLY CONF.pdf.

[10] Bowman Direct-Rate Design at 71-74.

[11] *See* Sections III and IV, *supra*.

Q. ARIZONA FREE ENTERPRISE CLUB (AZFEC) WITNESS DR. H. STERLING BURNETT ASSERTS THAT APS'S RESOURCE SELECTIONS ARE DRIVEN BY ESG CONSIDERATIONS.[12] HOW DO YOU RESPOND?

A. APS does not select resources based on any ESG preferences. While carbon emissions are included as one of several metrics in the shortlisting stage of the ASRFP process, where bids are evaluated within their respective technology categories, they do not determine which technologies advance or how resources are ultimately selected.[13] Instead, carbon metrics are simply used to compare resources among similar types (solar vs. solar, gas-fired vs. gas fired, etc.). For this reason, this emissions metric has no bearing on whether a given resource type is selected as compared to others (e.g., conventional thermal resources are not penalized when compared to renewable or storage resources). Based on the opportunities offered by market participants, resources are selected according to their ability to meet identified system needs at the lowest cost to customers. ESG considerations do not override these criteria or predetermine outcomes.

[12] AZFEC, Direct Testimony of Sterling Burnett, Ph.D. (Mar. 2, 2026) (Burnett Direct) at 13-14.

[13] APS Initial DR 1.49 Attachment ExcelAPS25RC00501_2023_Shortlist Table for 2026_HIGHLY CONF.xlsx; APS Initial DR 1.49 Attachment ExcelAPS25RC00500_2023 ASRFP Scoring Document_HIGHLY CONF.xlsx; APS Initial DR 1.49 Attachment ExcelAPS25RC00499_2023 ASRFP LTCE Study Report_HIGHLY CONF.pdf.

Q. FEA WITNESS MICHAEL P. GORMAN RAISES CONCERNS THAT FORMULA RATEMAKING MAY WEAKEN COST DISCIPLINE OR INCENTIVIZE PREMATURE CAPITAL INVESTMENTS.[14] DOES THE METHOD OF COST RECOVERY INFLUENCE APS'S RESOURCE PLANNING OR SELECTION DECISIONS?

A. No. As I previously mentioned, APS's resource planning and selection decisions are driven by demonstrated system need and disciplined through planning analysis and competitive procurement, not by the method used to recover costs in rates. Consistent with the planning framework described above, APS identifies the timing and magnitude of resource needs through its load forecasting, resource adequacy analyses, and IRP, independent of any cost recovery mechanism. Once a need is identified, the ASRFP and portfolio evaluation process governs resource selection based on cost, reliability contribution, operational characteristics, execution risk, and performance across a range of conditions. Ratemaking or cost recovery mechanisms do not in any way influence APS's approach to resource planning, selection, or procurement.

V. <u>AGAVE BESS</u>

Q. DO INTERVENORS CHALLENGE THE PRUDENCY OF APS'S PROCUREMENT OF THE AGAVE BATTERY BESS PROJECT?

A. AZFEC witness Isaac Orr challenges the prudency of the Agave BESS project primarily through simplified levelized-cost screening metrics and critiques of battery storage operating characteristics.[15] Additionally, Dr. Burnett contends that APS could have avoided procuring replacement resources such as the Agave BESS project by continuing to operate the Cholla Power Plant (Cholla) as a coal-fired facility[16]—notwithstanding that continued coal-fired operations at Cholla is now

[14] FEA, Direct Testimony of Michael P. Gorman (Mar. 2, 2026) at 6-9.
[15] AZFEC, Direct Testimony of Isaac Orr (Mar. 2, 2026) (Orr Direct) at 13-14.
[16] Burnett Direct at 15-16.

illegal under the federal Clean Air Act. Dr. Burnett also presents superficial challenges to the relative economics of replacement resources. The following testimony addresses these criticisms in detail.

Q. PLEASE EXPLAIN MR. ORR'S CRITICISMS REGARDING APS'S PROCUREMENT OF AGAVE BESS.

A. Mr. Orr's criticisms largely stem from evaluating battery storage as a stand-alone resource rather than within the portfolio-based framework APS uses to plan and procure resources. His analysis also relies on simplified Levelized Cost of Energy (LCOE) and Levelized Cost of Capacity (LCOC) screening comparisons that combine generic assumptions with selected project-specific capital cost information,[17] rather than using the contemporaneous bid data produced through APS's competitive ASRFP process. He treats those screening results as a prudence test rather than evaluating the Agave BESS project within a portfolio-based capacity-expansion framework.

Q. WHY IS IT INAPPROPRIATE TO EVALUATE AGAVE BESS PRIMARILY THROUGH LCOE AND LCOC COMPARISONS?

A. LCOE and LCOC are static screening metrics. They do not capture how resources perform together as a portfolio, the operational value of flexibility and ancillary services, or how storage is dispatched in practice (e.g., charging in low-, even negatively-priced hours and discharging during peak hours). Treating these metrics as decisive is particularly problematic for battery storage because storage is not an energy producing resource; its value depends on when it can charge and discharge and the operational and reliability services it provides. Most importantly, reliability is achieved through a diverse mix of complementary resources. Consistent with industry practice, resource prudence is not determined by LCOE or LCOC rankings

[17] Orr Direct at 2-3.

alone, but through detailed modeling of reliability outcomes, system costs, and risk across multiple scenarios.

Q. WHAT ANALYTICAL FRAMEWORK DOES APS USE TO EVALUATE PORTFOLIOS AND IDENTIFY A LEAST-COST, RELIABLE MIX OF LONG-TERM RESOURCES?

A. The Company uses long-term capacity expansion modeling that reflects hourly load and system conditions and incorporates resource costs and operating characteristics. Consistent with the portfolio-based framework described above, APS accounts for the interactive and complementary effects of resources and identifies portfolios that meet reliability standards at the lowest overall cost by focusing on the highest demand hours and crediting resources based on their dependable contribution (including ELCC, where applicable), rather than one-for-one cost comparisons.

The portfolio framework also captures system interactions and avoided costs (e.g., capacity deferrals, curtailment reductions, and dispatch impacts), incorporates high-level transmission constraints and associated costs, and evaluates uncertainty through scenario analysis, including fuel price volatility and performance risk under alternative future system conditions.

Q. MR. ORR DISCUSSES ROUND-TRIP EFFICIENCY LOSSES AS PART OF HIS LEVELIZED COST ANALYSIS.[18] HOW SHOULD THIS BE CONSIDERED?

A. Round-trip efficiency is simply storage's form of conversion loss, analogous to thermal heat-rate losses and station service, or to inverter and conversion losses for solar and wind—operational characteristics that are routinely reflected in dispatch and production-cost modeling rather than treated as a stand-alone prudence

[18] Orr Direct at 9.

"penalty." Importantly, storage typically charges during low-cost, off-peak hours or when excess generation would otherwise be curtailed, and integrated planning and production-cost models account for charging costs and efficiency losses while evaluating storage based on net system value in the context of the overall, diverse resource portfolio.

Q. MR. ORR CRITICIZES FOUR-HOUR STORAGE AS ENERGY-LIMITED AND POTENTIALLY CONSTRAINED.[19] HOW DO YOU RESPOND?

A. The Company agrees that battery storage resources are energy-limited and must be evaluated based on their duration and recharge characteristics, which is why APS explicitly models these attributes in its long-term resource adequacy and portfolio analyses. The Agave BESS project was not evaluated as a stand-alone resource capable of serving all hours of a multi-day heat event, but as one component of a diversified resource portfolio in which complementary resources work together to meet reliability standards during the highest peak demand hours.

Q. MR. ORR ALSO RAISES CONCERNS REGARDING THE SUITABILITY OF FOUR-HOUR BATTERY STORAGE FOR SERVING EMERGING HIGH LOAD FACTOR CUSTOMERS, SUCH AS DATA CENTERS.[20] HOW DO YOU RESPOND?

A. As discussed above, four-hour battery storage is not intended to serve sustained high load factor demand on a stand-alone basis. Rather, it functions as a complementary resource within a diverse resource portfolio that meets established reliability requirements during periods of highest system demand.

[19] *Id.* at 8.
[20] *Id.* at 12-13.

Q. HOW DOES THE AGAVE BESS PROJECT'S SELECTION THROUGH APS'S ASRFP PROCESS BEAR ON THE PRUDENCE OF THE PROJECT?

A. The Agave BESS project's competitive ASRFP selection demonstrates that it was evaluated against other viable bid projects and determined to be part of a resource portfolio that met resource adequacy and reliability requirements at the lowest available cost.[21] This outcome is consistent with a prudent, market-based procurement process.

Q. DO YOU AGREE WITH MR. ORR'S ASSERTION THAT DECLINING MARGINAL ELCC FOR FOUR-HOUR STORAGE IMPLIES THAT AGAVE BESS WAS AN IMPRUDENT RESOURCE DECISION?

A. No. Mr. Orr's assertion incorrectly treats ELCC as a static metric that declines as additional storage is added.[22] As discussed earlier in my testimony, ELCC is a portfolio-dependent planning metric that can increase, decrease, or remain stable depending on how the resource mix evolves and system critical hours shift. A decline in marginal ELCC under a specific future portfolio configuration does not imply that a resource selected under earlier system conditions lacked capacity value or was imprudent at the time of selection.

The Agave BESS project was evaluated based on expected system conditions, reliability needs, and portfolio configuration at the time of the 2023 ASRFP, and not against hypothetical future system conditions reflecting materially higher storage penetration or different resource mixes.

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[21] APS Initial DR 1.49 Attachment ExcelAPS25RC00501_2023_Shortlist Table for 2026_HIGHLY CONF.xlsx; APS Initial DR 1.49 Attachment ExcelAPS25RC00500_2023 ASRFP Scoring Document_HIGHLY CONF.xlsx; APS Initial DR 1.49 Attachment ExcelAPS25RC00499_2023 ASRFP LTCE Study Report_HIGHLY CONF.pdf.

[22] Orr Direct at 9.

Moreover, APS did not rely on stand-alone or marginal ELCC values in isolation when selecting the Agave BESS project. Instead, the resource was evaluated as part of a portfolio designed to meet established reliability standards at competitive cost, recognizing that ELCC values evolve as system conditions and the resource mix change.[23]

Q. DOES MR. ORR'S COMPARISON OF AGAVE BESS TO GAS FIRED ALTERNATIVES SHOW IT WAS AN IMPRUDENT SELECTION?

A. No. Mr. Orr's conclusion is based on one-for-one comparisons of resources in isolation and does not reflect how APS evaluates resources to meet system needs.[24] Battery storage is not a direct substitute for gas-fired combustion turbines or combined cycle units; it provides different and complementary reliability services that are evaluated accordingly. As discussed earlier, battery energy storage provides fast-responding, dispatchable capacity during the system's most critical hours, supports net-peak reliability as critical hours shift later into the evening, and enhances overall portfolio flexibility by reducing ramping and cycling demands on thermal resources. These attributes are captured through APS's resource adequacy and ELCC analyses, not through simplified levelized cost screening metrics.

Accordingly, the Agave BESS project was not selected because it appeared lower cost than gas fired alternatives in isolation, but because it contributed distinct operational and reliability value as part of a least-cost, resource adequate portfolio.

[23] APS Initial DR 1.49 Attachment ExcelAPS25RC00499_2023 ASRFP LTCE Study Report_HIGHLY CONF.pdf.

[24] Orr Direct at 15.

Q. WHAT ARE THE DEFICIENCIES IN THE COST INPUTS USED IN MR. ORR'S ANALYSIS?

A. The deficiencies in cost inputs used in Mr. Orr's analysis stem from their development outside APS's procurement framework and decision context. Rather than relying on contemporaneous, procurement-specific information, Mr. Orr combines assumptions from different sources, timeframes, and analytical purposes.[25] He relies on outdated, generic, forward-looking capital and operating cost assumptions,[26] rather than the most recent available data, which limits the relevance of his comparisons. Mr. Orr supplements those generic assumptions—in an unspecified manner—with capital cost data from a limited set of natural gas projects completed in 2023,[27] when natural gas generation projects were significantly less expensive than they are today. Mr. Orr does not identify the projects included, explain how many projects were reviewed, or describe their locations, technologies, sizes, or development circumstances. In addition, his analysis does not account for key feasibility constraints—such as siting and transmission limitations, fuel access, development risk, and regional cost variation—that materially affect both cost and deliverability. By blending generic planning benchmarks with selectively applied, unidentified project-level cost information and using those combined inputs for LCOE and LCOC screening comparisons, Mr. Orr's analysis makes it difficult to assess whether the underlying

[25] *Id.* at 2.

[26] *Id*. (Mr. Orr uses the 2023 U.S. Energy Information Administration Annual Energy Outlook (EIA AEO) issued in March 2023, rather than the most recent 2025 EIA AEO issued in April 2025 in his analysis.).

[27] *Id*. (Mr. Orr claims he uses S&P Global data on average actual construction costs for new natural gas facilities completed in 2023, however, no footnote information is provided, so the source is unknown.).

assumptions are comparable, representative, or relevant to APS's procurement decisions or system conditions.

In contrast, APS evaluates resources using contemporaneous bid data from its competitive ASRFP process, which yields proposals from specific, viable projects capable of meeting identified system needs within required development schedules. Cost inputs that are not tied to the same procurement context, and that are not fully identified or reconciled, do not provide a reliable basis for identifying realistic alternatives or for evaluating the prudence of APS's resource selection decisions. As such, Mr. Orr's cost comparison analysis should be dismissed.

Q. MR. ORR POINTS TO DIFFERENCES IN LIFECYCLE CHARACTERISTICS BETWEEN BATTERY STORAGE AND THERMAL RESOURCES, INCLUDING THE POTENTIAL NEED FOR MID-LIFE REINVESTMENT.[28] HOW DOES APS TAKE THOSE DIFFERENCES INTO ACCOUNT?

A. The Company recognizes that distinct resource types have different lifecycle characteristics, including differences in aging, operational performance, and maintenance requirements over time. Battery storage and thermal resources differ with respect to performance degradation, maintenance needs, fixed operating and maintenance costs, and the timing of reinvestment or augmentation. APS incorporates these considerations into its planning and evaluation processes to ensure resources are assessed on a consistent, forward-looking basis that reflects reliability needs and potential customer impacts. Mr. Tetlow provides more detail on the differences and similarities between BESS facilities as compared to conventional gas-fired resources.

[28] *Id.* at 3-4.

Q. FINALLY, HOW DO YOU RESPOND TO MR. ORR'S ASSERTION THAT AGAVE BESS WAS SELECTED WITHOUT APPROPRIATE CONSIDERATION OF RELIABILITY?[29]

A. That assertion is incorrect. Reliability and operational performance are foundational to APS's resource evaluation process and are a prerequisite to any economic assessment. For the reasons detailed in my responses to Mr. Orr's other criticisms, the Agave BESS project is an integral part of APS's resource portfolio and supports the Company's ability to meet established reliability standards.

Q. DR. BURNETT IMPLIES APS SHOULD HAVE KEPT CHOLLA OPEN INSTEAD OF INVESTING IN AGAVE BESS.[30] WAS CONTINUED COAL OPERATION AT CHOLLA A REALISTIC OPTION FOR APS?

A. No. APS was required to permanently cease coal firing at Cholla by April 30, 2025, pursuant to Regional Haze requirements under the federal Clean Air Act that were incorporated into Arizona's State Implementation Plan and approved by the United States Environmental Protection Agency. As such, it is illegal to operate Cholla for coal-fired generation beyond this date. Because continued coal operations were not an available option after that date, APS planned for replacement resources through its established planning and competitive procurement processes, including resources such as the Agave BESS project.

Q. DR. BURNETT ALSO SUGGESTS THAT ESG COMMITMENTS AND "CLEAN MEGAWATTS" INCENTIVES CAUSED APS TO FAVOR AGAVE BESS OVER RELIABILITY AND CUSTOMER COST.[31] HOW DO YOU RESPOND?

A. Dr. Burnett relies on Pinnacle West Capital Corporation proxy disclosures and contends that certain executive compensation and performance incentives

[29] *Id.*, Exhibit IO-1 at 6-7.
[30] Burnett Direct at 15-16.
[31] *Id*. at 12-13.

referenced clean energy targets, including a "clean megawatt installed" metric. His argument is an inference drawn from corporate disclosures, not an analysis of APS's resource planning or procurement decision-making. As explained elsewhere in my testimony, APS identifies resource needs through its IRP and resource adequacy analyses and then selects resources through a competitive, technology-neutral ASRFP process that evaluates bid pricing, viability, and reliability attributes. Under that framework, reliability considerations are a prerequisite to economic evaluation, and resources are selected based on whether they meet identified system needs using viable, market-priced projects—not based on ESG commitments or compensation metrics. APS witness Theodore N. Geisler provides more specific information about how APS's "clean MWs installed" metric functions in relation to the incentives for the operation of APS's business in his Rebuttal Testimony.

Q. HOW SHOULD THE COMMISSION EVALUATE THE PRUDENCE OF AGAVE BESS IN LIGHT OF MR. ORR'S AND DR. BURNETT'S CRITIQUES?

A. The Commission should evaluate the prudence of the Agave BESS project based on the fact that APS reasonably addressed reliability needs and customer impacts through its established planning and competitive procurement processes at the time of the decision. While battery storage has defined operational limits, it provides meaningful flexibility and peak-period reliability value when deployed alongside firm generation and transmission resources. The Agave BESS project was evaluated and selected through APS's competitive ASRFP process as part of that integrated planning framework, using viable, market-priced resources.

VI. PVGS UNIT 2 LEASE BUYBACK

Q. WHY DID APS PURCHASE 92 MW OF ITS LEASED SHARE OF PVGS UNIT 2, AND WHAT WORK DID APS PERFORM TO SUPPORT THE PRUDENCY OF THAT INVESTMENT?

A. To support the prudency of the investment, APS conducted a comprehensive economic and risk analysis based on PVGS Unit 2's continued operation within the Company's existing portfolio of resources. APS compared the cost of the lease buyback to the anticipated cost of alternative resources that could provide comparable reliability at lease expiration. The purchase price of less than $2,150/kW was benchmarked against the overnight capital costs of new advanced nuclear and small modular reactors, which fell in the range of approximately $7,000/kW to $10,000/kW in 2025 dollars. [32]

APS's decision to purchase 92 MW of PVGS Unit 2 lease equity was driven by a unique opportunity to acquire a portion of the previously leased interest before the scheduled lease expiration in 2033. APS evaluated this opportunity in the context of rapid load growth, tightening capacity markets, and increasing challenges with permitting and siting new resources. The purchase secured continued, long-term access to reliable, weather-independent capacity and energy from an existing, fully permitted nuclear resource with a proven operating history.

Q. WHAT CUSTOMER BENEFITS RESULTED FROM THIS DECISION?

A. APS identified several customer benefits, including cost and rate stability from securing continued access to firm, carbon-free capacity and energy from an existing resource, avoidance of price and availability uncertainty associated with lease end options in 2033, and mitigation of execution risk and customer exposure to the cost of siting, permitting, and interconnecting replacement firm resources.

[32] *See* APS Response to Staff DR 8.1 (Feb. 5, 2026).

Based on how PVGS performs within APS's diverse portfolio of resources, APS's analysis showed that, over the current license term through 2046, the purchase delivers substantial net customer benefits of approximately $49 million[33] by avoiding higher costs and risks associated with replacing this capacity with new resources. Assuming a 20-year license renewal, the customer benefits extend materially, with APS's analysis showing a net customer benefit of approximately $186 million[34] through 2066.

In his Rebuttal Testimony, Mr. Tetlow discusses APS's current efforts to ensure that PVGS is able to operate through 2066 as part of a subsequent license extension. In light of these efforts and the need to preserve nuclear generating capacity in the United States, such as PVGS, the net customer benefits of the PVGS Unit 2 lease buyback will pay off for customers through 2066.

Q. DID THE COMMISSION PREVIOUSLY AUTHORIZE APS TO ACQUIRE OWNERSHIP OF THE UNIT 2 INTERESTS SUBJECT TO THE LEASE BUYBACK ARRANGEMENT?

A. Yes. As explained in Mr. Tetlow's Direct Testimony, the Commission provided APS with express authorization to repurchase all or a portion of the PVGS Unit 2 lease interests over time, subject to applicable regulatory approvals.[35]

[33] *See* APS Response to AARP DR 1.14 (Mar. 27, 2026) Attachment ExcelAPS25RC02085 _Current License Term_NetBenefitAnalysis PV2_HIGHLY CONF.xlsx.

[34] *See* APS Response to AARP DR 1.14 (Dec. 5, 2025) Attachment ExcelAPS25RC01763_NetBenefitAnalysis PV2_Update_HIGHLY CONF.xlsx.

[35] APS, Direct Testimony of Jacob Tetlow (Jun. 13, 2025) at 18.

Q. DOES COMMISSION STAFF OR OTHER STAKEHOLDERS SUPPORT APS'S DECISION TO PURCHASE THE ADDITIONAL 92 MW EQUITY INTEREST IN PVGS UNIT 2?

A. Yes. Staff witness Ralph C. Smith reviewed APS's purchase of the formerly leased interest in PVGS Unit 2 and concluded that the transaction was reasonable.[36] Mr. Smith explained that PVGS is a crucial, emissions-free source of firm, baseload generation for APS and Arizona customers, and that APS's acquisition secures continued access to that capacity rather than risking higher buyout costs or the potential loss of the interest at lease expiration in 2033.[37] Local Unions of the International Brotherhood of Electrical Workers (IBEW) witness Dennis Carpenter also supported the acquisition, emphasizing that the purchase will help APS meet growing energy demands from large manufacturers and data centers, and that supporting PVGS operations benefits both APS customers' energy needs and the local economy.[38]

Q. PLEASE RESPOND TO AARP WITNESS PAUL ALVAREZ'S CLAIM CHALLENGING THE PRUDENCE OF THE PVGS UNIT 2 LEASE BUYBACK BASED ON COST COMPARISONS WITH SOLAR AND STORAGE AND FUTURE SUPPLY COSTS.

A. Mr. Alvarez frames his critique of the PVGS Unit 2 lease buyback around cost comparisons and timing, contending that APS could defer acquiring the additional equity and rely on alternative resources that he asserts would be lower cost than extending ownership of the PVGS Unit 2 capacity.[39] Mr. Alvarez's comparison reflects an incomplete consideration of the reliability and risk implications of replacing the 92 MW PVGS Unit 2 capacity. His expectation of declining solar and

[36] Staff, Direct Testimony of Ralph C. Smith (Mar. 2, 2026) at 43-45.
[37] *Id.* at 47.
[38] IBEW, Direct Testimony of Dennis Carpenter (Mar. 2, 2026) at 14.
[39] AARP, Direct Testimony of Paul J. Alvarez (Mar. 2, 2026) (Alvarez Direct) at 38-40.

storage costs focuses on nameplate capacity rather than reliability, which does not change the fact that those resources lack the same around-the-clock availability, capacity factor, and onsite fuel characteristics. As system demand increasingly concentrates during evening, overnight, and for extended durations, additional solar and short-duration storage do not proportionally increase supply during those periods.

Q. HOW DOES THE PVGS UNIT 2 LEASE BUYBACK SUPPORT SYSTEM RELIABILITY, AND WHY WAS IT REASONABLE TO PURSUE THE TRANSACTION WHEN APS DID?

A. The purchase secures firm, around-the-clock capacity and energy at a known cost and reduces reliance on speculative assumptions about future resource availability, duration, siting, and performance. It also limits customer exposure to uncertainty associated with replacement options, transmission availability, and execution risk. Waiting until 2033 would have increased reliability and execution risk without providing a corresponding system benefit.

Q. MR. ALVAREZ QUESTIONS APS'S USE OF AN EXTENDED LICENSE TERM IN EVALUATING THE PVGS UNIT 2 LEASE BUYBACK. HOW DO YOU RESPOND?

A. APS evaluated the PVGS Unit 2 lease buyback based on the expected operating life of the unit, including the anticipated license extension. As Mr. Tetlow explains in his Rebuttal Testimony, APS expects the PVGS operating license to be renewed based on the facility's operating history, ongoing Nuclear Regulatory Commission (NRC) oversight, and continued compliance activities. Consistent with that expectation, APS evaluated customer impacts over the extended license period and aligned the depreciation treatment accordingly.

Q. MR. ALVAREZ CRITICIZES APS FOR ONLY USING COSTS FOR NEW NUCLEAR GENERATION TO EVALUATE THE VALUE OF THE PVGS UNIT 2 LEASE BUYBACK. IS THAT ACCURATE?

A. No. While APS referenced new nuclear capital costs in response to data requests (specifically AARP DR 1.12), Mr. Alvarez incorrectly states that those costs were used in the Company's net customer benefit analysis.[40] In fact, the net customer benefit analysis evaluates the PVGS Unit 2 lease buyback purchase against the cost of a new natural-gas-fired combined cycle resource.

Q. MR. ALVAREZ LIMITS HIS ANALYSIS TO THE 2033 LEASE EXPIRATION PERIOD. HOW DOES THIS UNDERSTATE CUSTOMER VALUE?

A. The PVGS Unit 2 lease buyback secures firm capacity and energy through the end of the unit's licensed operating life in 2046, not merely through the 2033 lease expiration. Limiting the analysis to the lease term compares ownership costs to only a portion of the benefits and understates the value of retaining a long lived, firm resource that avoids the need to replace capacity over the full licensed period.

Q. DO THE RESOURCE COSTS IN MR. ALVAREZ'S TABLE 1 PROVIDE A RELIABLE BASIS FOR A PRUDENCY DETERMINATION?

A. No. The entries in Table 1 reflect inconsistent technology characterization and the application of cost assumptions that are not aligned with the underlying reference Mr. Alvarez cites.[41] These deficiencies alone materially undermine the reliability of Table 1 for a prudency determination.

Table 1 refers generically to an "advanced nuclear" resource, but that label does not correspond to any single technology in the cited reference, which provides cost

[40] Provided in response to AARP DR 1.14.
[41] Alvarez Direct at 40.

and performance assumptions for multiple, distinct nuclear technologies. Within the cited source, the capital cost input aligns with one nuclear technology, while the variable operations and maintenance (O&M) input aligns with a different nuclear technology. The fixed O&M value shown for "advanced nuclear" in Table 1 is not found in the cited reference and exceeds the fixed O&M assumptions for all of the nuclear technologies presented. In the context of Mr. Alvarez's use of Table 1 to compare the different resource technologies, this selective and internally inconsistent application of assumptions materially undermines the usefulness of the cost information presented for nuclear technology.

Table 1 also labels the gas-fired resource as combined cycle while applying cost characteristics associated with a simple-cycle combustion turbine, a different class of gas-fired resource in the cited reference. This approach understates the capital requirements and overstates the operating characteristics of a true combined cycle alternative.

Finally, Mr. Alvarez states that Table 1 reflects estimated costs of generation today, yet relies on cost values expressed in 2024 dollars to critique a 2025 lease buyback and a potential capacity replacement decision occurring in 2033. This temporal mismatch further reduces the usefulness of direct cost comparisons across materially different planning horizons.

In summary, the information presented in Table 1 does not present a coherent or internally consistent cost comparison of different resource technologies and therefore does not provide a reliable basis for a prudency determination.

Q. DOES APS AGREE WITH MR. ALVAREZ'S TABLE 1 COSTS FOR A NATURAL GAS-FIRED COMBINED CYCLE UNIT?

A. No. Costs for natural-gas-fired resources have increased materially in recent years, with no indication of near-term reversal.[42] Mr. Alvarez's comparison focuses narrowly on capital cost assumptions and does not account for near-term gas price volatility, fuel uncertainty, or the transmission, interconnection, siting, and execution risks associated with developing and integrating a new facility.

Q. MR. ALVAREZ ARGUES THE CONCEPT OF "BASELOAD" IS OUTDATED. DID APS RELY ON A BASELOAD FRAMEWORK IN THIS DECISION?

A. No. APS does not rely on "baseload" as a planning construct. Resources are evaluated based on the reliability attributes they provide—such as firmness, availability during stressed conditions, and fuel security—and how those attributes perform within the system. The PVGS Unit 2 lease buyback was evaluated on that basis. Mr. Alvarez relies on cost-based comparisons that reflect inconsistent assumptions and selectively combined cost inputs that do not consistently account for differences in resource firmness, operating duration, and longevity relative to PVGS Unit 2 capacity.[43] Consequently, his analysis gives limited weight to the risk-management value of retaining an existing, cost-effective source of firm nuclear capacity through the PVGS Unit 2 lease buyback.

[42] Utility Dive (citing PJM Independent Market Monitor), *Data centers "primary reason" for high PJM capacity prices* (Oct. 2, 2025); S&P Global Market Intelligence (Commodity Insights), *Data center power demand revives PPA market for gas plants* (Oct. 31, 2025); LevelTen Energy, *North America Q1 2025 PPA Price Index – Executive Summary* (Q1 2025, data through Mar. 15, 2025).

[43] Alvarez Direct at 37-42.

Q. DOES THE PVGS UNIT 2 LEASE BUYBACK EXCLUSIVELY BENEFIT FUTURE CUSTOMER GROWTH, SUCH AS DATA CENTERS?

A. No. The lease buyback secures the same capacity and energy from PVGS Unit 2 that has reliably served APS customers for many years. Existing customers will continue to receive the same reliability and low-cost energy benefits from this resource that they receive today. While the asset also supports future system needs, the transaction does not add incremental capacity, and its value is system-wide and shared across the Company's customer base over the long term.

VII. ALLOCATION OF NEW RESOURCE ADDITIONS

Q. PLEASE DESCRIBE APS'S USE OF ALLOCATION FACTORS TO DISTINGUISH BETWEEN RESOURCES SERVING EXISTING CUSTOMERS AND LOAD GROWTH.

A. The Company plans and procures resources on a portfolio, system-wide basis, and those resources collectively serve the integrated electric system. APS does not designate specific generation resources to particular customer classes. Instead, resources are planned and evaluated as part of an integrated portfolio, and allocation determinations are made at the system level rather than on a resource-by-resource basis.

Q. HOW DOES APS DETERMINE THE NEW RESOURCES ATTRIBUTABLE TO EXISTING CUSTOMERS AND TO LOAD GROWTH?

A. The Company determines these shares by comparing the total accredited capacity of new resources to the accredited capacity of retiring resources. To the extent that incremental accredited capacity replaces retiring resources, that portion is attributed to existing customers and allocated using the standard average and peak (A&P) methodology. Any remaining incremental accredited capacity is attributed to load growth.

This approach is described in detail in Section VI of APS witness Jamie Moe's Direct Testimony, which explains how APS's growth-based allocation methodology avoids cost shifts to residential and small business customers and aligns with cost causation principles.

Q. PLEASE PROVIDE AN EXAMPLE OF THE CALCULATION USED TO DETERMINE EXISTING CUSTOMER AND GROWTH SHARES OF NEW RESOURCES.

A. Using calendar years 2024 and 2025 as examples, Figure 2 shows the method APS uses to determine existing customer and growth shares based on the ratio of retired accredited capacity to total new resource accredited capacity. As shown below for 2025, Retired Replacement Share is 22.37% and the Growth Share is 77.63%.

Figure 2. New Resource Accredited Capacity Shares – 2024 and 2025

Line No.	2024 Resource Retirements and Additions	ELCC / Capacity Accreditation (MW)
1	**Retired**	
2	None	-
3	**Total Retired Resources**	**0**
4	**New**	
5	Westwing 1 (BESS)	69
6	El Sol (BESS)	43
7	Sun Streams 3 (Solar + BESS)	213
8	Chevelon Butte 2 (Wind)	65
9	Yuma (Solar + BESS)	69
10	**Total New Resources**	**459**
11	Retired Replacement Share - Existing Customers (Line 3 ÷ Line 10)	0.00%
12	Growth Share - Growth Customers (1 – Line 11)	100.00%

Line No.	2025 Resource Retirements and Additions	ELCC / Capacity Accreditation (MW)
1	**Retired**	
2	Cholla 1&3 (Coal)	380
3	**Total Retired Resources**	**380**
4	**New**	
5	Westwing 2 (BESS)	98
6	Scatterwash 1 (BESS)	139
7	Scatterwash 2 (BESS)	69
8	Papago (BESS)	245
9	Pluto (BESS)	61
10	Sun Streams 4 (Solar + BESS)	296
11	Serrano (Solar + BESS)	211
12	Harquahala Sun (Solar + BESS)	296
13	South Point Toll Uprate (Combined Cycle)	62
14	Agave (BESS)	122
15	Ironwood (Solar)	19
16	Sundance Modernization (Simple Cycle CT)	80
17	**Total New Resources**	**1699**
18	Retired Replacement Share - Existing Customers (Line 3 ÷ Line 17)	22.37%
19	Growth Share - Growth Customers (1 – Line 18)	77.63%

Q. THE STATE OF ARIZONA WITNESS CARYN POTTER QUESTIONS WHETHER APS HAS ADEQUATELY SUPPORTED THE DIFFERENCE IN COSTS BETWEEN NEWLY PROCURED RESOURCES AND LEGACY RESOURCES. HOW DO YOU RESPOND?

A. The Company's analysis is grounded in observed procurement outcomes. New generation resources are selected through a competitive ASRFP process that reflects prevailing market prices, required reliability attributes, and system needs at the time of procurement, while the embedded costs of legacy resources reflect materially different market conditions under which those resources were evaluated and procured. Well-documented, industry-wide factors—including inflation in labor and materials, supply chain constraints, extended development timelines, and the growing need for firm capacity to serve large, high load factor customers such as data centers—have contributed to higher costs for newly procured resources. Independent industry analyses examining these trends clearly show that accelerating load growth is tightening capacity conditions and driving substantial new investment, which places upward pressure on the cost of new generation relative to historical benchmarks.[44]

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[44] Utility Dive (citing PJM Independent Market Monitor), *Data centers "primary reason" for high PJM capacity prices* (Oct. 2, 2025); S&P Global Market Intelligence (Commodity Insights), *Data center power demand revives PPA market for gas plants* (Oct. 31, 2025); LevelTen Energy, *North America Q1 2025 PPA Price Index – Executive Summary* (Q1 2025, data through Mar. 15, 2025).

REBUTTAL TESTIMONY OF KENT C. WALTER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-25-0105

April 3, 2026

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REBUTTAL TESTIMONY OF KENT C. WALTER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-25-0105)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Kent C. Walter. I am the Director of Resource Management Western Market Affairs at Arizona Public Service Company (APS or Company). My business address is 400 North 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. No.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Arts degree in Political Science from Arizona State University in 2006 and a Master of Business Administration from University of Phoenix in 2012. I began my relevant professional experience with APS in 2007 as a Rate and Regulatory Analyst. During my time with the Company, I have held several positions of increasing responsibility within APS's Federal Regulatory, Financial Controls, and Customer Technology teams. I transitioned to Resource Management in 2018 as Manager of Real-time Resource Operations and Trading. In 2024, I was promoted to Director of Resource Management Western Market Affairs.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (COMMISSION)?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rebuttal Testimony is to respond to Commission Utilities Division (Staff) and intervenor testimony on the Company's management of fuel

and purchased power. My testimony is also intended to address arguments from intervenors concerning the Alternative Generation (AG-X) program and other proposed alternative generation arrangements. In addition, I respond to certain arguments raised about the recently constructed second Makeup Water Surge Pond (MWSP) at Redhawk Power Plant (Redhawk). Finally, I address intervenor testimony regarding the Company's residential distributed generation (DG) study, which was ordered in Decision No. 79293. [1]

I do not address every detail related to Staff and intervenor recommendations, and it should not be interpreted that I agree with any of their positions unless specifically stated in my testimony.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My Rebuttal Testimony explains that APS's planning, procurement, and operational processes are intended to ensure reliability, price stability, and affordability for customers. I discuss the nature of the costs recovered through the Power Supply Adjustor (PSA) mechanism and why this mechanism is working well under its current structure. As such, I explain that a 90/10 sharing mechanism for the PSA would not be in the best interest of APS customers because it would impact operational decision-making, create automatic disallowances, and introduce perverse incentives.

I highlight some of the flaws in the AG-X program and discuss the need to ensure resource adequacy (RA). I discuss a few of the ways the AG-X program shifts costs to non-participating customers and explain that the Southwestern region is constrained with regard to generation and supporting infrastructure. My testimony

[1] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Prop. for Ratemaking Purposes*, Docket No. E-01345A-22-0144, Decision No. 79293 (Mar. 5, 2024) (Decision No. 79293).

supports why expanding the program is not a viable solution for serving significant load growth from large, high load factor customers, such as data centers.

My testimony also supports why construction of a second MWSP at Redhawk was a prudent investment that supports generation resources critical for maintaining reliability within APS's service territory. Specifically, my testimony describes the serious reliability risks arising from a long-term, dual unit outage at Redhawk.

Finally, I discuss the Residential DG Analysis that was required in Decision No. 79293. I explain why the two scenarios assessed in the study—one in which DG was replaced with market purchases and another in which DG was replaced with utility-scale solar—are appropriate given the Company's methodologies. I conclude that the study results support the solar credit used in the Company's site-load cost of service study.

III. MANAGEMENT OF RELIABLE AND AFFORDABLE POWER

Q. BRIEFLY DESCRIBE THE PROCESS FOR THE MANAGEMENT OF RELIABLE AND AFFORDABLE POWER.

A. APS considers its customers in every step of the process to ensure reliable and affordable procurement of fuel and purchased power. The process begins with customers and how or when they choose to use electricity. As described in more detail by APS witness Michael Eugenis, APS's rigorous long-range planning and forecasting process establishes the foundation for the procurement of long-term resources, fuel, and purchased power. For the fuel needed to operate APS's conventional thermal power plants, stability in prices is then managed through long-term contracting (coal and pipeline capacity) and natural gas hedging practices. Additionally, when consuming fuel to generate the electricity customers need for reliable service, APS power plant resources, including Power Purchase

Agreements (PPAs), are continually optimized to meet customer needs while also engaging the markets as customer usage shifts in real time on a day-to-day, hour-by-hour basis. These market transactions allow APS to evaluate and take advantage of opportunities to either purchase more cost effective resources at a savings or to sell at a margin, both of which lower customer costs. APS also engages in a centralized market dispatch through the Western Energy Imbalance Market (WEIM). Each of these processes are intended to maintain reliability, mitigate risks of volatility, and reduce costs for customers.

Q. WHAT PROCESSES ENSURE THAT APS'S LONG-TERM PPAS ARE IN THE BEST INTEREST OF CUSTOMERS?

A. APS utilizes the principles of reliability planning and competitive processes to ensure long-term PPAs are the least-cost, best-fit resources for serving customers. As discussed in Mr. Eugenis' Rebuttal Testimony, the Integrated Resource Plan (IRP) is used to communicate to the marketplace when customers have needs for power and to identify likely resource types that meet those needs reliably and affordably. The marketplace uses this information to develop possible solutions to participate in APS's All-Source Request for Proposals (ASRFP) process. The ASRFP process results in a robust set of options for evaluation and selection to meet customer needs in a reliable and affordable manner.

The ASRFP is a competitive, transparent process overseen by an independent monitor to ensure the results are in the best interest of APS's customers. The ASRFP process is open to all resource types and is not limited by the resource types predicted in the IRP. These opportunities can then be pursued if pricing, technological maturity, or other assumptions evolve from those contained in the IRP. As shown in Figure 1 below, APS's ASRFP process is incredibly

competitive, having consistently drawn over 100 unique projects to evaluate annually. Each of these projects competes against the others to ensure customers capture the benefit of competition on pricing and terms.

Figure 1. Highly Competitive ASRFPs



Q. HOW ARE RESOURCES MANAGED TO BEST SERVE CUSTOMERS?

A. APS continuously optimizes its portfolio of generation resources to reliably meet customer demand at the lowest reasonable cost while engaging wholesale markets to enhance customer value. This optimization is performed through a comprehensive production cost model that incorporates resource capabilities, customer load, fuel availability, operational flexibility, and reliability requirements—including contingency response—to determine the least-cost base plan to serve customers.

The same analytical framework informs APS's power traders by calculating the incremental cost to produce additional energy and the decremental cost associated with reducing generation. These cost signals guide APS's power traders, who operate in day-ahead, real-time, and the WEIM to evaluate market opportunities while maintaining system reliability. When market prices exceed APS's incremental production costs, APS may sell energy into the market. Conversely,

when market prices are lower than APS's decremental costs, APS may purchase energy to serve customer load more economically.

APS's participation in wholesale markets is therefore disciplined, data-driven, and grounded in underlying system economics. Market transactions are used to supplement APS's resource portfolio to support reliability objectives, and capture value when market conditions are favorable. All margins from energy sales and cost savings from energy purchases, flow directly to customers by reducing overall fuel and power supply costs.

A. Gas Hedging Practices

Q. HOW DOES THE COMPANY'S HEDGING PRACTICE MANAGE RISK?

A. Hedging fuel costs is a risk-management practice designed to provide price stability for customers over time. A natural gas hedge is a financial transaction that offsets movements in the market price of physical natural gas. The hedge transactions settle financially and are positively or negatively applied to the cost of the physical gas supply.

Under APS's hedging program, the Company fixes a forward natural gas price for a specified volume and period. In exchange, APS pays a fixed price and receives a floating market price from the counterparty. If market prices rise above the fixed hedge price, the hedge generates a financial benefit that offsets the higher cost APS incurs when purchasing physical gas. Conversely, if market prices fall below the fixed hedge price, the hedge results in a financial cost that offsets the lower cost of physical gas. In both cases, the combined effect of the physical gas purchase and the hedge stabilizes the effective fuel cost paid by customers.

For example, if APS enters into a hedge at a fixed price of $2 per unit and the market price later increases to $3, then APS pays $3 for the physical gas but receives a $1financial payment through the hedge, resulting in a net cost of $2. If instead, the market price declines to $1, then APS pays $1 for the physical gas and incurs a $1 cost through the hedge, again resulting in a net cost of $2. In either scenario, the hedge reduces exposure to price volatility and stabilizes fuel costs.

Q. HOW DOES THE HEDGE FUNCTION OVER TIME TO ENSURE MORE STABLE PRICES FOR FUEL COSTS THAT BENEFIT CUSTOMERS?

A. APS manages price risk progressively over time, in a manner similar to dollar-cost averaging. The Company begins hedging portions of its expected natural gas needs up to three years in advance and incrementally increases hedge coverage as the delivery year approaches, ultimately hedging approximately 85% of forecasted natural gas requirements one year ahead of need. This layered approach reduces the risk of locking in prices at a single point in time and provides protection across a range of market conditions as they evolve over time.

Q. WOULD IT BE FAIR TO SAY THAT THE HEDGE FUNCTIONS LIKE AN INSURANCE POLICY?

A. Yes, in practice, that would be correct. During periods without major market disruptions, the hedge may result in a cost, similar to an insurance premium. When significant market events occur—such as supply disruptions, extreme weather, or geopolitical conflict—the hedge provides financial protection by mitigating the most severe price impacts that would otherwise be borne by customers.

Q. HOW HAVE APS'S HEDGE PRACTICES EVOLVED IN RECENT YEARS?

A. Traditionally, APS executes its hedge transactions at the Henry Hub, which is the most liquid natural gas trading point in North America. Although APS does not take physical delivery at Henry Hub, prices at that location are highly correlated

with prices at the San Juan Hub and in the Permian Basin, where APS does take delivery. The depth and liquidity of Henry Hub markets enable greater competition among counterparties and more favorable pricing for financial hedges.

Nonetheless, following a review of its hedging practices with external consultants, APS implemented a basis hedge between Henry Hub and San Juan Hub. This additional hedge secures the price differential between the financial hedge location and APS's primary physical supply point and is designed specifically to manage winter seasonal conditions that can cause temporary price separation between hubs. As such, APS continually evaluates its hedging practices to ensure that it is taking advantage of available market efficiencies for the benefit of customers.

Q. DO YOU AGREE WITH RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO) WITNESS DUSTIN MADSEN'S RECOMMENDATION THAT THE COMMISSION SHOULD DIRECT APS TO PERFORM ANOTHER REVIEW OF ITS HEDGING PRACTICES?[2]

A. No. Another review is not warranted. APS's hedge was recently subject to multiple external consultant reviews and APS submitted those reports as part of APS's prior rate case filed in 2022. Both Ernst & Young and Gelber & Associates reviewed APS's hedging program, resulting in reports finalized in September 2021 and February 2022, respectively, which included recommendations for the Company to consider. These reports and recommendations were reviewed by the Commission and its consultants as part of the fuel audit within the 2022 rate case. Since the 2022 rate case, APS has continued to refine its hedging practices,

[2] RUCO, Direct Testimony of Dustin Madsen, CPA, CDP, CRRA, CPA (CAN), CA (CAN) (Mar. 2, 2026) (Madsen Direct) at 73.

including enhancing its hedging practices by including a winter basis component as described above.

Moreover, during this pending rate case, Staff is conducting a new fuel audit. As part of that review, Staff witness Emily S. Medine has found that the hedge is currently working well and does not identify any concerns or necessary recommended changes for APS's hedging practices.[3] Instead, Ms. Medine comments that the hedge "has accomplished its objectives to significantly reduce gas price volatility."[4]

Taken together, the prior independent reviews, ongoing Commission oversight, and continued incorporation of third-party recommendations indicate that APS's hedging program has already undergone thorough evaluation and is operating as intended. An additional review would be duplicative and is unlikely to yield new insights beyond those already considered and implemented.

B. Managing the PSA Mechanism

Q. DO CUSTOMER PROTECTIONS EXIST AMONG APS'S FUEL AND PURCHASED POWER PROCESSES?

A. Yes. As described earlier, APS's planning, procurement, and operational processes are designed and implemented to protect both customer reliability and price stability. These protections are grounded in APS's requirement to acquire resources consistent with its IRP and through the competitive ASRFP process. APS further manages cost risk through disciplined fuel hedging and optimized dispatch, while engaging wholesale markets to capture additional customer value. Commission oversight provides an added layer of protection through ongoing monthly reporting

[3] Direct Testimony of ACC Staff witness Emily S. Medine (Mar. 18, 2026) at 13-14.
[4] *Id.* at 14.

and periodic audits of fuel and purchased power costs, such as the ongoing audit conducted as part of this rate case.

Q. DOES APS AGREE WITH MR. MADSEN'S RECOMMENDATION TO IMPOSE A 90/10 SHARING MECHANISM WITHIN THE PSA?[5]

A. No. Fuel and purchased power costs are driven by market prices and system conditions that are largely outside the Company's control, including fuel commodity markets, regional supply and demand conditions, weather, geopolitical events, and resource availability. For this reason, the Commission has long treated these costs as pass-through items recovered through the PSA mechanism. Importantly, APS does not earn a return on fuel or purchased power costs; customers pay only the actual cost incurred to serve load, with systems in place to ensure those costs are the lowest reasonably available.

Introducing a cost-sharing mechanism—such as a 90% customer and 10% utility allocation—would not improve customer outcomes. Instead, it would create misaligned incentives by imposing an artificial penalty on the Company when prices increase, or providing a windfall when prices decline, based on factors unrelated to management decisions or operational performance. Such outcomes would not reflect prudence or controllability.

This issue has been examined previously. In Decision No. 73183, the Commission determined that a 90/10 split was not appropriate and approved moving to a 100% passthrough of fuel and purchased power costs.[6] The 90/10 split was again

[5] Madsen Direct at 70-73.

[6] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Property for Ratemaking Purposes*, Docket No. E-01345A-11-0224, Decision No. 73183 (May 24, 2012) at 42 and Exhibit A (Settlement Agreement) at 8.

examined during APS's 2022 rate case and the Commission rejected proposals to resurrect this mechanism.[7] For its part in this proceeding, Staff is not recommending any changes to the PSA, with Staff witness Ralph C. Smith commenting that the PSA as currently structured "appropriately balance[s] the interests of APS and its ratepayers."[8] Mr. Smith reasons that, because fuel and purchased power costs are determined by market forces outside of APS's control, subject to unpredictable and volatile fluctuations, material to APS's financial stability, and collected from customers on a pure pass through basis, the current structure of the PSA should be retained.[9] The PSA already ensures transparency, regulatory oversight (including regular reporting by APS and the completion of periodic audits), and timely recovery of actual costs, while avoiding the distortions and unintended consequences that a sharing mechanism would introduce.

Q. DO YOU AGREE THAT PROFIT INCENTIVES WOULD BETTER INCENTIVIZE MANAGEMENT OF FUEL AND PURCHASED POWER COSTS?

A. No. Cost controls are already embedded in APS's fuel and purchased power procurement processes and reinforced through Commission oversight. Introducing a profit-based incentive within a fuel and purchased power adjustment mechanism would fundamentally alter operational decision making by shifting the focus from reliability-first procurement to short-term financial optimization.

Under a sharing mechanism, the Company would face an immediate financial penalty when prices rise, even when higher-priced resources are necessary to maintain reliability during tight system conditions. This structure would create incentives to delay or avoid procuring reliability-critical resources when outcomes

[7] Decision No. 79293 at 209.
[8] Staff, Direct Testimony of Ralph C. Smith (Mar. 18, 2026) at 20.
[9] *Id.*

are uncertain, but the financial consequence of action is immediate. Such incentives encourage risk-seeking behavior, including deferring purchases in the hope that market conditions improve, scarcity does not materialize, or reliability challenges can be addressed through last-minute actions.

In a reliability-constrained power system, however, the consequences of being wrong are asymmetric. Customers bear the cost of under-procurement through elevated emergency prices or service disruptions, while the Company would retain a financial upside if risks do not materialize. A recovery mechanism designed to incent profit, therefore, undermines the foundational purpose of fuel and purchased power adjustors, which is to enable prudent, reliability-focused procurement under uncertainty rather than to reward or penalize outcomes driven by external factors.

Q. WHAT OTHER NEGATIVE INCENTIVES ARE CREATED BY A 90/10 SHARING MECHANISM UNDER THE PSA?

A. A 90/10 sharing mechanism further introduces negative incentives by creating automatic disallowances tied to events outside APS's control. Under such an approach, APS would absorb a portion of fuel cost increases resulting from regional or global events—such as prolonged geopolitical conflicts or severe winter storms—despite these events being unpredictable and unrelated to management action. An automatic disallowance under a sharing mechanism creates incentives towards financial risk reduction instead of a balance of risk and value. For example, while APS's hedging program mitigates a significant portion of price risk, the Company does not hedge 100% of its fuel needs, as doing so would expose customers to unnecessary cost. Similar to buying more insurance than is appropriate, APS may be incented to hedge more as a means to offset the

financial risk of unplannable events. As noted by Mr. Madsen, a 100% hedge can be costly to customers.[10]

A sharing mechanism would also disincentivize the use of PPAs to meet customer growth. Under a 90/10 structure, even competitively and prudently procured PPAs would be subject to an effective 10% disallowance if their costs exceed the Base Fuel rate, regardless of whether the resource represents the least-cost, best-fit option for customers. The current framework allows each resource decision to be evaluated on its merits without the influence of profit motives or the risk of automatic, outcome-based disallowances. Such procurements are already subject to the rigors of a competitive ASRFP solicitation process. This process inherently ensures that APS is getting the best price possible for customers based on what is available in the market at that time. It would be unreasonable for such market-driven, competitive outcomes to be subject to an automatic 10% disallowance.

Finally, a sharing mechanism would create the potential for windfall profits. When fuel prices decline due to external factors unrelated to APS actions—such as changes in global supply conditions—the Company would retain a share of the savings, even though those savings were not the result of operational performance or risk management decisions. Under the existing adjustor structure, such savings appropriately flow in full to customers.

For these reasons, a sharing mechanism would distort incentives, weaken reliability protections, and undermine the cost-causation principles that fuel and purchased power adjustors are designed to uphold.

[10] Madsen Direct at 73.

IV. AG-X AND PROPOSED ALTERNATIVE APPROACHES TO GENERATION SUPPLY

A. Background on the AG-X Program

Q. PLEASE DESCRIBE THE AG-X PROGRAM.

A. The AG-X program allows participating APS customers with an aggregated peak load of 5 MW or more that are served under Rate Schedules E-34, E-35, E32-L, E-32 TOU L, E-32 M, E-32 TOU M, E-32 S, or E-32 TOU S to negotiate a power purchase with a third-party Generation Service Provider (GSP). The power is delivered to APS and the Company serves the customer. APS credits the customer for the purchase, settles any energy imbalance, and remains responsible for providing transmission and distribution grid services and (to the extent applicable) generation capacity according to the customer's rate schedule. Importantly, the AG-X customer remains APS's customer, with APS ultimately responsible for reliability, which means the Company must ensure that AG-X customers have energy at all times.

Q. HAVE CHANGES BEEN MADE TO LIMIT COSTS AND IMPACTS TO NON-PARTICIPATING CUSTOMERS?

A. Yes. In the prior APS rate case, Decision No. 79293 created clarity around the acceptable energy products customers could provide. Essentially, participating AG-X customers now have a choice as to whether they deliver only energy or energy plus reliability characteristics, identified as RA.

Under the current program construct, customers who choose to provide energy only maintain financial responsibility for energy delivery and, in return, pay $0 for Base Fuel and the PSA, but still pay an APS charge for generation capacity that ensures RA. In the alternative, customers could choose to provide energy that has firm delivery and is not recallable during emergency conditions (*i.e.,* an energy resource

that ensures RA) and pay $0 for Base Fuel, the PSA, and generation capacity, thereby avoiding additional APS charges for maintaining RA.

Q. WHAT IS RESOURCE ADEQUACY AND HOW IS IT INCORPORATED INTO THE PROGRAM?

A. RA reflects the reliability characteristics of resources that determine the ability for the power to be dedicated to APS customers during the periods of highest grid stress. These characteristics generally include: (1) being able to identify the specific source of power; (2) firm transmission rights; and (3) the resource being dedicated to APS customer reliability (*i.e.,* not curtailable in emergency conditions). APS depends on resources with RA characteristics to maintain reliable service to customers.

Q. WHAT IS THE WESTERN RESOURCE ADEQUACY PROGRAM (WRAP) AND WHY IS IT REFERENCED IN THE AG-X PROGRAM?

A. WRAP is a regional reliability planning and compliance program administered by the Western Power Pool that establishes common standards for ensuring RA among its participants across the Western Interconnection. Development of WRAP began in 2019 in response to growing reliability risks in the West, including load growth, thermal resource retirements, and increasing reliance on variable generation resources. WRAP is the first region-wide program in the West to provide a coordinated approach to assessing resource needs, accrediting capacity, and ensuring that participants have sufficient resources available to serve load under stressed system conditions.

APS's participation in WRAP provides important reliability benefits to customers, including access to shared physical capacity during periods of regional grid stress and a transparent, standardized framework for demonstrating RA. WRAP also

establishes a reliability foundation for APS's future participation in regional markets, including being a requirement for loads participating in Markets+.

WRAP evaluates each participant's load and accredited resources through both forward-looking and operational compliance requirements to determine whether sufficient generation is available within the program. As a WRAP participant, APS is obligated to meet these requirements and demonstrate compliance using standardized metrics and methodologies. Consistent with these obligations, APS has incorporated WRAP into its AG-X program as an independent, third-party RA standard. Under AG-X, WRAP requirements govern both load obligations and resource accreditation, seeking to better align requirements for customers in the AG-X program and those taking APS's bundled service.

Q. HOW DOES THE WRAP PROGRAM ENABLE ACCESS TO SHARED PHYSICAL CAPACITY DURING PERIODS OF REGIONAL GRID STRESS?

A. WRAP requires participating entities with surplus RA to make that excess available to participants that are deficient. This sharing obligation materially enhances system reliability by facilitating access to RA-backed transactions rather than reliance on short-term market purchases. Experience during various energy emergency events between 2020 and 2023 demonstrated that short-term market products—including products marketed as "firm" energy—exhibited a high rate of non-delivery during grid stress. Absent modifications to the standard agreements, these products are fundamentally non-RA "economic energy," which means they represent power supplies without a designated resource backing them up. Market participants selling these standard short-term energy products may speculate on their ability to satisfy firm delivery obligations without securing a specific, committed physical resource. In contrast, WRAP's sharing construct identifies

participants with verified excess generation possessing RA characteristics to support transactions that are backed by available, accredited capacity. These transactions are, therefore, substantially more likely to perform as intended during periods of grid stress, when reliable delivery is most critical.

Q. WHAT IS MEANT BY ACCREDITED CAPACITY?

A. Accredited capacity is the portion of a resource's nameplate or installed capability that is recognized by a planning authority, utility, or market operator as reliably available to meet load for purposes of RA planning. In his Rebuttal Testimony, Mr. Eugenis describes the process to calculate an Effective Load Carrying Capability in greater detail, which is a process for accrediting capacity.

Q. DOES APS USE WRAP FOR PLANNING RESOURCES?

A. No. While APS is required to comply with the WRAP requirements, including demonstrating sufficient RA volumes using WRAP-compliant resources, APS continues to plan for RA through the IRP using APS's established planning standards. This is because WRAP participants do not yet maintain generation resources that fully meet all required RA characteristics. In addition, sharing deliverability must be demonstrated to be accessible and reliable through the western regional market APS has selected for eventual participation, Markets+. Finally, WRAP only focuses on defined Summer and Winter seasons, while reliable service to customers must be maintained year-round.

Although APS does not yet rely on WRAP for long-term resource planning within its IRP, WRAP-based resources across the Western Interconnection continue to provide important short-term reliability benefits. APS ensures reliable service not only through its owned and contracted generation portfolio, but also by accessing resources across the region on a real-time basis to optimize customer costs. When APS turns to the market for the benefit of its customers, WRAP enhances this

capability by increasing the availability of resources with verified RA characteristics under a shared regional framework.

Q. IF APS IS NOT A BINDING MEMBER OF WRAP, WHY SHOULD RA REQUIREMENTS STILL BE IMPOSED ON AG-X CUSTOMERS?

A. Foundationally, APS's requirements for RA are not founded in the Company's membership within the WRAP program, but in the IRP planning process that APS has performed for many years and that is the industry standard for reliability planning. For the AG-X program, WRAP provides a third-party forum for setting standards, obligations, and accreditation for RA. But the fundamental premise of requiring RA generation capacity for GSP service under AG-X is to ensure reliability and limit cost shifts for APS customers. Furthermore, APS's participation in WRAP has already started; binding participation is simply when penalties for non-compliance can be imposed.

The RA requirements in the AG-X program are not simply premised on avoiding WRAP penalties—they are based on ensuring that APS customers have reliable service when they need it and that non-AG-X customers are not forced to bear the costs of ensuring RA for GSP-supplied energy-only products. As discussed by the Commission in Decision No. 79293, the RA changes imposed as a result of APS's last rate case were explicitly premised on "ensur[ing] reliable service for all of APS's customers."[11]

Q. IS THE ABILITY FOR A CUSTOMER TO PROCURE GSP-PROVIDED RA DEPENDENT ON WHICH MARKET APS PARTICIPATES IN?

A. No.

[11] Decision No. 79293 at 332.

Q. HOW DO YOU RESPOND TO NRG ENERGY, INC. (NRG) WITNESS LANCE D. KAUFMAN'S REQUESTS FOR CLARITY?

A. APS supports clarity in the AG-X program and will work to address certain issues raised by Mr. Kaufman; however, some of the requested clarifications would constitute program changes or new features which the Company does not propose to incorporate. APS will work to incorporate the clarity requested by Mr. Kaufman's recommendations on "Deliverability and Transmission Requirements," "Operational Control and Resource Use," and "Forward Showing and Timing Requirements."[12]

While individual markets may apply different RA rules, the underlying need for RA, and the ability of resources to provide it, are not dependent on participation in any specific market. Accordingly, APS agrees with Mr. Kaufman that a customer's ability to procure GSP-supplied RA under the AG-X program should not be contingent on which organized market APS is participating in.[13] APS also generally agrees with the principle that, if WRAP were suspended, reliance on the most recently approved RA framework would be appropriate until a new Commission-approved RA methodology is adopted.[14] The Company will work to modify the program terms consistent with Mr. Kaufman's recommendations.

APS is not in a position to propose any changes to clarify the performance obligations and assurances that resources are not double counted. The source of those terms and conditions come directly from the WRAP Business Practices, which outline performance obligations, including required attestations (Business

[12] NRG, Direct Testimony of Lance D. Kaufman (Mar. 18, 2026) (Kaufman Direct) at 19-20.
[13] *Id*. at 22.
[14] *Id*. at 20.

Practices Manual 106), for ensuring resources are not committed to multiple entities. APS does not have the ability to directly modify these terms without corresponding modifications to the WRAP Business Practices.

APS also supports NRG's proposed language for "Eligible Capacity Resources," with a couple of notable exceptions already identified in the current AG-X program guidelines.[15] Specifically, demand response must be provided in a comparable approach to APS as a "Qualifying Resource," as defined in the guidelines. This is because demand response as a load modifying resource has historically had limitations in its ability to be used in the WRAP sharing program, which undermines access to reliability. APS also requires all RA resources to maintain at least an eight-hour call window for dispatch to the system. As APS joins Markets+, its preferred Western regional market platform, RA resources are expected to demonstrate reliability through meeting the Markets+ must offer requirements, which enables dispatch and utilization across the market footprint.

Finally, Mr. Kaufman's proposal that APS establish a capacity market is not reasonable. APS has no authority, let alone the ability to establish a capacity market. As such, this proposal should be rejected.

B. Cost Shift and Other Risks that Remain with the Current AG-X Structure

Q. IS THE AG-X PROGRAM CURRENTLY STRUCTURED TO MINIMIZE IMPACTS TO NON-PARTICIPATING CUSTOMERS?

A. Not necessarily. Significant progress was achieved in the Company's last rate case with the inclusion of RA requirements based on the WRAP framework. Nonetheless, additional gaps have come to light resulting from efforts aimed at

[15] Kaufman Direct at 18-19.

mirroring complex processes and keeping up with changing conditions. These gaps differ between whether a customer procures RA from APS or procures RA from a GSP.

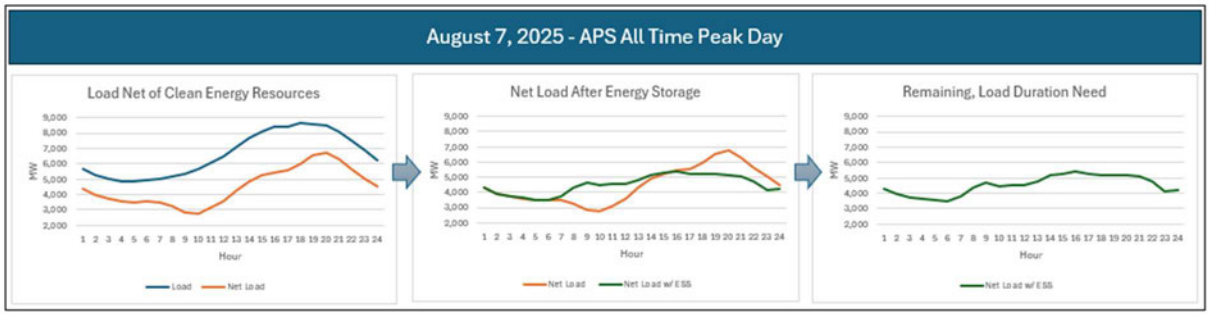
Q. SINCE THE CONCLUSION OF APS'S PRIOR RATE CASE, HAVE CONDITIONS CHANGED WITH REGARD TO THE CAPACITY VALUE OF DEMAND RESPONSE AND OTHER SHORT-DURATION RA RESOURCES?

A. Yes. Since the prior rate case, material changes have occurred that increase the risk of cost impacts to non-participating customers under the current program structure, which still enable short-duration resources to be WRAP accredited for RA purposes. APS's resource needs have shifted from resources designed to meet short-duration peak periods to resources capable of serving customer demand on a continuous basis. This shift is driven largely by substantial growth among large, high load factor customers coupled with the Company's success in deploying resources that have addressed short-duration needs, such as battery energy storage.

Battery energy storage resources effectively address short-duration reliability needs through energy discharge while increasing system demand during lower-load periods through battery charging. APS has developed a significant amount of resources right-sized to address the amount of short-duration customer needs present at the time of those procurements. But as grid conditions have evolved—particularly given growth among large customers that draw high loads virtually around-the-clock—current system demands call for resources that can address longer, relatively flat periods of need. As a result, these evolving system dynamics heighten the potential for cost shifts from new large customers providing only short-duration RA resources.

Figure 2 illustrates this dynamic on the day of APS's alltime system peak. The first panel shows total customer load and the reduction provided by clean energy resources, including solar, wind, and nuclear generation, resulting in net load. The second panel adjusts net load to reflect energy storage operations, increasing net load during charging periods and reducing net load during discharging periods. The third panel shows APS's remaining resource need after all clean energy resources and energy storage are accounted for, demonstrating that even on APS's all-time peak day, the remaining need persists for extended durations.

Figure 2. APS Long- Duration Need



As resource needs have extended in duration, significant growth of customers with high load factors and short-duration backup power resources is occurring. Short-duration resources are not capable of reliably serving sustained, high-duration loads. Nevertheless, under the current AG-X program structure, backup-power, demand response, and other short-duration RA resources receive substantial accreditation, despite their limited ability to meet the system's evolving long-duration reliability needs. As such, since APS's last rate case concluded, longer needs and customers supporting shorter-term RA solutions have brought to light gaps in the program's current structure.

Q. WHAT ARE SOME COST SHIFT GAPS THAT STILL REMAIN IN THE AG-X PROGRAM FOR CUSTOMERS PROVIDING ENERGY ONLY AND PROCURING RA FROM APS?

A. AG-X customers providing energy while purchasing RA from APS do not pay Base Fuel and PSA charges, which allows them to forgo PPA-related costs for generation that add RA to the overall system from which they are still being served. When the AG-X program was initially created, PPA costs were a smaller portion of Base Fuel and PSA costs, because resources under long-term contracts played a smaller role in ensuring RA for all APS customers. Today, however, PPAs make up 60% of Base Fuel and PSA costs. While these customers pay an RA charge intended to compensate APS for necessary generation capacity characteristics, which their energy-only products lack, there are still costs that are shifted to non-AG-X customers. The costs that are shifted represent the underlying RA value provided by the PPAs recovered in Base Fuel rates and PSA charges, which no AG-X customers pay. This gap will be exacerbated should the Commission approve the "growth pays for growth" cost allocation strategy proposed in this case as customers joining the AG-X program can avoid paying the costs of growth (which is more fully described by APS witness Jamie R. Moe in his Direct and Rebuttal Testimonies).

Q. WHAT ARE SOME COST SHIFT GAPS THAT STILL REMAIN IN THE AG-X PROGRAM FOR CUSTOMERS PROVIDING ENERGY AND PROCURING RA FROM A GSP?

A. APS does not have any customers procuring RA from a GSP; however, APS recognizes that if a customer were to procure RA from a GSP, there are gaps that would emerge because of the differences in WRAP and APS IRP planning, as described in the prior section.

In the current program design, an AG-X customer does not need to match the RA with their physical load. For example, a demand response product with only 40 hours of capability can meet WRAP's accreditation standard. However, that same resource product could not actually serve the load for its annual 8,760 hours of need. Because it cannot serve the load, APS would see the remaining customer need in its IRP planning process and create a cost to non-participating customers to be able to cover the unserved need. As described earlier, from a long-term planning standpoint, WRAP-based RA resources cannot yet be fully depended on for reliable service to APS customers given that the current WRAP membership has not yet achieved RA compliance. Ultimately, APS is responsible for reliable service and differences between load and RA capabilities lean on non-participating customers to cover the difference.

In addition, customers providing GSP-supplied energy with RA would only be obligated to provide the RA for WRAP-defined seasons (which lasts for approximately seven months from June 1st to September 15th for the Summer season and November 1st to March 15th for the Winter season). However, they pay $0 to APS for generation capacity supplied on a year-round basis. In this circumstance, these customers would be leaning on APS to provide RA outside the WRAP-defined seasons, while costs for RA-characteristic generation capacity would remain with non-participating customers outside of the WRAP-defined seasons. APS must maintain reliable resources year-round. While currently there are no customers providing energy with RA characteristics, APS recognizes the unintended gap in structure.

Q. UNDER THE AG-X PROGRAM, IS APS ABLE TO COLLECT THE COSTS ASSOCIATED WITH RESOURCES PROCURED TO SERVE A CUSTOMER ONCE THEY LEAVE THE PROGRAM?

A. The AG-X program does not currently contemplate recovery for costs already incurred when a customer joins the AG-X program. These are resources and services these customers will no longer be contributing to fund, notwithstanding the benefits of those resources and services they received when they were a non-AG-X customer. For example, hedge volumes that mature after a customer joins the AG-X program were purchased contemplating the customer's need. In the predecessor program to AG-X, AG-1, customers were responsible for paying any mark-to-market losses when they joined the program. This payment prevented the loss of any hedge cost associated with the customer joining the program, which avoided hedge-related cost shifts. Similarly, today the PSA has an uncollected balance of approximately $105 million.[16] These costs were incurred to serve existing customers and are yet to be collected. However, if a current APS customer joins the AG-X program, they will no longer contribute to paying back the costs incurred to serve them and those costs will be paid by other customers.

Q. WHAT DETERMINES WHETHER THERE IS SUFFICIENT TRANSMISSION AVAILABLE TO DELIVER OUTPUT FROM AN AG-X CUSTOMER'S GSP-BASED RESOURCE TO APS'S LOAD?

A. APS determines this through its transmission planning and study processes, which evaluate whether sufficient firm, non-interruptible transmission capacity is available along the delivery path between a given resource and APS load. This assessment includes any required third-party transmission for off-system resources (*i.e.,* those resources outside of APS's transmission footprint delivered to the

[16] The value of the PSA uncollected balance is current as of February 2026 and is subject to change.

Company for the benefit of customers). The process is performed pursuant to open access requirements established by the Federal Energy Regulatory Commission (FERC) and, as a result, APS is treated the same as all transmission customers.

Q. WHAT GAPS DOES THE CURRENT AG-X PROGRAM HAVE WITH RESPECT TO TRANSMISSION RESERVATIONS?

A. AG-X generation is delivered to the Palo Verde hub and requires reserved transmission capacity on APS's system to serve participating customers. Transmission in this area is constrained and highly valued due to the concentration of interconnected, low-cost generation in that area. These transmission reservations for AG-X energy are in addition to transmission needed for APS to deliver RA resources to the same customer. This results in less transmission available to support growth for new customers.

GSP-provided RA does not necessarily resolve the inefficient use of transmission (*i.e.,* one path for customer energy, one path for APS-supplied RA generation). This is because the RA may be delivered elsewhere on the system and APS must still reserve the specified transmission to allow for customers to transition between APS- and GSP-provided RA. In either case, the AG-X program results in the duplicative and inefficient use of transmission resources.

Q. WHY CAN'T DEMAND RESPONSE BE USED TO REDUCE AG-X CUSTOMERS' GENERATION CAPACITY CHARGES ON A PROPORTIONAL BASIS WHEN RA IS PROCURED BY APS?

A. Proportional adjustments of the type recommended by Mr. Lance Kaufman would be inappropriate and would not be in the best interest of non-participating customers.[17] Demand response is typically a short-duration resource designed to address limited periods of peak need. Its capacity value is derived from the

[17] Kaufman Direct at 23-24.

availability of other generation resources that have excess capability to serve load outside those short peak periods. As a result, the capacity accreditation associated with demand response relies on the presence of baseload, intermediate, and peaking resources that provide sustained and dispatchable capability. Applying a generation capacity reduction on a one-for-one basis improperly values demand response as if it provides reliability contributions comparable to those conventional generation resources upon which it depends.

Moreover, a one-for-one credit fails to account for the fact that generation capacity charges recover the costs of resources needed not only to serve load, but also to maintain a planning reserve margin. Proportional adjustments, therefore, overvalue capacity reductions, even if the underlying resource has greater operational capability than demand response, and would result in an inappropriate cost shift to non-participating customers.

Q. WHY DOES APS NOT SUPPORT EXPANDED AG-X ELIGIBILITY FOR XHLF CUSTOMERS?

A. A number of intervenors, such as Phoenix Hydrogen Hub, LLC (PHH), NRG, and Calpine Energy Solutions, LLC, advocate for allowing customers to take service under rate schedule XHLF, specifically data centers, to participate in the AG-X program. The Company does not support making this change at this time, and APS would only support expanding AG-X eligibility to XHLF customers if existing gaps in the program were addressed (as described above). As high energy users, XHLF customers would shift the most costs to other customers through existing gaps in program participation. The Company would not support expanded eligibility to XHLF customers because of the following gaps:

- GSP-provided RA is not capable of meeting expected customer demand year-round on an 8,760-hour basis to fully match customer load, which

limits how much short-duration RA resources lean on other resources not being paid for their accreditation. WRAP remains an important third-party for setting required obligations for planning reserve margins and resource accreditation, but it cannot be solely relied upon to establish GSP-supplied RA. XHLF customers have sustained high energy demands that necessitate increased energy supplied by RA resources and are not adequately served by short-duration resources.

- GSP-provided RA is not provided year-round—*i.e.,* in all seasons of the year, not just the defined "WRAP seasons"—consistent with the reliability needs of customers, along with the bill adjustments for generation capacity these customers receive. XHLF customers have almost zero seasonal variability and retain high demands on the system outside WRAP-defined seasonal periods;
- APS-provided RA does not include charges to recover PPA-related costs currently recovered in Base Fuel and any growth-related direct assignments of PPA costs recovered in the PSA, which in both cases provide system-wide RA. XHLF customers significantly contribute to the increase in Base Fuel costs and the AG-X program should not be a means to leave behind RA fixed costs associated with existing or growth-related service; and
- Costs recovered through the PSA, which would otherwise be incurred for past or future service, do not include a buyout provision to make non-participating customers whole as customers transition to the program. Specifically, any negative hedge-related positions or uncollected PSA balances incurred for the specific customer do not have a mechanism to recover costs and credit non-participating customers.

Other gaps in the AG-X program design, like those of transmission requirements, are not especially exacerbated from customers with high energy demands like those of XHLF.

C. AG-X Program Expansion

Q. DO YOU SUPPORT EXPANSION OF THE AG-X PROGRAM?

A. No. Putting aside that the program is approximately 50% subscribed, expansion of the AG-X program is not in the best interest of non-participating customers. In addition to the gaps in the program design discussed earlier, the AG-X program creates planning and operational complexity that grows with the program size.

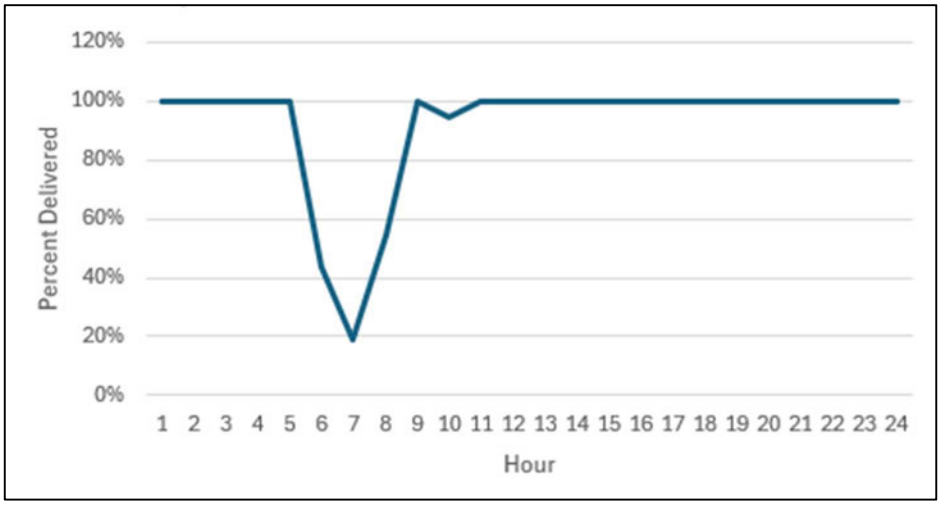
Q. BASED ON THE CURRENT TERMS OF THE PROGRAM, WHAT ARE RELIABILITY RISKS APS CUSTOMERS WOULD FACE UNDER AN EXPANDED AG-X PROGRAM?

A. Curtailments of AG-X supplies can create operational challenges that adversely affect system reliability and can impose costs on customers who do not participate in the AG-X program. In 2025, AG-X supplies experienced curtailments of up to 81% in a single hour. At the program's current size, such a curtailment resulted in a loss of approximately 70 MW of energy being delivered to the APS system.

If the AG-X program were to expand to 1,000 MW, as suggested by Mr. Kaufman,[18] an 81% curtailment would equate to an approximate 810 MW loss of supply (*see* Figure 3). A loss of that magnitude would require APS to rapidly commit additional generating resources to maintain system balance. Unlike conventional generation resources, AG-X supplies do not return to the system in a coordinated manner following a curtailment, which increases the risk of further operational disruptions.

[18] Kaufman Direct at 14.

Figure 3. April 7, 2025 AG-X Deliveries to Schedule



This risk is exacerbated by the operational characteristics of generation resources, including minimum run times and minimum down times once a unit has been committed or decommitted. As a result, both the risk of supply loss and the complexity of system recovery increase substantially as the AG-X program grows, with potential reliability impacts borne by all APS customers.

Separately, for AG-X participants with GSP-supplied RA, if for any reason that RA experienced a delivery failure or the GSP otherwise ceased providing RA, APS is obligated to continue serving that customer with the same level of reliability provided to non-AG-X customers. Accordingly, if a participating customer is unable to secure RA from a GSP, APS must still provide a full reliability backstop for that customer, which increases costs and reliability risks for all other non-participating APS customers. Today, at the current program size of 200 MW, that problem poses low risk to APS customers. But, if expanded to 1,000 MW, that problem could pose potentially unacceptable reliability and cost shift risks to non-AG-X customers.

Q. DO YOU AGREE WITH MICROSOFT CORPORATION (MICROSOFT) WITNESS MARK E. GARRETT AND MR. KAUFMAN THAT EXPANSION OF THE AG-X PROGRAM CAN BE A SOLUTION TO SIGNIFICANT CUSTOMER LOAD GROWTH?[19]

A. No. Expansion of the AG-X program works against the "growth pays for growth" principles APS is proposing in this case. Moreover, the AG-X program does not address the limiting factors for growth within APS's service territory, which go beyond the simplified structure of the AG-X program and concern the broader regional gap in available generation resources (as described in more detail by APS witness Jacob Tetlow). Expanding the AG-X program on its own will not bring about the existence of additional generation resources and associated transmission infrastructure needed to serve growth. Existing and unprecedented demand for new electricity service is already signaling to the market a need for new resources—expanding AG-X does nothing to change this dynamic. In fact, the current design of the AG-X program requires APS to reserve an additional 200 MW of transmission for RA resources to support the program resulting in an inefficient use of transmission. As a result, expansion of the AG-X program reduces the available transmission for resource development making expansion counterproductive from the standpoint of serving additional growth on APS's system.

Moreover, as described above, there are numerous ways in which an expanded AG-X program exposes existing, non-AG-X customers to increased risks of cost shifts and reliability events. Even without expansion (as similarly described above), the

[19] Microsoft, Direct Testimony of Mark E. Garrett (Mar. 2, 2026) (Garrett Direct) at 21-22; Kaufman Direct at 14-15.

current program design also features a number of gaps that still shift considerable costs to existing non-AG-X customers.

Q. WHAT OTHER COMPLICATIONS ARE THERE TO AN EXPANSION OF THE AG-X PROGRAM?

A. Any expansion of the AG-X program is complicated by the need to reserve transmission rights and ensure that necessary transmission capacity exists to facilitate the delivery of GSP-supplied energy and capacity to APS's load. As described earlier, each MW of AG-X program growth can remove multiple MWs of the limited transmission available from meeting growth. As a result, the expansion of the current program would be counterproductive from the standpoint of serving additional APS customer load growth.

D. "Sleeves" and Behind-the-Meter Generation

Q. ARE MR. GARRET'S SLEEVE AGREEMENT AND BEHIND THE METER GENERATION PROPOSALS REASONABLE SOLUTIONS TO SERVE LARGE LOAD CUSTOMERS?

A. Sleeving Agreements and behind the meter solutions can be part of a portfolio of resources to maintain reliability, provided they are carefully crafted to ensure RA, transmission delivery, fuel availability, and the matching of resources to load needs. While APS works with customers on alternative approaches like the ones Mr. Garrett recommends,[20] these alternatives are complex and without careful consideration could shift costs and long-term risks to existing customers.

Q. ARE THERE ANY IMPORTANT CONSIDERATIONS THAT MUST BE ADDRESSED WITHIN "SLEEVE" ARRANGEMENTS?

A. As is the case with AG-X, "sleeve" arrangement solutions can fail to contemplate changed circumstances from when they were initially established. For example, several years ago, the industry was seeking solutions to short-duration peak needs.

[20] Garrett Direct at 18-20, 23-24.

As short-duration solutions (energy storage, demand response, etc.) developed, yet customer needs for 24/7 power grew, longer and longer-durations of resources became necessary in order to accommodate growing customer demand. As a result, the types of risks and customer needs changed to longer-duration resources with corresponding needs for fuel and associated infrastructure (*e.g.,* requiring the development of new pipeline capacity). While such new resources and infrastructure are necessary to ensure grid reliability for all customers as the system grows, customers locked into a "sleeve" arrangement may not be sharing in the additional costs needed for a reliable system. In this respect, "sleeve" arrangements can lock a customer into a moment in time and prevent them from sharing costs and risks as circumstances change in the future.

Additionally, sleeve arrangements can create more competition over limited available generation and pipeline resources, which reduces the number of solutions available to meet new and existing customer needs and also raises prices in the marketplace. While a sleeve arrangement may help advance the interests of one or a handful of participating customers, that progress may come at the expense of other APS customers that are not beneficiaries of such an arrangement.

Q. WHAT ARE SOME IMPORTANT CONSIDERATIONS THAT MUST BE ADDRESSED WITH BEHIND-THE-METER GENERATION SOLUTIONS?

A. Resource duration as compared to overall system needs must be considered to ensure that any behind-the-meter generation solution offers meaningful reliability benefits. While each potential behind-the-meter resource opportunity is different, often resources are for short-durations (sometimes less than 500 hours) leaving the remaining 8,260 hours a year to be met with other system resources, most likely supplied by APS. In seeking to leverage these opportunities, APS works with

customers to understand the nature and scope of the generation opportunity and seek mutual benefit for the customer and non-participating customers. While APS has been successful in working with customers to help develop three customer-sited projects, as examples of these opportunities, each customer project is different and will present unique challenges.

Overall, the kinds of potential solutions offered by Mr. Garrett may be worth exploring on a one-off basis, based on the characteristics of each opportunity. However, because of the unique needs of each customer and the evolving challenges of managing a rapidly expanding system, these measures are not broad solutions to address large, high load factor customer growth. Careful coordination and planning are needed to ensure these arrangements do not create cost shifts or transfer risks to non-participating customers while not creating yet another variable to make a difficult challenge more complicated. Nonetheless, APS will continue to work with customers on these and other opportunities as they become available.

V. SECOND REDHAWK MWSP

Q. CAN A DUAL-UNIT REDHAWK OUTAGE BE REPLACED BY ALTERNATIVE RESOURCES?

A. No, not without significant reliability risk. As described in Mr. Tetlow's Rebuttal Testimony, the construction of a second MWSP was necessary in order to avoid a prolonged fall, winter, and spring outage of Redhawk, which previously operated with only one MWSP. An additional MWSP was necessary in order to ensure reliable, year-round operations from Redhawk.

Reliable service to customers is more than simply matching a forecasted balance of energy to customer demands. Criteria for optimizing and dispatching resources includes the need for flexible resources that account for forecast variances on load

and resources, ramping inside the hour, and moment-to-moment fluctuations in customer usage. Collectively, these functions are referred to as "regulation." Without flexible resources of the kind provided by Redhawk, APS cannot sufficiently regulate generation output and maintain reliable operations.

Q. WHAT IS THE NATURE OF THE FLEXIBILITY OFFERED BY A POWER PLANT LIKE REDHAWK AND WHAT VALUE DOES IT DELIVER TO THE APS GRID?

A. Flexibility is critical to operating a balancing authority, like the one APS operates within its service territory. So much so that the WEIM measures a portion of flexibility every hour to determine whether a Balancing Authority Area (BAA) can participate in the market. Failure to meet flexibility criteria locks a participant out of the WEIM to prevent reliance on other market participants.

APS has three large, combined-cycle resources, two of which are at Redhawk, that serve as the primary source of this critical flexibility outside the summer months for the Company's BAA. A sustained dual-unit Redhawk outage for all of the fall, winter, and spring months would pressure the third large combined-cycle at APS's West Phoenix Power Plant (West Phoenix) to operate continuously to provide flexibility services for the entire period. This would then prevent the West Phoenix resource—which, similar to Redhawk is critical for maintaining reliable service during the summer in APS's service territory—from receiving maintenance to prepare for the next critical summer period. As such, a dual unit outage at Redhawk not only threatens APS's ability to provide key flexibility and regulation during fall, winter, and spring months, but it also puts reliability at risk over the critical summer period.

Market purchases are an effective replacement for energy; however, they do not create the flexibility to reliably meet the moment-to-moment needs of customers. In this respect, a prolonged outage of both generating units at Redhawk, even during the fall, winter, and spring months, would subject APS customers to unacceptable reliability risks.

VI. RESIDENTIAL DG STUDY

Q. PLEASE EXPLAIN THE BACKGROUND AND APPROACH TO SUBMITTING A REPLACEMENT COST STUDY FOR RESIDENTIAL DG.

A. Pursuant to Decision No. 79293,[21] APS submitted an analysis of what its system would have looked like without residential DG and how much more the Company would have spent on generating capacity, fuel costs, and market purchases to backfill the DG resource, compared to APS's actual Test Year costs (Test Year is the 12-month period ending December 31, 2024). APS used a production cost model to study the most economic dispatch of available resources to meet customer demands. The model used actual resource availability, load, and market prices during the Test Year. The model mirrors operational dispatch, solving for energy and ancillary service needs (contingency and flexibility). APS began by performing a base case study including all DG production and the expense paid for solar exports as solved by the production cost model. APS used the base case to compare against two bookend cases that reflect an upper and lower bound of replacement costs for the Commission to consider.

For purposes of estimating replacement costs, APS included the full amount of DG production that would have been needed to replace the absence of DG production.

[21] Decision No. 79293 at 448.

In both scenarios, the replacement costs were significantly lower than the $126.1 million solar credit value referenced in Mr. Moe's Rebuttal Testimony.

Q. PLEASE DESCRIBE THE LOWER BOUND STUDY AND RESULTS.

A. APS performed the lower bound study in direct response to the Commission's request assuming there were no DG resources during the Test Year. The scenario removed all DG production. The model then served energy using market purchases to replace the DG resources only during periods in which either the system had insufficient resources or it was economic to do so. In other words, in the absence of DG, the model assumed that APS could rely on optimized output from existing APS resources. Only when those resources weren't otherwise available, or it was more economic to use alternatives, would the model select market energy purchases to fill-in for the absence of DG production. Some months were identified by the Production Cost Model to have shortfalls without the DG resources, specifically January, April and October. The shortfalls were attributable to planned maintenance on other APS generation resources during the timeframe. These months also included a premium charge to reflect RA characteristics above the energy-only wholesale market prices.

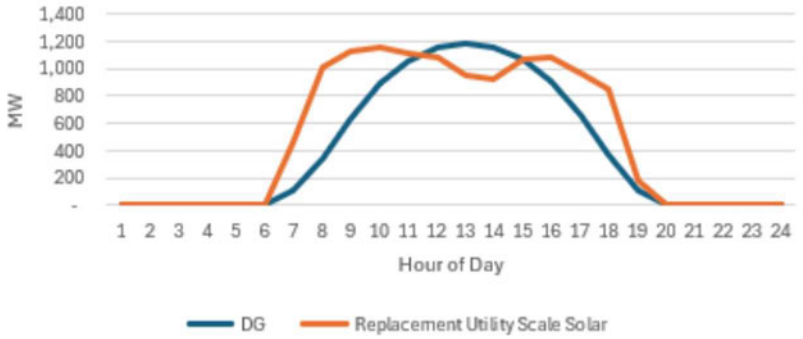
Replacing DG with market purchases resulted in a cost of $54.9 million (as compared to the $126.1 million cost in the Solar Credit value).[22] The lower replacement costs are primarily driven from only purchasing power when needed by the system. Market prices for energy are less expensive than the solar credit value, especially during the hours of DG production, which are among the lowest cost timeframes for market purchases. The results also indicate that the majority of the DG was replaced with other APS resources, not market purchases, which, therefore, indicates APS generally has capacity during the hours of DG production.

[22] APS, Direct Testimony of Jamie R. Moe (June 13, 2025) (Moe Direct) at 28

Q. PLEASE DESCRIBE THE APPROACH TO THE UPPER BOOKEND.

A. APS also performed an upper bound study to reflect a scenario where DG was replaced entirely with physical assets, which in this scenario involved utility scale solar resources. The utility scale solar was sized to match the maximum output of the DG, creating a like-for-like resource replacement. This approach ensures the reliability attribution for the utility scale solar is at least the same as the DG, because utility scale solar produces the same amount of energy when DG is at maximum production. Nonetheless, because the utility scale solar tracks the sun throughout the day, greater amounts of energy are produced in the morning and evening from these resources compared to DG (*see* Figure 4). APS used the price for solar it procured in the 2020 ASRFP as a proxy price for the replacement resource.

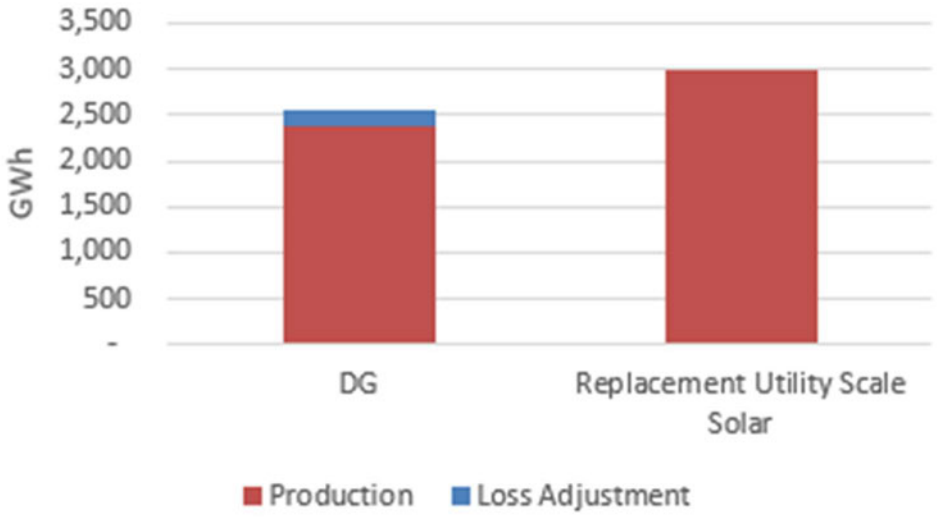
Figure 4. Replacement Utility Scale Solar Sized to Maximum DG – May 6, 2024



The result of replacing DG with utility scale solar was a cost of $71.6 million (as compared to the $126.1 million cost in the Solar Credit value).[23] The lower replacement costs are primarily attributed to: (1) increased total production, particularly during evening hours, and (2) the ability to curtail solar output when it is not required by the system. Overall, production of the utility scale solar was approximately 435,000 MWhs more compared to the DG production (*see* Figure 5).

[23] Moe Direct at 28.

Figure 5. Residential DG and Replacement Utility Scale Solar Production



Q. DO YOU AGREE WITH ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION (ARISEIA) WITNESS KEVIN LUCAS THAT APS'S SCENARIO REPLACING DG WITH MARKET PURCHASES IS UNREASONABLE?[24]

A. No. This scenario represents a reasonable lower bound cost for replacing DG. The loss of DG resources does not trigger a material amount of new capacity-backed purchases needed because the timing of DG production coincides with periods of lower customer demand during which APS already has solar resources. As illustrated in Figure 6, when the DG is removed, APS solar resources already address the daylight hours of customer needs. As DG is then illustratively applied to the remaining consumption in Figure 7, the DG provides only little benefit towards further reducing peak period needs and thus only needs a small quantity of RA backed energy.

[24] AriSEIA, Direct Testimony of Kevin Lucas (Mar. 18, 2026) (Lucas Direct) at 56-61.

Figure 6. 2024 Peak Demand Reduction Addressed by APS Solar Resources

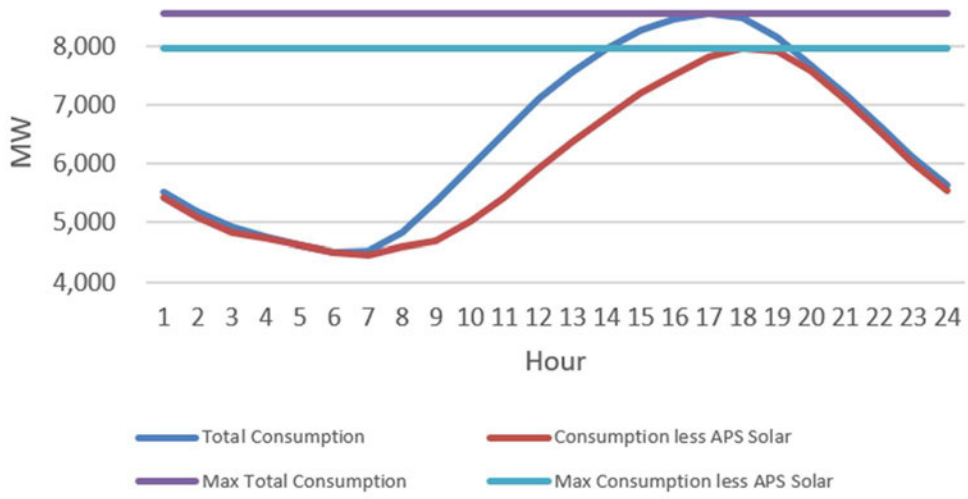
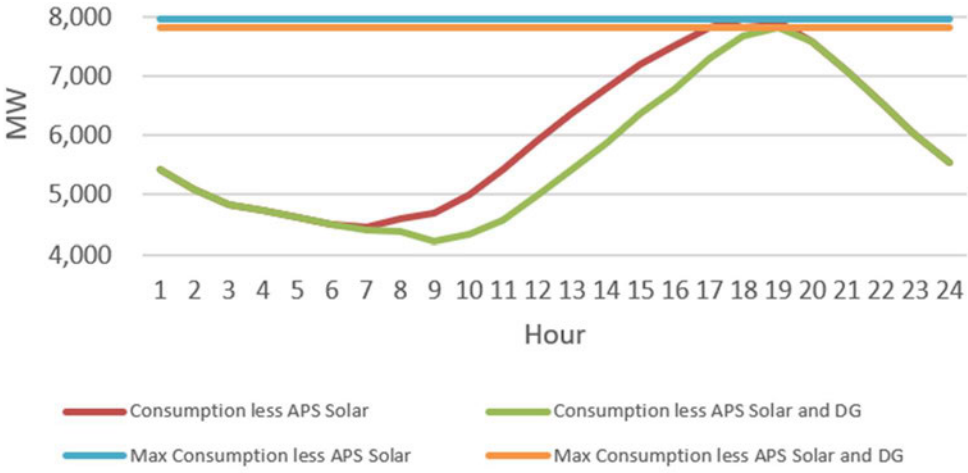


Figure 7. Additional Demand Reduction Benefit From DG - Peak Day 2024



Mr. Lucas references an APS Data Request response in which APS states that it would not rely on short-term market purchases to replace a long-term need. As it pertains to this scenario, over 3.7 GW of solar plus energy storage resources were in development by the end of 2024. As provided in the lower-bookend scenario, APS could rely on short-term market purchases, coupled with optimization of its existing non-DG generation resources, to address near-term resource needs while addressing the long-term need for replacement resources by procuring utility-scale solar plus storage resources.

Q. DO YOU AGREE WITH MR. LUCAS THAT APS'S SCENARIO REPLACING DG WITH UTILITY SCALE SOLAR IS UNREASONABLE?

A. No. This scenario is a reasonable approach to identifying an upper boundary to the value of DG. The approach replaces DG with a like resource that is sized in a manner to ensure at least an equivalency in all reliability characteristics without inserting the complexities of RA accreditation, costs of variable resource intermittency, or other factors that could complicate the topic. That said, I agree with Mr. Lucas that APS would not normally use this simplified approach and would instead size the solar to a smaller scale to more appropriately meet the needs of the system. I also agree with Mr. Lucas that it is possible a more cost-effective resource or mix of resources could be identified. For these reasons, APS presents the scenario as an upper bookend.

APS used actual prices for a resource signed from the 2020 ASRFP to inform the costs for solar generation because this earlier ASRFP reflects the most likely action APS would have taken to address a resource shortfall in 2024. While APS did have other solar resources that went into service in 2024, those resources were selected through a later ASRFP. I agree with Mr. Lucas that prices today are different than those used in the study; however, the prices used in the study are appropriate to evaluate the 2024 Test Year, as ordered by the Commission (*i.e.,* before changes in federal renewable energy tax policy that arose in 2025). The changes in tax policy, tariffs, and new resource costs continue to evolve and always will. Studies reflect the period for which they were performed, which in this case was ordered to be the Test Year, and APS's approach reasonably reflects Test Year costs for replacing DG resources.

Q. WHAT IS YOUR POSITION ON MR. LUCAS' COMPARISON OF APS'S COAL GENERATION AND ROOFTOP SOLAR?

A. Comparisons between coal resource operating profiles and DG are like comparisons between apples and oranges. APS's coal resources possess a degree of operational flexibility that is coordinated with the rest of APS's generation portfolio. Limitations on coal flexibility are intentional and necessary to maintain stable operation so that these units remain available to ramp and serve customer needs after solar production declines in the evening.

By contrast, DG provides no operational flexibility and is enabled by coal and the essential flexibility provided by other APS thermal resources. DG production during periods of system oversupply is limited in its usefulness beyond daylight conditions and cannot be dispatched or shaped to support system operations. In this respect, coal resources are no different than nuclear or combined-cycle resources, all of which serve broader system needs that include providing stable, continuous energy and enabling operational flexibility across the portfolio.

Q. HOW WERE MARKET PRICES INCLUDED IN THE STUDY AND WHY DO THEY DIFFER FROM ACTUAL PURCHASE PRICES DURING THE TEST YEAR?

A. APS used actual market prices as published by the Intercontinental Exchange (ICE) for the Palo Verde hub in its studies. ICE prices reflect weighted-average transaction prices derived from reported trades of standardized, liquid wholesale electricity products at the Palo Verde hub.

These published market prices differ from the average dollars-per-megawatt-hour prices associated with APS's power supply purchases during the Test Year for two primary reasons. First, the summer months (identified as Figures 14 and 15 in Mr.

Lucas' testimony)[25] include purchases with RA characteristics, which command a premium relative to energy-only wholesale market prices. Second, transactions in the daily wholesale market are typically executed using standardized market products rather than hourly-shaped deliveries.

Standard market products are defined blocks of hours that trade at a single price and volume and are the most liquid products at the Palo Verde hub. Examples include on-peak (heavy load) and off-peak (light load) products, each of which settles at a uniform price across the specified hours. As a result, a single transaction price may be higher than prevailing market prices during certain hours, such as mid-day, and lower during other hours, such as evening periods.

As illustrated in Mr. Lucas' Figure 13, the Test Year average reflects this characteristic of standardized market products, which apply a single price across a defined window of hours rather than varying on an hourly basis.[26] APS transacts these liquid, standardized products because they represent the predominant means by which energy is traded at the Palo Verde hub.

Q. DO YOU AGREE WITH MR. LUCAS' CHARACTERIZATION OF APS'S MARKET PURCHASES?

A. No. It is incorrect to suggest that RA market purchases used to ensure reliability were only needed a handful of days.[27] APS's RA resources are procured to manage uncertainty and ensure reliability across a broad range of system conditions, including extreme heat, resource performance risk, and transmission outages—not solely to meet energy needs on peak days.

[25] Lucas Direct at 59-61.
[26] *Id*. at 59.
[27] *Id*. at 37, lines 17-19 ("In other words, there were only a handful of days in each month in which this expensive power was actually needed to meet load…"*)*.

Such resources also provide value through their interaction with the rest of the system. By meeting a portion of system requirements, these resources reduce the burden on other units, allowing those units to be positioned to provide essential flexibility, including response to forecast error, load ramping, and real-time balancing. That flexibility is critical prior to operations, when many operational variables are still unknown. During real-time operations, depending on the specific system conditions and needs on the grid, the same capability may result in surplus energy that can be economically resold to offset customer costs.

Q. IS IT REASONABLE TO CREDIT DG BASED ON THE AVERAGE MARGINAL COST OF PURCHASED POWER FROM WHOLESALE MARKETS?

A. The premise underlying Mr. Lucas' proposal assumes that market purchases would directly replace DG. While that assumption is directionally accurate, it fails to account for fundamental differences between market purchases and DG, particularly with respect to the timing of customer needs and the characteristics driving system costs.

As illustrated in Figures 6 and 7above, DG provides relatively limited support during periods of peak customer demand because APS's existing resources already address daylight energy needs. On July 10, 2024—the example day referenced by Mr. Lucas—if DG is removed from load, and APS solar resources are applied, the remaining system peak occurs between 6:00 p.m. and 7:00 p.m. These hours occur well after the reference period used by Mr. Lucas and coincide with a time when DG production is minimal. The primary cost driver associated with market purchases during these hours is not energy volume, but the fixed costs required to procure RA characteristics from resources capable of serving load into the evening. DG is not a comparable substitute for these market purchases.

This conclusion is further supported by the upper-bound study, which demonstrates that a like-for-like replacement of DG with utility-scale solar would cost approximately $71.6 million, or $0.0302 per kilowatt-hour—roughly 70% lower than the rate proposed by Mr. Lucas. Notably, this analysis did not attempt to economically optimize the size of the solar resource or evaluate alternative resource combinations that could have further reduced replacement costs.

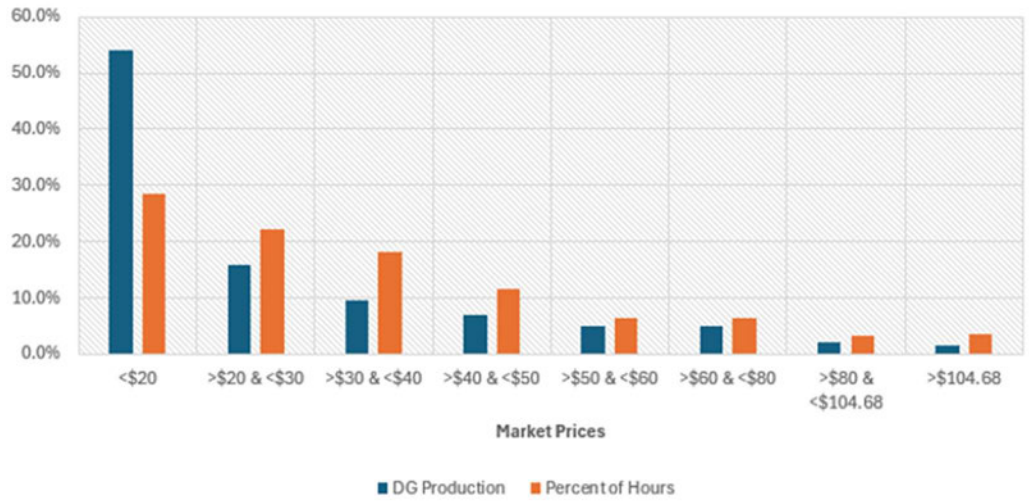
Market purchases are also not an appropriate long-term valuation benchmark. To the extent the absence of DG was to create a sustained resource need, market purchases would serve only as a temporary bridge while long-term resources are developed. They are not a proxy for long-term system value and should not be used as such for valuation purposes.

Moreover, DG is not developed through an IRP process that identifies specific system needs or reliability objectives. Market purchases, by contrast, are executed to address defined system requirements until long-term resource solutions are developed, or to capture economic benefits when market conditions are favorable. Treating DG and market purchases as interchangeable, therefore, overlooks the fundamentally different roles they play in system planning and operations.

Finally, a generalized reference to market purchases does not reflect the timing of DG production or its actual system value. Market prices are driven by supply and demand, with higher prices reflecting scarcity and lower prices reflecting periods of abundance. As shown in Figure 8, the majority of DG production occurs during hours when market prices are below $20 per megawatt-hour ($0.02 per kilowatt-hour), even though only 28% of hours in 2024 experienced prices at or below that level. This alignment demonstrates that DG production is concentrated

in periods of excess generation, further underscoring that average or market-based cost metrics materially overstate the value DG provides to the system.

Figure 8. 2024 Market Pricing Compared to DG Production



Q. WHY DIDN'T THE COMPANY EVALUATE TRANSMISSION AND DISTRIBUTION (T&D) SYSTEM COST IMPACTS IN THE DG STUDY?

A. APS did not include an analysis of avoided T&D costs because it was not requested by the Commission and is not a significant value driver. I disagree with Mr. Lucas and Vote Solar witness Kate Bowman's statements that APS's submitted study is "flawed" or "not methodologically sound" without an analysis of T&D value; however, to be responsive to these comments, I sponsor a study of costs on the distribution system that may have been avoided as a result of DG output reducing the loading on the distribution system. A distribution study was selected as it is closest to the DG and would demonstrate the greatest impact to consider materiality of avoided T&D.

The analysis is a feeder-by-feeder and transformer-by-transformer analysis of the line loading with, and without, the presence of DG. The analysis included all 1,100 feeders known to have DG and the 451 substation transformers for the feeders

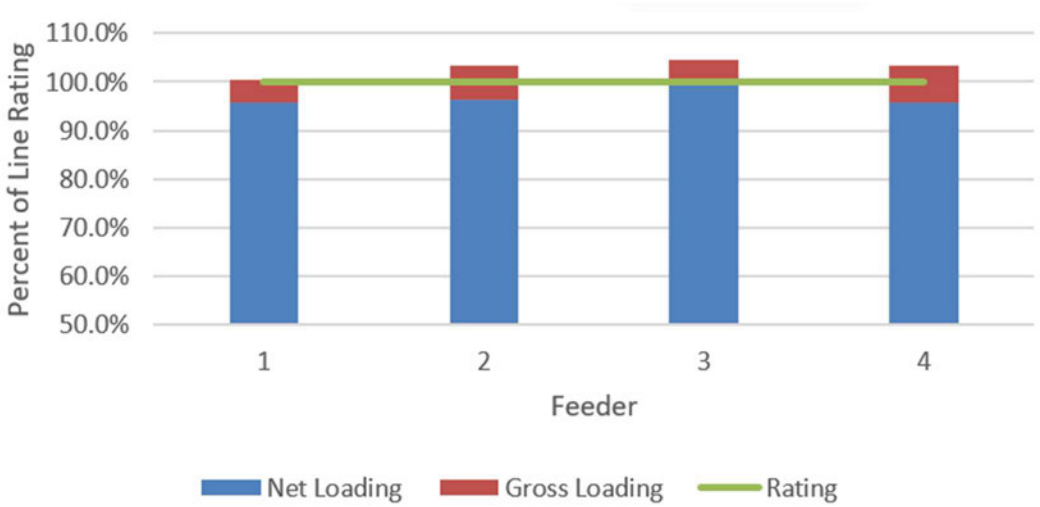
during the Test Year. The equipment was evaluated for its current line loading (net loading) and what the line loading would have been without DG (gross loading). The analysis identified four feeders that may have had line upgrades deferred for one to three years. The total present value of those deferrals is approximately $3 million. Given the range of replacement costs produced by the lower and upper bookend studies—between $54.9 million and $71.6 million, respectively—this $3 million cost added to both cases does not measurably change the outcome of the Company's analysis.

Q. WHAT WAS THE METHODOLOGY FOR CALCULATING THE POTENTIAL $3 MILLION DISTRIBUTION DEFERRAL?

A. APS conducted a review of feeders and transformers to identify instances of gross loading exceeding 100% of the equipment's rating, while net loading remained below 100% of its rating, with the absence of DG. Four feeders and zero transformers were identified as potentially having an upgrade deferred as a result of DG.

APS then assessed the number of years the upgrade could likely be deferred because of DG and then estimated the cost to address the feeder loading based on the feeder locations. All identified feeders had net loading in the range of 95% to 99%, meaning that with typical growth factors, an upgrade would likely be needed in one to three years regardless of DG (*see* Figure 9). APS then calculated the net present value of each upgrade deferral based on the timing of the feeder upgrade and assumed a 2% growth rate.

Figure 9. DG Distribution Feeder Loading



Q. DID APS PROVIDE SUFFICIENT DATA TO SUPPORT THE LOWER AND UPPER BOOKEND DG REPLACEMENT STUDIES?

A. Yes. Mr. Moe provided an initial workpaper supporting the study upon filing his Direct Testimony and the Company has responded to numerous discovery requests related to the study throughout the eight-month period during which discovery has been permitted. Based on the detail provided in the initial workpaper, coupled with the exhaustive discovery performed by intervenors, APS provided sufficient detail for the parties in this proceeding to scrutinize the DG replacement studies and their comparisons with Test Year outcomes that included DG resources. This is more than evident given the testimony provided by intervenors critiquing APS's analysis. As such, the Company maintains that the study performed is adequate and demonstrates that the solar credit value used in the Site Load Cost of Service Study, which is explained in Mr. Moe's Direct and Rebuttal Testimonies, is reasonable.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

REBUTTAL TESTIMONY OF CHRIS R. BAUER

On Behalf of Arizona Public Service Company

Docket No. E-01345A-25-0105

April 3, 2026

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REBUTTAL TESTIMONY OF CHRIS R. BAUER
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-25-0105)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Chris R. Bauer. I am the Vice President and Treasurer for Arizona Public Service Company (APS or Company), a subsidiary of Pinnacle West Capital Corporation (Pinnacle West), and my business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address the importance of a financially stable utility to support the customers APS serves and to rebut intervenor testimony that implicates the Company's financial stability. I emphasize how capital structure, cost of capital, and credit stability form the foundation of the Company's ability to provide safe, reliable, and affordable service to customers. I will also highlight the importance of a formula rate in maintaining financial stability amidst a backdrop of significant customer growth and the required infrastructure investment necessary to support and serve both new and existing customers.

I do not address every detail related to Utilities Division Staff (Staff) of the Arizona Corporate Commission (Commission) and intervenor recommendations, and it should not be interpreted that I agree with any of their positions unless specifically stated in my testimony.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. I address the importance to customers of APS's continued ability to meet its operational and business objectives while maintaining the Company's financial stability. In order to provide safe and reliable service to customers at the lowest cost possible, reducing regulatory lag, maintaining a balanced capital structure, and securing the opportunity to earn a fair and reasonable Return on Equity (ROE) and Fair Value Increment (FVI) are all vital. These critical components holistically provide financial stability for APS, allow the Company to maintain or improve existing credit quality, and access to capital through all economic conditions, which directly impact how much it costs to serve customers. Current economic conditions reflect a persistent level of elevated volatility, restrictive Federal Reserve measures, and capital market uncertainty amid global conflicts and shifting trade policy. In this environment, APS's financial stability remains the foundation of providing long-term reliable and affordable service for customers.

I will also highlight how the implementation of a formula rate for APS is necessary to achieve the objectives stated above. Both customers and the Company are continuing to face delays in accumulated rate adjustments and considerable delays in recovery, due to Arizona's historical test-year ratemaking system. Regulatory lag is even more impactful to the Company and customers during periods of high inflation and rising interest rates, coupled with persistent capital market volatility and unprecedented system growth. The implementation of a formula rate for APS has the dual benefit of allowing APS the opportunity to pass on cost savings to customers while also improving timeliness of investment recovery.

III. IMPORTANCE OF A FINANCIALLY STABLE UTILITY FOR CUSTOMERS

Q. SINCE APS'S RATE CASE WAS FILED IN JUNE 2025, HAVE ANY CONDITIONS ARISEN THAT EXEMPLIFY THE IMPORTANCE OF MAINTAINING FINANCIAL STABILITY?

A. Yes. Since APS filed its rate case application in June 2025, conflicts in the Middle East have increased market volatility and prompted investors to reassess risk, contributing to higher borrowing costs and tighter capital availability. As a capital-intensive utility, APS may face higher costs and less flexibility in the timing of debt and equity issuances needed to fund operations and long-term investments. Strong financial stability helps APS compete for capital in volatile markets and helps limit financing costs, which are ultimately borne by customers.

Q. IN LIGHT OF THESE CONDITIONS, WHY IS APS'S FINANCIAL STABILITY SO IMPORTANT FOR UTILITY CUSTOMERS?

A. APS must make substantial long-term investments to provide safe, reliable service. Because APS operates with negative free cash flow, and regulatory lag delays recovery of those costs in rates, APS must finance investments up front through the debt and equity markets. Financial stability, supported by timely cost recovery, adequate operating cash flow, a balanced capital structure, a fair ROE, and strong credit quality, reduces external financing needs and helps APS access capital on reasonable terms at the lowest feasible cost for customers.

More timely alignment between rates and APS's investments and costs supports the Company's recovery of those costs and the reasonable opportunity to earn its authorized return. That, in turn, supports cash flow and credit metrics, which underpins access to both the debt and equity capital markets. A balanced capital structure and fair and competitive ROE provide the earnings and cash-flow support needed to sustain a strong credit profile.

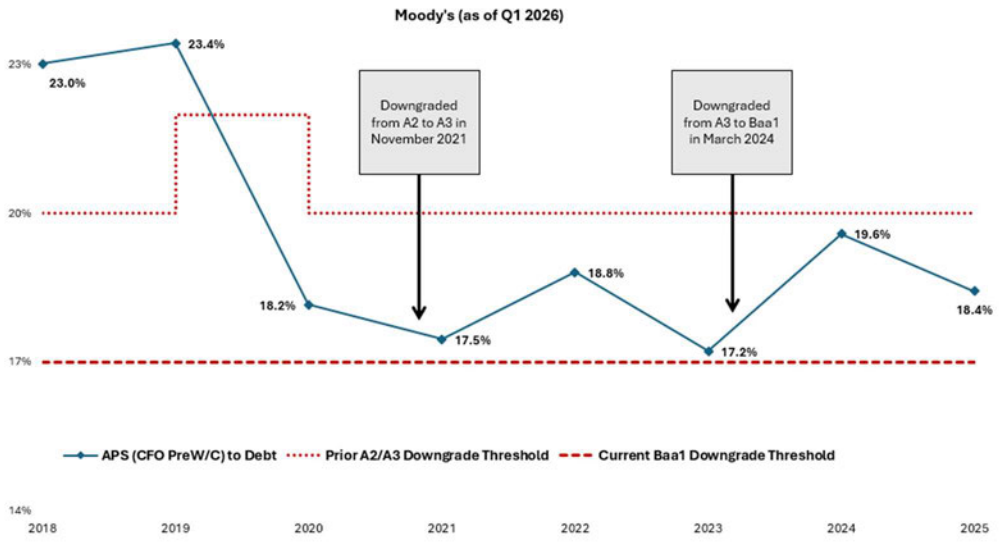
Q. WHY ARE STRONG CREDIT RATINGS IMPORTANT DURING PERIODS OF MARKET VOLATILITY?

A. In volatile markets, investors typically prefer "issuers" with stronger credit profiles. Maintaining APS's investment-grade ratings broadens the potential investor base and generally lowers borrowing costs, even during periods of market stress. While APS can access capital today, volatility can affect timing and pricing; strong credit quality and a stable regulatory framework help APS finance needed infrastructure reliably and at lower cost for customers.

Q. HAS THE COMPANY EXPERIENCED MISALIGNMENT IN CASH FLOWS DUE TO REGULATORY LAG THAT HAS BEEN HARMFUL?

A. Yes. Regulatory lag creates a cash-flow mismatch: APS must fund significant investment while rate recovery trails, which can pressure cash-flow credit metrics and reduce financial flexibility. APS's experience reflects this pattern—new rates in late 2021 and early 2024 temporarily improved metrics, but as regulatory lag re-emerged and capital investments grew to support a growing service territory, cash-flow metrics declined toward downgrade-sensitive levels (*see* Figure 1).

Figure 1. Adjusted Cash Flow From Operations Before Changes in Working Capital (CFO pre-WC) to Debt Ratio



This is why timely cost recovery is central to financial stability: when recovery lags investment, credit metrics deteriorate quickly; when recovery is timelier, metrics generally stabilize or even improve, and financing costs are better contained. Overall, this reduction in financing costs is a direct benefit for customers.

IV. BENEFITS OF A FORMULA RATE

Q. DO FORMULA RATES GUARANTEE THAT A UTILITY WILL EARN ITS COMMISSION-AUTHORIZED RATE OF RETURN?

A. No. A formula rate does not guarantee that a utility will earn its authorized rate of return. Specifically, APS's proposed Formula Rate Adjustment Mechanism (FRAM) is still based on a historical test year framework, which means that any annual rate adjustments are determined by actual historical costs and revenues in the year before updated rates would take effect. In that subsequent year, once the FRAM adjustment takes effect, actual earnings remain subject to numerous factors outside of management control, including weather variability, customer usage patterns, inflationary pressures, and changes in interest rates. Each of these factors, among others, impact the actual costs incurred and revenues collected by APS. For example, even after a FRAM adjustment takes effect (either increasing or decreasing rates), a mild summer coupled with spikes in inflation and interest rates could easily result in reduced utility earnings below the Commission authorized level. Nonetheless, a formula rate helps improve the utility's opportunity to earn the authorized return by reducing the structural mismatch between current costs and rates that exist under a historical test year framework that relies on periodic rate cases.

Q. IF FORMULA RATES DO NOT GUARANTEE EARNINGS, DO THEY REDUCE REGULATORY LAG?

A. Yes. Formula rates reduce regulatory lag by establishing a standardized annual process that more closely aligns rates with the Company's actual cost of service, while preserving a rigorous and transparent framework that includes Commission oversight and stakeholder participation. The annual reset reduces the multi-year delay inherent in Arizona's current rate making and cost recovery framework. It is important to recognize, though, that formula rate mechanisms like the FRAM do not eliminate regulatory lag; they simply reduce it by shrinking the gap in time between when costs are incurred and when those costs are reflected in rates. Given the use of a historical measurement period, regulatory lag still exists, but it is meaningfully reduced.

Figure 2 below demonstrates that, across APS's last four rate cases, there was a substantial delay between the test year period and the point at which the Company was able to begin recovering the level of costs from those test years through rates. It has taken an average of 1,026 days from the first day of the test year and 662 days from the end of the test year to the new rate effective date when new rates are implemented. Under the proposed FRAM, while regulatory lag is not completely eliminated, it is significantly reduced: the rate effective date would occur, on average, 608 days after the first day of the test year and 244 days after the test year concludes.

Figure 2. APS Rate Case Durations

Type	Test Year Start	Test Year End	Rate Effective	Days from End of TY to Rate Effective	Days from Beginning of TY to Rate Effective
Filed GRC	1/1/2010	12/31/2010	7/1/2012	548	912
Filed GRC	1/1/2015	12/31/2015	8/19/2017	597	961
Filed GRC	7/1/2018	6/30/2019	12/1/2021	885	1,249
Filed GRC	7/1/2021	6/30/2022	3/8/2024	617	981
			Average Days:	**662**	**1,026**
Proposed FRAM	1/1/2026	12/31/2026	9/1/2027	**244**	**608**

Q. CAN YOU PROVIDE AN EXAMPLE DEMONSTRATING HOW REGULATORY LAG IS PRESENT UNDER THE CURRENT COST RECOVERY FRAMEWORK WHERE PRUDENT INVESTMENTS ARE NOT RECOVERED IN A TIMELY MANNER?

A. Yes. During a period of regulatory lag, the Company continues to incur prudent costs that are not recovered in rates in effect at that time, as discussed in my Direct Testimony. To further illustrate the impact, Figure 3 below references a hypothetical $300 million capital investment placed in service on October 1, 2023. In this example, the Company would experience approximately $31 million in losses due to unrecovered expenses because of regulatory lag between 2023 and 2026. This example of plant in service exemplifies how regulatory lag materially affects the Company's ability to recover its investments under the current framework, and similar impacts occur across APS's entire business.

Figure 3. Illustrative Example of Regulatory Lag Associated With a Capital Project[1]

$000's	2023	2024	2025	2026
Plant In Service	**$ 300,000**	**$ 300,000**	**$ 300,000**	**$ 300,000**
Accumulated Depreciation	$ (1,235)	$ (8,645)	$ (16,055)	$ (23,465)
Net Plant In Service	**$ 298,765**	**$ 291,355**	**$ 283,945**	**$ 276,535**
Accumulated Deferred Income Tax	$ (2,476)	$ (5,998)	$ (9,117)	$ (11,867)
Net Rate Base	**$ 296,289**	**$ 285,357**	**$ 274,828**	**$ 264,668**
Expense				
O&M	$ 675	$ 2,700	$ 2,700	$ 2,700
Depreciation	$ 1,235	$ 7,410	$ 7,410	$ 7,410
Property Tax	$ -	$ -	$ 4,370	$ 4,259
Total Expense	**$ 1,910**	**$ 10,110**	**$ 14,480**	**$ 14,369**
Income Tax	$ (472)	$ (2,499)	$ (3,580)	$ (3,552)
Post Tax Net Income	**$ (1,438)**	**$ (7,611)**	**$ (10,901)**	**$ (10,817)**
Total 2023-2026 Loss	**$ (30,767)**			

This illustration is also only reflective of capital investments; APS experiences significant regulatory lag anytime expenses for labor, consumable supplies, operations and maintenance (O&M) costs, and other non-capital investments increase above the level then reflected in customer rates. For example, APS witness Elizabeth A. Blankenship discusses how between 2021 and 2025, the Company's historical test year-driven rates have under recovered an accumulated amount of increasing wildfire mitigation O&M expenses by over $90 million.

Q. AARP WITNESS PAUL J. ALVAREZ ARGUES THAT REGULATORY LAG IS A FEATURE BECAUSE IT CREATES INCENTIVE FOR UTILITIES TO CONTROL COSTS. DO YOU AGREE?

A. No. That argument assumes regulatory lag consistently benefits customers and is the best way to encourage utilities to control costs. In reality, regulatory lag delays recognition of prudently incurred costs and can produce larger, less gradual adjustments later, contributing to bill volatility and affordability challenges for customers. Moreover, regulatory lag does not operate symmetrically. When

[1] This illustrative example is intended solely to demonstrate the expense impacts associated with regulatory lag. It does not include and is not intended to include the Company's allowed return on invested capital.

conditions improve in a way that might otherwise result in a benefit to customers, lag delays the rate relief that would flow back to the customers, which can arise from various conditions such as changes in tax policy, lower interest costs, or increased revenue from growth or warmer weather, among other circumstances.

Q. RESIDENTIAL UTILITY CONSUMER OFFICE (RUCO) WITNESS DUSTIN MADSEN SUGGESTS THAT A FORMULA RATE CREATES INCENTIVES FOR A UTILITY TO MAXIMIZE PROFITS BY AVOIDING EFFICIENCIES AND ALLOWING COSTS TO FLOW AUTOMATICALLY INTO RATES. DO YOU AGREE WITH THAT ASSESSMENT?

A. No. That assessment mischaracterizes both the structure of APS's proposed FRAM and the incentives utilities have under Commission oversight. A formula rate does not permit a utility to maximize profits by increasing costs, nor does it allow costs to flow automatically into rates without scrutiny. Under APS's proposal, all costs reflected in a FRAM adjustment remain subject to transparency, stakeholder challenge, and a prudency review. Any costs determined to be unreasonable or imprudent are borne by the Company and its shareholders, not customers.

Further, a formula rate does not change the fact that APS's authorized ROE is fixed by the Commission in a general rate case. Increasing costs does not increase the authorized rate of return and, in practice, can reduce earnings by increasing regulatory scrutiny, increasing disallowance risk, and weakening financial metrics. Inefficient spending, therefore, does not lead to profit maximization under the FRAM.

The profit maximization example discussed by Mr. Madsen is far beyond simply theoretical—it does not, in any way, reflect the reality of how regulated electric

utility companies operate in the real world, where their trusted relationships with customers, investors, and their regulators represents an immensely important aspect of its business. If a utility company ever engaged in the profit maximization strategy that Mr. Madsen describes, the near-term results would likely include severe impacts on the company's credit metrics and earnings, putting its credit ratings at long-term risk. More importantly, coupled with significant disallowances that would almost certainly occur, its trusted relationship with customers, the company's investors, and its regulator would likely be forever damaged. This is not "short-term pain for long-term gain"; instead, this would represent short-term pain and long-term damage that could take a decade or more to repair.

Q. ARE UTILITIES OPERATING UNDER A FORMULA RATE STILL INCENTIVIZED TO CONTROL COSTS?

A. Yes. Customer affordability remains a focused priority that drives the Company's decisions regardless of the ratemaking framework. Under APS's proposed FRAM, costs remain subject to ongoing Commission review to assess prudency on an annual basis. Because approval of an annual update is not guaranteed, the Company continues to have a strong incentive to manage costs efficiently and avoid the risk of disallowance or adverse regulatory action. More frequent, contemporaneous review enhances cost discipline rather than weakens it. This includes APS's proposal, which is discussed in more detail by APS witness Jessica E. Hobbick, to enhance the FRAM with quarterly capital investment reports to the Commission. As such, the FRAM requires APS to make cost, expense, and investment data available to the public on a frequent and regular basis—rather than after years of delay—which increases regulatory scrutiny of APS cost control measures.

Q. WHAT OTHER INCENTIVES DOES THE COMPANY HAVE TO EFFICIENTLY MANAGE COSTS?

A. The Company's incentive to control costs is also influenced by financial discipline that exists independently of the ratemaking framework. Credit rating agencies and investors closely evaluate the Company's cost management, cash-flow stability, and overall financial performance. Poor cost control will weaken credit metrics, increase borrowing costs, and raise the long-term cost of capital ultimately borne by customers. Similarly, investors expect the Company to manage costs prudently in order to achieve its authorized return. Because a formula rate does not guarantee earnings or insulate the Company from the credit rating agencies and investor oversight, these incentives remain fully intact and continue to encourage disciplined management of both operating and capital costs. Inherent cost controls arising from financial market discipline, among other inherent incentives, will continue to ensure that APS operates prudently and efficiently.

Q. DO FORMULA RATES REDUCE FINANCIAL RISK AND IMPROVE CREDIT QUALITY?

A. Formula rates are credit supportive because they improve predictability and cash flow stability through more timely cost recovery. Credit rating agencies and investors generally view mechanisms that support timely cost recovery favorably. However, as APS witness James M. Coyne explains, an improvement in credit quality does not by itself reduce the market-required ROE. Credit risk is only one component of the broader risk assessment.

As explained in Mr. Coyne's Direct Testimony, APS encounters business risks that are higher than those faced by its peers. These risks include lack of diversification, given that the Company operates solely in Arizona and is experiencing unprecedented growth under a historical test year regulatory framework. APS also

faces operational risks from operating the second-largest nuclear power plant in the country, increasing wildfire and excessive heat-related operational and financial threats, and the capital investment execution risk arising from the need to support rapid expansion and industrial customer growth in its service area. These factors continue to impact the Company's overall risk profile and credit evaluation and are not affected by changes in cost recovery structures.

Accordingly, while a formula rate may improve the Company's opportunity to earn its authorized return by reducing regulatory lag, it does not reduce the return necessary to attract and compete for capital, consistent with Mr. Coyne's ROE benchmarking analysis.

Q. SOME WITNESSES RECOMMEND THAT IF THE COMMISSION APPROVES APS'S PROPOSED FRAM, APS'S AUTHORIZED ROE SHOULD BE REDUCED ANYWHERE FROM 15 TO 40 BASIS POINTS. DO YOU AGREE?

A. No. Authorized ROE is set by market evidence applied to a peer group of comparable utilities as evidenced in Mr. Coyne's testimony; the FRAM primarily affects the Company's opportunity to earn the authorized ROE, not the return investors expect given APS's risk profile. The FRAM may improve the timing and predictability of cost recovery by reducing regulatory lag, but it does not eliminate APS's financing or business risks, or the need to compete for capital with other utilities.

Q. DO YOU SUPPORT STRUCTURAL MODIFICATIONS TO THE FRAM PROPOSED BY INTERVENORS, SUCH AS CAPS, EXPANDED DEADBANDS, OR "OFF-RAMPS"?

A. No. Structural limits, such as caps or widened and asymmetric deadbands defer recovery of prudently incurred costs, defeat the purpose of the proposed

mechanism, and reintroduce regulatory lag. "Pilot" terms or off-ramps also introduce regulatory uncertainty that undermines consistency and predictability of ratemaking that is relied on by customers, investors, and credit rating agencies.

Q. HOW IMPORTANT IS PREDICTABILITY AS TO THE TIMING OF FRAM RESETS?

A. Critically important. Because the FRAM is intended to adjust rates for service, cumulative of both operating expenses and capital investments, achieving any meaningful reduction in regulatory lag is directly dependent on consistent timing for achieving these updates. If a given annual update is held up or deferred by consideration of an "off-ramp" or evaluation of a "pilot program" report, which certain intervenors have proposed, APS cannot effectively perform necessary long-term financial planning for essential infrastructure investments. The timing of critical cash flow changes would be consistently called into question.

Q. WHAT DOES THIS MEAN FOR THE COMMISSION'S CONSIDERATION OF WHEN ANNUAL UPDATES TAKE EFFECT?

A. Ms. Hobbick describes APS's current proposal for aligning with certain positions offered by Staff witness Ralph C. Smith concerning the necessity for Commission approval prior to any annual FRAM rate adjustment taking effect. It is important to recognize that APS's consideration of this proposal is necessarily dependent on maintaining the Company's proposed 120-day timeline for FRAM adjustment evaluation and challenges. Doing so, not only allows for fulsome review of annual FRAM adjustments, but it provides necessary consistency and predictability for the timing of any FRAM adjustments taking effect.

Q. SOME PARTIES RECOMMEND THAT ANY FRAM INCLUDE ANNUAL OR CUMULATIVE CAPS ON RATE ADJUSTMENTS. DO YOU SUPPORT THAT PROPOSAL?

A. No. Caps on annual or cumulative FRAM adjustments would materially reintroduce regulatory lag and undermine the core purpose of a formula rate. As I explained in my Direct Testimony, the FRAM is intended to reduce the structural mismatch between when prudent costs are incurred and when they are reflected in rates. Caps would defer recovery of otherwise recoverable costs into future periods, recreating the same lag that the FRAM is designed to mitigate.

Furthermore, a cap materially changes the risk profile of the FRAM. Even if recovery is deferred rather than denied, the Company must finance unrecovered costs for extended periods without timely rate recognition. That outcome increases financial risk and weakens cash flow predictability.

Q. CERTAIN INTERVENORS AND STAFF PROPOSE EXPANDING THE FRAM DEADBAND BEYOND THE ±20 BASIS POINTS REFLECTED IN THE COMMISSION'S FORMULA RATE POLICY STATEMENT AND PROPOSED BY APS. DO YOU AGREE?

A. No. Similar to a cap, significantly expanding the deadband would materially increase regulatory lag by allowing larger under and over recoveries to persist for longer periods before adjustment. Additionally, broader deadband ranges result in larger revenue requirement adjustments when thresholds are eventually crossed, which in turn increases rate volatility for customers.

Q. RUCO, AMONG OTHER INTERVENORS, RECOMMENDS AN ASYMMETRIC DEADBAND. DO YOU SUPPORT THAT APPROACH?

A. No. An asymmetric deadband would introduce structural bias by treating under earnings and over earnings differently as a matter of design rather than

performance. Under the asymmetric deadband proposed by RUCO, a deeper earnings deficiency would be required before APS could adjust rates to recover prudently incurred costs, while smaller earnings excesses would trigger downward adjustments. This one-sided structure presumes that under-earning should be tolerated regardless of the underlying cost drivers or prudence of expenditures.

That structural bias increases regulatory uncertainty by making the timing and magnitude of cost recovery less predictable and more dependent on regulatory design choices than on actual costs and operational performance. By requiring a larger threshold to be crossed before recovery can occur, an asymmetric deadband increases the likelihood that deficiencies accumulate over multiple years, resulting in larger, more sizable rate adjustments when the deadband is eventually breached. This outcome undermines one of the core objectives of a formula rate—smaller, more gradual adjustments—and reintroduces regulatory lag rather than reducing it.

Finally, these effects discourage efficient investment by increasing financing risk and reducing predictability for investors and credit rating agencies. Capital markets value stable, transparent, and durable regulatory frameworks, while an asymmetrical deadband increases perceived regulatory risk and raises the cost of capital. That outcome ultimately disadvantages customers through higher financing costs.

Importantly, APS is not aware of any retail electric formula rate within the United States operating with an asymmetric deadband structure that certain parties have proposed. The absence of precedent underscores the concern that such a design would represent an untested and structurally imbalanced departure from established formula rate practice.

Q. NOTWITHSTANDING APS'S PERSPECTIVE THAT A NARROW DEADBAND IS IMPORTANT FOR RATE GRADUALISM, HAS THE COMPANY CONSIDERED ANY CHANGES TO THE CURRENT STRUCTURE?

A. Yes. While a +/- 50 basis point deadband is too wide, in an effort to move toward compromise with other intervenors and Staff, APS is proposing a +/- 40 basis point deadband, as more specifically described by Ms. Hobbick. A +/- 40 basis point deadband will still prevent significant under recovery of prudent investments and expenditures, thereby minimizing regulatory lag, while also minimizing rate volatility for customers.

Q. IS PROJECTED PLANT STILL NECESSARY UNDER A FORMULA RATE?

A. Yes. Even with the annual rate resets occurring with APS's proposed FRAM, meaningful regulatory lag remains. As previously shown in Figure 2, under the Company's proposed FRAM there is a period of more than 240 days between the end of the test year on December 31 and the effective date of updated rates on September 1 of the following year. During this period, the Company continues to place new plant in service and incur operating expenses that are not reflected in rates. While the FRAM significantly reduces regulatory lag relative to a traditional rate case, it does not eliminate it. The lag that persists includes both: (1) additional capital investment placed in service; and (2) increased expenses incurred during the lag period. Inclusion of projected plant addresses only the capital investment portion of that lag. It does not provide recovery for increased expenses incurred between the end of the test year and the effective date of new rates. As a result, projected plant is not a complete solution to regulatory lag, but rather a targeted mitigant that reduces one side of the regulatory lag equation.

Post-Test Year plant (PTYP) has long been recognized in Arizona as an appropriate and effective mechanism to mitigate the negative impacts associated with the use of a historic test year and the time required to process and implement rate changes. Its inclusion aligns cost recovery with facilities that are providing service to customers when new rates take effect, promotes gradualism through more timely recovery of plant placed in service, and supports regulatory efficiency by reducing pressure for more frequent and less gradual rate adjustments. This is true under both a formula rate and the traditional historical-test year framework. Consistent with this long-standing regulatory practice, the Commission has approved the inclusion of PTYP in rate base for Arizona utilities as a standard ratemaking principle since the 1990s. Accordingly, including projected plant in the Company's proposed FRAM reflects established Commission precedent and helps ensure that the FRAM more accurately matches rates with the cost of providing service.

Q. GIVEN THE IMPORTANCE OF PTYP, HAS APS CONSIDERED CHANGES TO ITS PROPOSAL FOR INCLUDING PTYP WITHIN ANNUAL RESETS OF THE FRAM?

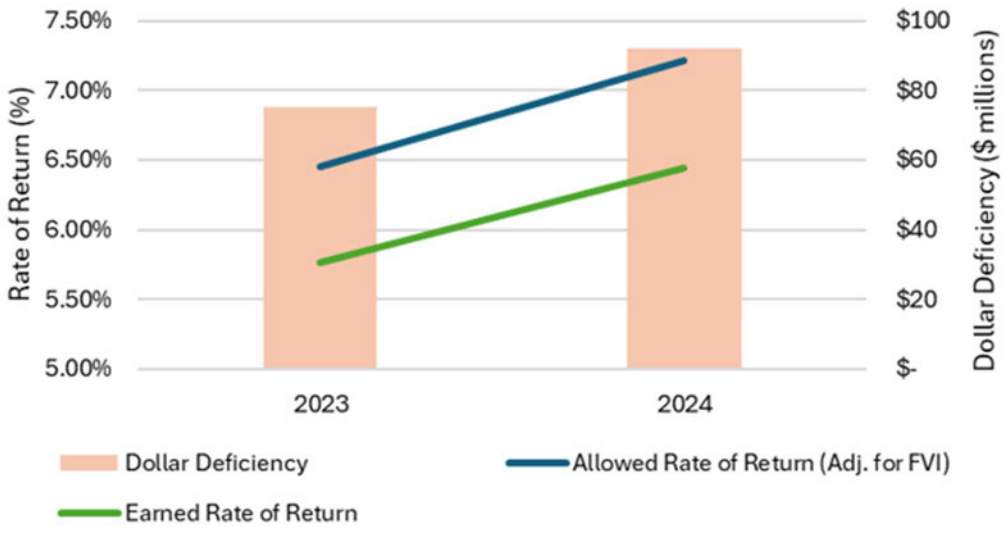
A. Yes. As described in more detail by Ms. Hobbick, APS is proposing changes to the way plant additions after the FRAM historical test year are included within annual FRAM resets in a way that aligns with the positions offered by Mr. Smith in his Rate Design Direct Testimony and the Commission's historical treatment of PTYP. Specifically, APS is now proposing to include only six months of PTYP based on actual, verified costs for new plant in service within that timeframe after the test year for a given FRAM reset, rather than 12-months of project plant. This proposal creates greater alignment with Staff and the Commission's historical approach to including PTYP within Arizona utility company rates, while still meaningfully reducing regulatory lag.

Q. DO EXISTING ADJUSTORS ELIMINATE REGULATORY LAG, MAKING THE FRAM UNNECESSARY?

A. No. While the existing adjustors mitigate regulatory lag to a limited extent, they are narrow in scope and do not address the broad categories of capital investment and cost growth that drive regulatory lag under a historical test year. As a result, APS continues to experience lag even with the current mechanisms.

Figure 4 below is an illustrative example demonstrating that regulatory lag is still present, even with the Company's current adjustors. The figure displays APS's earnings test results for the past two years. Even with the benefit of weather-driven load impacts of $73 million in 2023 and $147 million in 2024, the Company's earned rate of return (WACC) consistently fell short of the allowed rate of return, underscoring that regulatory lag continues to impact the Company's ability to fully recover its costs.

Figure 4. 2023 and 2024 APS Earnings Test Results



Q. EVEN WITH THE FRAM, WHY ARE OTHER ADJUSTOR MECHANISMS STILL IMPORTANT?

A. APS's current adjustor mechanisms and a FRAM serve different but complementary purposes within the regulatory framework. The FRAM is designed to update rates annually based on the Company's overall revenue requirement and financial performance. In contrast, the other annual adjustor mechanisms are designed to address specific, often volatile cost components on a timelier basis and contain features beneficial to customers.

- The Power Supply Adjustor (PSA) only recovers prudently incurred costs related to fuel and purchased power;
- The System Reliability Benefit (SRB) allows for recovery for only those specific generation capital projects procured through APS's All-Source Request for Proposal (ASRFP) process over a set dollar threshold ($50 million minimum);
- The Transmission Cost Adjustor (TCA) allows for recovery specific to transmission capital and operating costs based on the authorized Federal Energy Regulatory Commission (FERC) Formula Rate, a mechanism that has been proven to balance both the customer and company interests and utilized as the model in the Commission's Formula Rate Policy Statement; and
- Other current APS adjustor mechanisms the Company is proposing to retain that have very specific regulatory policy oriented rationales (*i.e.,* the Demand Side Management Adjustment Charge (DSMAC) collects energy efficiency and demand response program expenses, the Renewable Energy Adjustment Charge (REAC) collects historically incurred expenses to meet the state's Renewable Portfolio Standard; and the Tax Expense Adjustment

Mechanism (TEAM) adjusts rates to reflect changes in federal income tax policy).

From a financial perspective, the combination of the FRAM and the current annual adjustors provides a more balanced and stable framework in alignment with the Company's peers, which ultimately supports recovery of fixed and capital-related costs, addresses variable and volatile costs in a timely manner while minimizing rate impacts for customers and reduces overall lag. Additionally, credit rating agencies view timely cost recovery mechanisms as supportive of a utility's financial profile.

Q. IS APS PROPOSING ANY CHANGES TO THE NUMBER OF CURRENT ADJUSTOR MECHANISMS THE COMPANY WOULD MAINTAIN ALONG WITH THE FRAM?

A. Yes. Notwithstanding the importance of parallel adjustor mechanisms that complement the FRAM, APS is mindful of the perspectives offered by Mr. Smith as to those adjustor mechanisms that are necessary to maintain if the FRAM is adopted. APS appreciates and agrees with Staff's perspectives as to the importance of APS's PSA and TCA mechanisms, in particular. APS now proposes that, if the FRAM is adopted by the Commission in this proceeding, the TEAM and SRB mechanisms can be eliminated, in addition to the Lost Fixed Cost Recovery (LFCR) mechanism, consistent with Staff's recommendations in this proceeding. This means that, in addition to the FRAM, APS would only maintain the TCA, PSA, REAC, and DSMAC. This proposal strikes the right balance between the importance of minimizing adjustment mechanisms, which is recognized in the Commission's Formula Rate Policy Statement, and ensuring appropriate

mechanisms remain in place that reduce regulatory lag and ensure financial stability.

Q. IN SUMMARY, WHY IS THE FRAM REASONABLE AND IN THE PUBLIC INTEREST?

A. The FRAM balances regulatory and stakeholder oversight with improved timeliness of cost recovery. It does not guarantee earnings, does not remove prudence review, and provides transparent annual review processes and customer protection features. By reducing structural regulatory lag and enhancing transparency, the FRAM supports APS's ability to attract capital on reasonable terms while providing gradual, more predictable rate adjustments for customers.

V. <u>POWER SUPPLY ADJUSTOR</u>

Q. HOW DOES THE PSA HELP ENSURE FINANCIAL STABILITY?

A. The PSA provides benefits to both customers and the Company as I highlighted in my Direct Testimony. It is a fundamental tool that protects customers and APS by passing through only prudently incurred costs without a markup, provides certainty of recovery and protects liquidity, and is positively viewed by the credit rating agencies. These benefits support the financial stability and credit quality of the Company, leading to lower borrowing costs for customers. Mr. Coyne also noted in his Direct Testimony that all companies within the proxy group used in his analysis have fuel and purchased power adjustment mechanisms.

Q. WHY WOULD APPROVING A 90/10 SHARING MECHANISM HARM THE COMPANY'S FINANCIAL STABILITY?

A. While the 90/10 cost sharing mechanism was briefly part of the Company's PSA in the past, it was removed in 2012 because the Commission determined that it failed to provide benefits to customers. Additionally, after intervenors in APS's last rate case suggested that the 90/10 mechanism be resurrected, this Commission

declined to reinstate it. Since these decisions were made, nothing has changed and a 90/10 split remains a bad solution in search of a problem.

Fundamentally, the 90/10 sharing mechanism effectively disallows the Company from recovering prudently incurred costs of fuel and purchased power used to serve customers and would harm the Company's financial integrity and ability to secure capital at a reasonable cost. As currently designed, the PSA mechanism appropriately balances customer and APS interests. Specifically, in the last fuel and purchased power audit completed as part of APS's 2022 rate case, Staff concluded that the PSA was working as intended and should be retained in its current form.[2]

Contrary to the position of Mr. Madsen, it has been shown that this sharing mechanism does not enable the Company to control pricing or necessarily seek out cost savings for the fuel and purchased power that APS must procure to serve customers. As discussed in more detail by Mr. Smith and APS witness Kent C. Walter, the prices of fuel and purchased power are set by the market and are largely outside of the Company's control. Furthermore, APS does not earn any profit on fuel and purchased power costs through the PSA, but full recovery of such costs is substantial and material to the Company's financial health. For these reasons, the 90/10 sharing mechanism is misguided and not in customers' or the Company's best interests.

[2] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Prop. for Ratemaking Purposes*, Docket No. E-01345A-22-0144, Decision No. 79293 (Mar. 5, 2024) at 191 (citing APS Br. at 41; Ex. S-21 at 17; Tr. at 5019; Ex. S-35 at 7, 12).

Q. HOW WOULD A 90/10 SHARING MECHANISM FOR THE PSA HARM APS'S FINANCIAL STABILITY?

A. Because the 90/10 sharing mechanism significantly increases the risk that 10% of APS's fuel and purchased power costs would be disallowed, this mechanism could threaten APS's financial stability by significantly limiting the Company's liquidity and cash flow. APS incurred an average of roughly $1.8 billion in fuel and purchased power necessary to serve customers from 2023 to 2025—costs set by the market that APS cannot directly control. A 10% disallowance of prudently incurred costs on this scale, which are necessary to serve customers, would be viewed negatively by the rating agencies. Currently, credit rating agencies view this mechanism and its current structure as credit supportive because it supports the reduction of commodity risk, regulatory lag, and earnings volatility, all of which improve the predictability of cash flows.

VI. FAIR AND REASONABLE ROE

Q. IS A 0.90% FVI REASONABLE IN THIS CASE?

A. Yes. In my view, a 0.90% return on the FVI is reasonable. APS originally requested a 1.0% FVI return, but APS is willing to accept Staff witness David C. Parcell's analysis supporting a 0.93% return on the FVI. In that context, a 0.90% return on the FVI is a measured and supportable outcome that remains aligned with both the Company and Staff's analysis.

Q. WHY DO YOU BELIEVE 0.90% IS STILL APPROPRIATE?

A. It is appropriate because it aligns close to Staff's 0.93% result as well as the Company's original request of 1.0% and therefore reflects a reasonable application of the FVI in this case. A FVI return of 0.90% remains well within the range supported by Staff's analysis while also recognizing the role of Fair Value in establishing a reasonable overall return. In my view, that makes 0.90% a balanced and well-supported result in this proceeding.

Q. STATE OF ARIZONA WITNESS MARK E. ELLIS RECOMMENDS THAT THE COMMISSION CONSIDER ADOPTING COMPETITIVE DIRECT EQUITY OR SIMILAR MARKET-BASED APPROACHES TO UTILITY EQUITY FINANCING.[3] DO YOU AGREE?

A. No. Competitive direct equity is a proposed investment model that seeks to replace state regulated returns, determined by the Commission, with market driven bidding for utility equity. We are not aware of any states that utilize this methodology. Such a theoretical pathway to issue equity does not mean APS can raise equity competitively or on terms that are reasonable for customers. This framework would eliminate the Commission's authority to set a fair and reasonable ROE. Instead, that responsibility would be set by private equity firms and other institutional investors and would be subject to market tone, demand, and volatility every time APS seeks to raise equity capital. This untested approach would likely cause wide swings in the cost of equity and could result in extremely volatile customer bills depending on market conditions. New classes of equity investors would be created, introducing unnecessary complexity on issues ranging from accounting to governance. Additionally, all of the existing equity capital invested in APS would remain and require a traditional cost recovery mechanism, creating regulatory complexity.

Through Pinnacle West, APS already raises equity capital in a robust and liquid market for publicly traded utility equity. The Commission already exercises considerable oversight as to equity infusions into APS. Resorting to a secondary market for private equity would be a step backward.

[3] State of Arizona, Direct Testimony of Mark E. Ellis (Mar. 2, 2026) at 98.

Mr. Coyne has utilized multiple time-tested and widely accepted equity pricing models to calculate the market's expected ROE for the Company using current market conditions and then compared those model outputs to a specific set of APS's peers. This market-tested approach ensures that APS can compete for capital with a fair, reasonable, and market competitive ROE. This process is the most accurate and consistently applied methodology to determine the cost of equity for regulated utilities.

Q. COULD APS MAINTAIN ITS CURRENT CREDIT RATING AND CAPITAL ACCESS UNDER MR. ELLIS' RECOMMENDED 6.10% ROE?

A. No. The proposed ROE by Mr. Ellis represents a 36% decrease in the Company's allowed return and would be the lowest allowed return for any investor-owned electric utility in North America, and 35% below the national average.

A 6.10% ROE is not a fair or supportable return for APS, nor is it consistent with the fundamental difference in risk between debt and equity investors. It materially understates the return needed to maintain investor confidence and support APS's ability to raise equity capital on reasonable terms. Mr. Ellis' recommended ROE is closer to APS's current cost of debt than ROEs authorized for the Company's peer utilities in the proxy group. Debt investors have a contractual claim on interest and principal payments. Equity investors, by contrast, assume greater risk because their returns depend on the company's financial performance, do not have a contractual claim to fixed payments, and are required to absorb financial volatility in earnings experienced by the Company. Because equity carries greater risk, investors generally require a meaningfully higher return than the return required by debt investors. With an ROE as low as 6.10%, investors would seek to allocate their capital to utilities that offer more appropriate risk-adjusted returns.

Furthermore, rating agencies consider access to capital markets an important component of a utility's financial risk profile. By limiting APS's ROE to a level far below that of its peers, the Company would face serious and obvious constraints on its ability to access capital markets in a competitive manner. Such constraints would prompt credit rating agencies to re-evaluate APS's current investment-grade credit ratings, given the absence of any meaningful ability for the Company to attract equity capital.

A dramatic reduction to ROE, compared to the company's current allowed ROE, would immediately and significantly reduce operating cash flow to the Company. Lower operating cash flow, relative to the existing debt held by APS would cause significant downward pressure on already weakened key credit metrics that supports the Company's current credit ratings.

Q. WHY IS "STILL INVESTMENT GRADE" NOT ENOUGH?

A. The objective is not simply to avoid falling below investment grade. The objective is to preserve durable access to capital on favorable terms while APS finances a very large and growing capital program. APS must maintain strong credit quality, financing flexibility, and investor confidence across a variety of economic conditions. A punitive ROE would weaken APS's attractiveness to investors and substantially increase financing risk.

Q. DID APS EVALUATE THE EFFECT THAT MR. ELLIS' PROPOSED 6.10% ROE COULD HAVE ON APS'S CREDIT PROFILE?

A. Yes. As a high-level illustration, the Company evaluated the effect of reducing APS's 2025 cash flow by approximately $400 million, which is roughly the revenue requirement decrease associated with reducing APS's allowed ROE from the Company's current 9.55% to 6.10%. Figure 5 below shows that APS's cashflow from operating activities (CFO) pre-working capital to debt metric would decline

from approximately 18.4% based on 2025 actuals to approximately 14.0% if that $400 million were removed from cash flow on its own. That level of operating cash flow degradation, combined with the likelihood of falling below the "junk bond" threshold of 13.0% in subsequent years, would likely result in the Company being downgraded at least twice from Baa1 to Baa3 in the near term and then potentially further to sub-investment grade in the coming years as infrastructure financing needs continue. That would do irreparable harm for decades, with financing activities and interest expense requiring a much higher rate that is passed on to customers.

Figure 5. Impact of $400 Million Reduction to Cash Flows on CFO

	2025 APS	2025 APS less $400M
CFO Pre-WC	$1,646	
CFO Pre-WC (less $400M CFO)		$1,246
Total Debt	$8,925	$8,925
CFO Pre-WC to Debt	**18.4%**	**14.0%**

Q. WHAT CONCLUSION DO YOU DRAW FROM THAT ANALYSIS?

A. My conclusion is that Mr. Ellis' 6.10% ROE proposal would materially impair APS's financial profile and access to capital for a very long period of time. APS competes with similarly situated utilities for debt and equity capital, and investors compare APS's returns, credit profile, and regulatory support to those comparable utilities when deciding where to invest capital. An outcome that reduces APS's cash-flow metric from 18.4% to potentially 14.0% would raise APS's risk profile materially above similarly situated peers and at the same time reduce the return profile of the Company, quite literally making APS completely unattractive to investment.

Q. DOES APS HAVE ACTUAL EXPERIENCE DEMONSTRATING THAT AN UNCOMPETITIVE AUTHORIZED RETURN CAN AFFECT CREDIT PERCEPTIONS?

A. Yes. Following the Commission's rate decision arising from the 2019 general rate case filing,[4] the final authorized 8.7% ROE was immediately followed by immediate credit pressure, including two credit downgrades and negative outlook actions by all rating agencies. That history demonstrates that the relationship between authorized returns, regulatory support, and credit quality has real and immediate impacts on APS. APS's experience also shows that once a downgrade occurs, recovering from it is extremely difficult and can take a very long time. Even after what was viewed as a more constructive outcome in the Company's 2022 rate case, APS still received an additional downgrade from Moody's. That illustrates an important practical reality: downgrades can occur quickly but upgrades generally require a much longer period of sustained financial and regulatory improvement. As a result, a downgrade can lock in a weaker credit profile and higher capital costs for an extended period, with those costs ultimately borne by current and future customers.

The consequences of uncompetitive authorized returns are particularly important when considering the factors credit rating agencies evaluate when assessing utility credit quality. Moody's, among other things, examines the Company's ability to recover costs and earn returns as well as its financial strength and key credit metrics. A punitive ROE would weaken those considerations, not strengthen them. Additionally, because APS's capital needs are substantially greater today than they were in the earlier cases (as described in my Direct Testimony), any downgrade

[4] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Prop. for Ratemaking Purposes*, Docket No. E-01345A-19-0236, Decision No. 78317 (Nov. 9, 2021).

pressure resulting from a punitive ROE in this proceeding could increase customer costs and impair financial flexibility for many years to come.

Q. MR. ELLIS ARGUES THAT HIGHER ROES INCENTIVIZE UTILITIES TO ARTIFICIALLY INFLATE RATE BASE. DO YOU AGREE WITH THAT CHARACTERIZATION AS APPLIED TO APS?

A. No. APS's capital plan is driven by actual system needs, including load growth, infrastructure modernization and hardening, reliability requirements, extreme summer heat and other climate pressures, asset aging, and other factors that have nothing to do with APS's specific ROE. Collectively, these are operational realities and necessities aimed at ensuring safe and reliable service. Please refer to the Direct and Rebuttal Testimonies offered by APS witnesses Jacob Tetlow and Michael Eugenis for a description of how load growth and system needs drive APS's capital spending—not ratemaking outcomes.

Q. WOULD THE ROE RECOMMENDATION OF ARIZONA LARGE CUSTOMER GROUP (AZLCG) AND FREEPORT MINERALS CORPORATION (FREEPORT) WITNESS DAVID J. GARRETT LEAD TO SIMILAR OUTCOMES?

A. Yes. While the ROE recommendation of Mr. Garrett is not as extreme as Mr. Ellis recommendation, Mr. Garett's ROE combined with his equity ratio recommendation would still be exceptionally punitive relative to APS's investment risk and its proxy group. With the Company's actual capital structure, Mr. Garrett's ROE recommendation for APS would drop further to 7.9%.

Q. AS COMPARED TO MR. ELLIS, HOW WOULD MR. GARRETT'S 7.9% ROE RECOMMENDATION AFFECT THE COMPANY'S ABILITY TO ACCESS CAPITAL ON REASONABLE TERMS AND MAINTAIN A STABLE INVESTMENT GRADE CREDIT RATING?

A. Again, while the two recommendations are numerically different, they both share the same characteristics of dramatically understating APS's investment risk relative to its peers and, therefore, both represent a punitive ROE. For the same reasons as Mr. Ellis' 6.1% recommendation, Mr. Garrett's 7.9% recommendation would completely undermine APS's ability to access equity capital and would almost certainly result in APS losing its current credit ratings.

VII. CAPITAL STRUCTURE

Q. MULTIPLE PARTIES CRITICIZE THAT APS'S PROPOSED CAPITAL STRUCTURE IS TOO EQUITY RICH BECAUSE IT IS ABOVE THE PROXY GROUP. SHOULD THE COMMISSION REJECT APS'S PROPOSED CAPITAL STRUCTURE ON THAT BASIS?

A. No. Both Mr. Parcell and RUCO witness Dr. Zhen Zhu, recommend accepting APS's actual Test Year capital structure in their testimonies. Mr. Garrett, however, proposes a hypothetical structure that does not put any emphasis on APS's actual financing requirements, risk profile, and need for reliable access to capital. This capital structure represents APS's actual Test Year capital structure, the actual level of the Company's equity layer used to support its current credit ratings, and source and secure necessary investment capital funding for safe, reliable operations during the Test Year. This capital structure, therefore, reflects a market-determined equity layer providing APS reasonable access to capital on competitive terms for customers and stable investment grade credit ratings.

Q. WHY IS IT SIGNIFICANT THAT APS IS PROPOSING TO USE ITS ACTUAL TEST YEAR CAPITAL STRUCTURE IN THIS CASE?

A. It is significant because APS's actual Test Year capital structure reflects the capitalization APS maintained during the Test Year, the same period the Commission uses in this proceeding to assess rates and revenue requirement. This makes it the most reliable and relevant measure of the capital structure needed to support APS's operations, access to capital on reasonable terms, and maintain the Company's current credit ratings under current market conditions. It is not a hypothetical or optimized ratemaking construct. It is the real capital structure under which APS operated in the Test Year, and under which investors and creditors were willing to provide capital. The actual Test Year capital structure is, therefore, a more reliable basis for ratemaking.

Q. DOES THE RECORD SUPPORT THE REASONABLENESS OF APS'S PROPOSED CAPITAL STRUCTURE?

A. Yes. Mr. Parcell uses APS's proposed capital structure in his recommendation, and Dr. Zhu and Mr. Parcell would also accept APS's actual capital structure. As between APS and RUCO, the difference of views is not whether APS's actual Test Year capital structure is outside a reasonable range, but whether that capital structure and the approval of a formula rate (APS's proposed FRAM) should present a basis to push APS's authorized ROE arbitrarily lower.

Q. WHY IS THE PROPOSED EQUITY COMPONENT APPROPRIATE FOR APS?

A. It is appropriate because APS is facing significant and growing capital needs and must preserve financial stability while competing for debt and equity capital. As described in my Direct Testimony, a sound equity component is credit supportive, balances financing risk, and helps ensure that APS can continue to access capital on reasonable terms while funding infrastructure needed to serve customers safely

and reliably. That testimony described how higher percentages of equity that are authorized to fund business investment typically translate into higher credit quality and lower borrowing costs. APS's Test Year equity layer, as requested in this case, enables it to maintain current credit ratings, financial strength, and flexibility. The magnitude of APS's capital requirements dictates the need for a sufficient equity component of the Company's capital structure to support strong credit ratings and ensure access to capital at reasonable returns.

Q. DOES MR. PARCELL RECOMMEND THAT THE COMMISSION REJECT APS'S PROPOSED CAPITAL STRUCTURE?

A. No. To the contrary, Mr. Parcell's recommended cost of capital uses APS's proposed 52.35% common equity ratio and 47.65% debt ratio. That is significant because it demonstrates alignment with the perspectives of Staff.

Q. DR. ZHU CRITICIZES APS'S EQUITY RATIO AS HIGHER THAN THE INDUSTRY NORM. DOES DR. ZHU RECOMMEND THAT THE COMMISSION REJECT APS'S PROPOSED CAPITAL STRUCTURE?

A. No. Dr. Zhu expressly recommends that the Commission accept APS's actual capital structure. His recommendation is instead to reduce the authorized ROE by 20 basis points based on his view of the FRAM and APS's equity ratio. Dr. Zhu's testimony, however, is not evidence that APS's capital structure itself is outside the range of reasonableness. To be clear, APS's actual Test Year capital structure is reasonable for ratemaking purposes. As discussed in my Direct Testimony, as of June 2025 APS's actual capital structure and, more specifically, APS's equity ratio, is well within the range of the proxy group discussed in Mr. Coyne's Direct Testimony. The proxy group equity ratio is over 52%, with the upper band of the proxy group range having a nearly 60% equity ratio. In fact, APS's Test Year equity ratio is actually below the approved equity layers in three utility rate cases

approved in Arizona in 2024 as reflected in my Direct Testimony. For this reason, Dr. Zhu's 20 basis points ROE reduction is arbitrary and unsupported.

Q. DO YOU AGREE WITH DR. ZHU'S ASSESSMENT OF THE CAPITAL STRUCTURE AND REDUCTION TO ROE?

A. No. APS's actual Test Year capital structure and the existence of the FRAM would not change APS's risk profile and need for investor support and access to capital. APS continues to face substantial capital requirements, regulatory lag, and meaningful business and financial risks. As described earlier in this testimony, a capital structure with a strong, competitive equity layer is credit supportive and helps APS navigate volatile financial market conditions by providing stronger balance sheet support and greater financing flexibility. It should not be misconstrued as evidence that APS no longer requires a fair ROE or that the Company has become lower risk.

Q. DO YOU AGREE THAT A MORE CREDIT SUPPORTIVE CAPITAL STRUCTURE MEANS APS IS LESS RISKY THAN ITS PEERS?

A. No. In my view, "credit supportive" and "less risk" are not the same. A capital structure can be designed to support credit quality and financing stability in the face of business, regulatory, and capital access risks. That does not mean those risks disappear (which is described earlier in this testimony). It also does not mean APS's underlying risk profile is lower; it only means that APS's actual Test Year capital structure is supportive of credit quality and capital access given the risks the Company continues to face. A credit supportive capital structure helps APS maintain financial stability and access to capital despite those risks; it does not change the existence of risks.

Q. DOES THE COMPANY'S PROXY GROUP EVIDENCE SUPPORT THE REASONABLENESS OF APS'S PROPOSED CAPITAL STRUCTURE?

A. Yes. Mr. Coyne evaluated APS's proposed capital structure against the capital structures of the proxy group operating utilities and concluded that APS's proposed 52.35% common equity ratio is consistent with those companies. In fact, he found that APS's proposed equity ratio is slightly lower than the mean and median common equity ratios for the proxy operating companies. That confirms that APS is not over-equitized when the comparison is made on the proper basis.

Q. WOULD MR. GARRETT'S HYPOTHETICAL CAPITAL STRUCTURE BE CREDIT SUPPORTIVE FOR APS?

A. No. A materially more leveraged capital structure is not credit supportive unless APS also has the cash flow, earnings support, and regulatory recovery profile necessary to service that amount of additional debt while preserving strong credit quality. On its own, more debt does not strengthen credit. It increases fixed financial obligations and, therefore, requires stronger, more predictable alignment of cash flows. Forcing APS into materially greater leverage while the Company is facing substantial investment needs would not be credit supportive and would increase APS's underlying risk.

VIII. OTHER FINANCIAL MATTERS

Q. AZLCG, FREEPORT, AND RUCO WITNESS COURTNEY M. HIGGINS RECOMMENDS THAT APS CREDIT CUSTOMER RATES FOR NUCLEAR PRODUCTION TAX CREDITS (PTC) "AS SOON AS THE AMOUNT IS KNOWN WITH REASONABLE CONFIDENCE." DO YOU AGREE WITH THIS RECOMMENDATION?

A. Yes. APS agrees in principle with Ms. Higgins and believes that "reasonable confidence" should be interpreted in a manner that is consistent with established

accounting and tax recognition standards, while also recognizing the Commission's role in determining the appropriate timing for ratemaking treatment. For federal income tax purposes, Nuclear PTC remain subject to uncertainty, including unresolved guidance from the United States Treasury (Treasury) regarding the definition of "gross receipts" used to determine credit phase-out. Consistent with Generally Accepted Accounting Principles (GAAP), APS ordinarily recognizes tax benefits only when it is more likely than not that the position will be sustained upon examination.

Accordingly, APS believes "reasonable confidence" would ordinarily be achieved upon the earlier of:

- Issuance of Internal Revenue Service (IRS) or Treasury guidance resolving the relevant uncertainty;
- Completion of an IRS examination confirming the Company's calculation; or,
- Expiration of the applicable IRS statute of limitations.

Q. HOW DOES APS INTEND TO CREDIT CUSTOMERS THE BENEFITS OF THE NUCLEAR PTC?

A. APS intends to credit customers with the net benefit actually realized after accounting for incremental costs incurred to secure and sustain eligibility for the enhanced Nuclear PTC that have not, otherwise, been recovered in rates. While Ms. Higgins discusses the gross amount of the Nuclear PTC in the context of potential revenue requirement impacts, her testimony does not discuss the incremental costs incurred to secure the enhanced credit. APS's position is that customers should receive the benefit actually realized after accounting for the incremental O&M costs required to qualify for the enhanced Nuclear PTC, including compliance with prevailing wage requirements.

Q. WHAT DO YOU MEAN BY THE "ENHANCED" NUCLEAR PTC?

A. The "enhanced" Nuclear PTC refers to the additional credit amount available under federal law when applicable prevailing wage requirements are satisfied. For the 2024 credit year, the Nuclear PTC consists of a lower base credit, and a substantially larger incremental amount that becomes available when prevailing wage compliance is achieved.

As reflected in the record, and cited by Ms. Higgins, APS's 2024 Nuclear PTC totaled approximately $33.4 million. Of that amount, approximately $6.7 million represents the base credit that would have been available absent prevailing wage compliance, while the remaining portion—approximately $26.7 million—is attributable to the enhanced credit amount made available as a result of satisfying prevailing wage requirements, which was only possible after APS undertook a comprehensive prevailing wage compliance effort.

Q. HOW DOES APS INTEND TO RETURN NUCLEAR PTC BENEFITS TO CUSTOMERS ONCE THE AMOUNT OF THE BENEFIT IS KNOWN WITH REASONABLE CONFIDENCE?

A. APS would use the FRAM to return Nuclear PTC benefits to customers. The FRAM would allow actual, realized Nuclear PTC benefits to be reflected on an annual basis and provide a transparent, administrable framework for incorporating changes in income tax expense associated with the credit. Importantly, the FRAM is well suited to address not only the return of the Nuclear PTC benefits to customers, but also to address future adjustments if those benefits change.

Q. MS. HIGGINS RECOMMENDS THAT DURING AMORTIZATION OF BATTERY ENERGY STORAGE SYSTEM (BESS) INVESTMENT TAX CREDIT (ITC) BALANCES, RATE BASE SHOULD ALSO BE REDUCED. HOW DOES APS RESPOND?

A. APS agrees that customers should receive the benefits of the BESS ITC. APS does not agree, however, that these ITC benefits should be reflected in rates through multiple, overlapping ratemaking mechanisms for the same credit.

When the United States Congress (Congress) established the ITC, it did so to encourage capital investment while providing for a deliberate and transparent sharing of benefits in the regulated utility context. Legislative history reflects an intent to avoid either extreme—neither permanent retention of the credit by the utility, nor a double-counting of the credit by customers through layered ratemaking treatment. Rather, Congress contemplated a single, balanced mechanism through which the credit would be reflected in rates, through either (i) cost-of-service amortization, or (ii) a reduction to rate base for the unamortized credit.

In 2022, Congress enacted the Inflation Reduction Act (IRA), which expressly permits certain utilities to elect out of full normalization requirements for newly eligible ITCs. That opt-out election affects the timing and manner in which credits may be reflected in rates. However, nothing in the IRA or its legislative history suggests Congress intended to alter the longstanding principle that these credits be shared and reflected through a single ratemaking mechanism, or to permit double-counting of the same credit through concurrent rate base and cost-of service treatment.

APS's proposal is consistent with that framework. Under the IRS full-normalization rules, APS historically reflected the ITC through a rate-base offset restored ratably over the book life of the underlying asset, with amortization occurring below-the-line. Having elected to opt-out of normalization for its BESS ITC, APS now proposes to return the BESS ITC benefit to customers on an accelerated basis through cost-of-service amortization that returns the net economic value of the credit more quickly. It would be inconsistent with federal tax law to apply a concurrent rate-base reduction for the same ITC, as doing so would double-count the benefit of the credit in customer rates, eliminating the balanced sharing of benefits Congress intended.

Q. IS THERE ANY CONCERN THAT THE AMOUNT OF BESS ITC REFLECTED IN RATES ON AN ACCELERATED BASIS COULD BE SUBJECT TO POTENTIAL FUTURE CHANGE BY THE IRS?

A. Yes. As with other federal tax credits, the amount of BESS ITC ultimately sustained may be subject to change as a result of IRS examination or other subsequent review. APS has recently been notified that the IRS intends to examine the Company's 2023 tax return, which includes ITC associated with the Arizona Sun BESS. As with any IRS examination, the outcome of this exam could affect the amount of tax credit ultimately sustained.

In addition, for BESS facilities that have not yet been fully reflected on a filed tax return, such as Agave BESS, the ITC amount reflected in rates is based on current estimates and will not be final until the applicable tax return is filed. That amount may also be subject to further review through examination.

As a result, the amount of BESS ITC ultimately realized by the Company could differ from the amount initially reflected in customer rates.

Q. HOW DOES APS PROPOSE TO ADDRESS THAT RISK?

A. Consistent with the approach described above for the Nuclear PTC, the FRAM, which would be used to return BESS ITC benefits to customers, should also provide for reciprocal recovery in the event the credit amount is subsequently adjusted.

If the IRS were to determine that some or all of the BESS ITC previously reflected in rates was overstated, APS would be required to repay the disallowed portion of the credit to the IRS. Under federal tax law, such repayment would include not only the principal amount of the credit disallowed, but also statutory interest and any other amounts assessed by the IRS as a result of that determination.

APS proposes that these income tax impacts, including the loss of the ITC benefit and any associated interest or other IRS-assessed amounts, if any, be included in customer rates using the FRAM. This approach ensures that customer rates ultimately reflect the actual BESS ITC benefits realized by APS, preserves symmetry, and avoids unintended cost shifts.

Q. HAS APS REVISED ITS ESTIMATE OF THE AGAVE BESS ITC BENEFIT?

A. Yes. APS has revised its estimate of the Agave BESS ITC benefit that it intends to claim on its 2025 tax return, and those updated estimates are reflected in APS's Post-Test-Year plant pro-forma adjustments filed with Rebuttal Testimony.

IX. FINANCIAL TERMS IN APS'S LOAD COMMITMENT AGREEMENT (LCA) NECESSARY TO PROTECT CUSTOMERS

Q. PLEASE DESCRIBE THE OVERALL FINANCIAL OBJECTIVES OF LCAS.

A. LCAs are designed to balance four related, though competing, financial objectives:

(1) Prevent Cost-Shift: APS operates a system in which one customer's non-payment burdens another customer who continues to pay. In a distributed customer base in which no single customer represented a significant proportion of the total system, these burdens were small and could be shared over time. Historically, APS's largest commercial customer was a mining operation of approximately 75 MW. Today, however, APS is serving and planning to serve multiple large, high load factor customers requiring hundreds, if not thousands, of MWs of generation capacity at each site. In the absence of contractual mechanisms to manage this risk, existing customers would now be exposed to funding the infrastructure investments, power procurements, and other costs incurred for these new large, high load factor customers. This fundamental change in risk dynamics has made the avoidance of cost-shifts a primary issue that the Company seeks to address in the LCAs with provisions such as 15-year terms, minimum bills, notice provisions, termination payments, and financial security ("collateral").

(2) Support Long-Term Investment: Because these large potential customers are adding significant load to the system, APS is investing billions of dollars in new generation, transmission, and distribution assets to serve them. Infrastructure finance is capital intensive and relies upon securing long-term agreements to mobilize this investment. This is why the Power Purchase Agreements (PPAs) are twenty-years and contain provisions similar to what APS requires in the LCAs.

(3) Secure Contract Performance: Due to the size of required investment and the risk of customer cost-shift, signing a contract by itself is not enough to ensure that a large load customer performs their obligations and pays their bills. Therefore, the Company requires termination payments that match their contractual obligations. This is because long-term investments are enabled by the customer's entire contract obligation, not just their month-to-month billing. APS similarly requires collateral, which protects other customers from cost-shifts while disincentivizing the counterparty from forcing us to rely on the courts to enforce their contractual obligations. In efforts to reduce the risk to the participating customer, APS has also included "suitable offtaker" language where APS can reassign or repurpose the capacity allocation to another customer who is willing and able to sign a similar contract, which relieves the original customer's obligation.

(4) Achieve Commercial Acceptance: In addition, the Company seeks to support the communities it serves by enabling long-term investment by APS and large load customers, while protecting the interests of other customers. By balancing those objectives, and assuming an informed and appropriate amount of commercial risk, the Company has been able to execute multiple LCAs with large load customers.

Q. HOW DO LCAS PROMOTE "GROWTH PAYS FOR GROWTH"?

A. As I stated earlier in my testimony, customers in APS's system share the benefits of growth and the burdens of the loss of load in APS's service territory. The amount of electric service required by large load customers requires a significant amount of investment to meet their needs. While this incremental investment provides general benefits to the system, the concentration of large loads also increases risks to the system. Credit, business profile, and macroeconomic cycles are risks APS has always faced within the system. Today, however, given the present influx of

large, high load factor customers, those risks are more pronounced and more concentrated to a smaller number of parties than ever before. As such, the LCA has become a necessary tool to strike the right balance between large load customer acceptance, maintaining APS's financial stability, and protecting existing APS customers from cost shifts.

Q. IS IT FAIR TO INTRODUCE THE REQUIREMENTS FOR EXECUTING A LCA FROM COUNTERPARTIES AFTER APS HAS COMMITTED TO SERVING THEIR LOAD?

A. Yes, and APS should maintain its focus on the financial objectives of risk reduction and the prevention of customer cost-shift. Phoenix Hydrogen Hub, LLC (PHH) witness Su Lin Ong is wrong that APS can protect existing customers by simply assuming that suitable replacement counterparties exist and that those counterparties are willing to assume the risk of covering the costs of necessary infrastructure intended to serve a defaulting or defunct customer. APS's current "uncommitted" queue of large, high load factor customers is simply a list of parties who have expressed interest in taking service. It does not entail that these interested parties have the willingness or financial wherewithal to ensure cost recovery for the investments and expenses that would be necessary to serve them. Further, due to the low barriers for entry, many of these projects have positions in similar utility queues. These queues exist not only across the other utilities within Arizona, but across the country. The transient nature of the hyperscaler projects leads to uncertainty around how much of the existing queue will materialize when capacity does become available.

Imagine a potential scenario during which APS loses one (or multiple) large load customers and the demand for large load growth has stalled such that APS does not have a readily available replacement offtaker for the loss of a large load customer.

The Company is confronting this risk head-on today and the LCA provides a responsible means of balancing the objectives of growth, investment, obligation to serve, and the imperative to protect customers from cost-shifts. By contrast, operating under the assumptions PHH is advocating would place the burden of bearing costs incurred from abandoned large load projects on other customers.

Q. HOW DOES THE REQUIRED FINANCIAL SECURITY IN AN LCA CHANGE OVER TIME?

A. It evolves in several ways that reflect the underlying risk that APS and its customers face when extending service to large, high load factor customers. The basic financial security (or "collateral") framework is based on the proposed extra high load factor (XHLF) tariff rate, grown at an assumed rate of inflation, multiplied by minimum demand and minimum energy, less estimated potential wholesale market revenues (together a "revenue deficiency") and multiplied by an estimate of the years of coverage, which is then financially discounted at 7% annually over the term. The most important driver of the change in collateral amount is the estimate for years of coverage (*i.e.,* the period of time over which the collateral covers risk of default), which ranges from two to five years, depending on the year and the size of the customer. In short, the estimated coverage is lower in the near-term (two to three years), higher in the medium-term (four to five years), and then is reduced (one to two years) at the end of the contract, which reflects the different levels of risk APS and its customers confront over the term of the LCA. Using this structure for the financial security in the LCA, APS has successfully negotiated multiple LCAs with large, high load factor customers.

Q. IS IT FAIR TO INCREASE FINANCIAL SECURITY REQUIREMENTS BY ESCALATING THE XHLF TARIFF RATE TO REFLECT MULTIPLE YEARS OF PROTECTION?

A. Yes. Applying an escalation factor to the XHLF tariff rate at the rate of general economic inflation simply acknowledges that costs of service, which are influenced by numerous factors out of the Company's control, tend to rise over time. Without such an assumption for the purposes of calculating collateral over the 15-year period of the contract, APS would be favoring prospective large load customers at the expense of future retail ratepayers.

Q. PLEASE EXPLAIN THE APPROACH TO THE FORMS OF COLLATERAL ACCEPTED BY APS.

A. APS primarily accepts collateral in the form of cash, surety bonds, or irrevocable letters of credit, and the counterparties from which the Company accepts surety bonds and letters of credit must be United States-based financial institutions. APS may accept a parent guarantee for a portion of the required collateral. The parent guarantee framework is evolving but generally requires: (a) the guarantor credit rating that is considered is either (i) the counterparty signing the LCA, or (ii) the tenant for such a counterparty (*e.g.,* a data center tenant), provided that APS has legal recourse to the highly-rated tenant; (b) the guarantor credit rating is no lower than A- / A3 as measured by Nationally Recognized Statistical Rating Organizations (*e.g,.* Standard & Poor's or Moody's); (c) the guarantor is based in the United States; and (d) the amount of guarantee accepted is less than 100% of the required collateral.

Q. PLEASE DESCRIBE THE TERMINATION PROVISIONS IN THE LCA.

A. The termination provisions in the LCAs are calculated by taking the sum of the minimum bill payments through the remaining term of the contract. The LCA also includes important mitigation provisions that allow a terminated LCA to be

assumed by a "suitable offtaker," which reduces the terminating customers ultimate liability. This construct mirrors the PPAs that APS signs with third-party power generators, except that those contracts are "take or pay" for 100% of the capacity or energy provided. This termination fee structure is intended to provide financial protection for APS's broader customer base who are exposed to the risk of paying the costs that would have otherwise been recovered in a terminating customer's LCA. Coupled with the mitigation provisions, these terms are reasonable and consistent with comparable terms imposed by APS's peer utilities.

Q. WHY IS A 15-YEAR TERM APPROPRIATE FOR THE LCA?

A. A 15-year term appropriately balances protections for existing customers and commercial acceptability. In the absence of an LCA customer deciding to renew their agreement, which is a determination that must be made no less than 36 months prior to the end of the LCA term, the 15-year term is automatically renewed by the customer for continued service under the same terms. Alternatively, if the customer elects to cease taking service at that time, APS can use the generation and other infrastructure, which was originally procured to serve the LCA customer, as a way to defer or avoid future investments or procurements. These assets can also be used to serve a replacement customer seeking similar service at that point in the future.

It is important to recognize that the LCA customer renewal determination presents APS with significantly different circumstances than a customer that provides notice terminating the LCA. When a customer elects not to renew the LCA, APS has 36 months to assess how the generation and other infrastructure procured for the original LCA customer can be repurposed, for either a replacement customer or APS's wider system needs (*e.g.,* in the case of investment deferral). The 36 month period is a reasonable period of time to ensure that all other APS customers are held harmless through this transition.

Q. DO APS CUSTOMERS RECEIVE A WINDFALL ON TERMINATION PAYMENTS MADE UNDER THE LCA?

A. No. First, one of the primary purposes of the LCA is to protect other customers from cost-shifts. Second, the Company has designed the termination liability such that, if APS can mitigate losses—whether the suitable offtaker is another large, high load factor customer or other APS customer then APS would reduce the defaulting customer's liability by that amount. Collectively, this structure ensures that a terminating customer is not ultimately liable to APS for an amount greater than the total unrecovered payments under the LCA, net of any mitigation based on the identification of a suitable offtaker that can assume the LCA obligations.

Q. IS IT FAIR TO REQUIRE THE TERMINATION PAYMENT WITHIN 30 DAYS IF MITIGATION MEASURES TAKE LONGER TO EFFECTUATE AND, IN THE MEANTIME, APS IS ABLE TO ENGAGE IN OFF-SYSTEM ENERGY SALES USING EXCESS GENERATION CAPACITY?

A. Yes. In this circumstance, there would be a gap in time between customer termination and the identification of a suitable offtaker willing and able to assume any remaining LCA obligations of the terminating customer. In this termination scenario, the customer has stopped paying their bill, presumably either due to financial distress or convenience. By its nature, because it is intended to function as protection for APS's existing customers, the termination payment is significantly larger than the minimum monthly bill payment; therefore, if the customer is unwilling to pay their monthly minimum bill, the Company should have the right to require—even if APS may not reasonably expect—that the customer pay the termination payment over the near term (within 30 days of termination notice).

Q. WHY DOES APS APPLY 5% FOR THE DISCOUNT RATE WHEN CALCULATING TERMINATION LIABILITY INSTEAD OF APS'S WACC?

A. The discount rate is a reduction in the termination payment intended to approximate how this obligation would be treated if it were secured debt. This is because the termination fee essentially accelerates the customer's obligation for paying the LCA minimums (80% energy and 80% demand) immediately upon termination, as opposed to payments over the remaining term. Accepting Ms. Ong's position on the governing discount rate fundamentally reduces the level of protection the termination penalties provide for all other APS customers.

It is important to recognize that customer termination is a downside scenario; the liability is triggered because the customer is either unable, or has elected not, to perform their obligations under the LCA. The termination payment is not intended to be an asset to APS; rather it is meant to: (1) make APS customers whole from the standpoint of the customer's LCA obligations, and no further; and (2) protect other customers from an unfair cost-shift. In this sense, it is better to understand termination not in the context of a revenue-earning asset (which it is not), but instead, in the context of a secured obligation. Therefore, it is more appropriate to view APS's cost of debt as a proxy, and that cost is much closer to 5%. This is the framework by which APS has agreed to discount its own termination liabilities to third-party power generators in PPAs. For this reason, it is reasonable to apply the same framework for the Company's LCAs with large, high-load factor customers.

Q. HOW DO YOU RELATE THE TERMINATION LIABILITY TO THE REQUIRED FINANCIAL SECURITY?

A. It is important to understand that termination and collateral are different concepts. Termination relates to a party's obligations in a contract and represents a penalty

for non-performance of that contract. Collateral is a financial tool that serves to secure a counterparty's performance obligations. In practice, this means that APS has the ability to access a commercial counterparty's posted collateral in the event of a default, rather than wait for a judgment as to termination fee obligations, or be left facing the pursuit of recovery through a counterparty's bankruptcy proceeding.

In developing the financial security (*i.e.,* the collateral) required in LCAs, the Company established a framework to address expected commercial exposure. APS's commercial exposure involves exercising judgement on the ability to respond to the loss of a customer (*e.g.,* through bankruptcy or another form of contract default). Those responses may include seeking to enforce a counterparty's contract obligations, identifying a suitable offtaker, retiring owned assets, or terminating supply contracts. Any of these actions would require APS to expend financial resources, the costs which may be incurred by the Company's wider customer base. By requiring collateral or financial security with LCAs, APS is protecting customers by preventing a cost-shift from large load customers who cannot perform their obligations.

Q. SHOULD APS SET FINANCIAL SECURITY REQUIREMENTS AND THE IDENTIFICATION OF A SUITABLE OFFTAKER BASED ON ITS SOLE DISCRETION?

A. Yes, because it is necessary to maintain critical flexibility. Ms. Ong attempts to represent that APS imposes "sole discretion" terms across the LCA when, in fact, this term arises in only two places: determining a suitable offtaker and allowing for a parent guarantee to function as financial security. As to both, the structure is appropriate and reasonable.

In the case of a suitable offtaker, APS must weigh numerous factors that contribute to a replacement offtaker's suitability, including, but not limited to, the size and type of requested service, the time to which such service is achieved (*i.e,.* load ramp), customer profile, customer credit rating, and other terms of service. The breadth and complexity of these factors require APS to exercise judgement that balances objectives, such as speed to mitigation, sufficiency of mitigation, and the nature of the new customer relationship. Given the importance of avoiding a cost-shift, and the likely scenario of APS being forced to pursue a terminating customer to enforce payment of their termination obligations, APS is clearly motivated to achieve an expeditious and comprehensive mitigation. Therefore, requesting "sole discretion" is not a burden on the terminating counterparty.

Second, in the context of financial security, the nature of a guarantee is such that APS is assuming unsecured credit from the guarantor. As APS serves a greater number of large, high-load factor customers, the size and nature of unsecured credit risk that APS can assume changes over time. For example, if APS accepts a guarantee from two different counterparties in two different LCAs, then APS has diversified this unsecured credit risk. But if APS accepts a guarantee from the same counterparty in two different contracts, that risk is not diversified; in fact, it is exacerbated. In the same way that APS manages its balance sheet to ensure investment-grade credit ratings to serve its customers at a competitive cost of capital, APS must also manage its unsecured credit exposure to ensure that same quality of service.

X. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

REBUTTAL TESTIMONY OF ELIZABETH A. BLANKENSHIP

On Behalf of Arizona Public Service Company

Docket No. E-01345A-25-0105

April 3, 2026

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REBUTTAL TESTIMONY OF ELIZABETH A. BLANKENSHIP
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-25-0105)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Elizabeth A. Blankenship. I am the Vice President, Controller and Chief Accounting Officer for Arizona Public Service Company (APS or Company), a subsidiary of Pinnacle West Capital Corporation (Pinnacle West). I am primarily responsible for overseeing the financial accounting and reporting functions of the Company and Pinnacle West. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes. I filed Direct Testimony on June 13, 2025.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rebuttal Testimony is to address several adjustments to rate base and operating income proposed by the Arizona Corporation Commission (Commission) Utilities Division Staff (Staff), the Residential Utility Consumer Office (RUCO), Arizona Large Customer Group (AZLCG), Federal Executive Agencies (FEA), American Association of Retired Persons (AARP), and other intervenor witnesses. I indicate in my Rebuttal Testimony when the Company agrees with their recommendations and discuss those recommendations that I do not believe are accurate or appropriate. In addition, I will present the Company's updated information for certain pro forma adjustments and provide the associated updated Standard Filing Requirements (SFR) Schedules.

I do not address every detail related to Staff and intervenor recommendations, and it should not be interpreted that I agree with any of their positions unless specifically stated in my testimony.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Staff and intervenors, as well as the Company itself, have proposed both rate base and operating income adjustments to the Company's original request in this rate case. In several instances, the proposed revisions are for reasonable adjustments or seek to make any corrections or adjustments identified during the discovery process. For each instance, I address my goal is to ensure the Test Year (Test Year is the 12-month period ending December 31, 2024) is more representative of the period of time that rates will be in effect. In some cases, the proposals are for reasonable revisions due to updated information that was not available at the time the Company filed its original request. However, other proposed adjustments by the parties are inaccurate or inappropriate, or both, and I discuss why these adjustments should either be revised or not accepted at all. Additionally, some proposed adjustments APS can accept in principle but require correction. Finally, some Staff and intervenor operating income pro forma adjustments are addressed by APS witnesses Jacob Tetlow, Jamie R. Moe, Jessica E. Hobbick, Dr. Kim Kateregga, Chris R. Bauer, and Theodore N. Geisler in their Rebuttal Testimonies.

Rebuttal SFR Schedules A-1, B-1, B-2, C-1, C-2, and C-3 are updated to reflect the updated pro forma adjustments I describe. Rebuttal SFR Schedules B-1 through C-3 are attached to my Rebuttal Testimony as Attachments EAB-01RB through EAB-05RB, respectively, while Rebuttal SFR Schedule A-1 is attached to Mr. Moe's Rebuttal Testimony. I am sponsoring the Total Company column for the adjustments I have listed above and those discussed in my Rebuttal Testimony.

All jurisdictional allocations shown on the SFRs are sponsored by Mr. Moe. The overall change in the Company's rate request, which includes these revisions, is addressed in the Rebuttal Testimonies of Ms. Hobbick and Mr. Moe.

III. ADJUSTMENTS TO REVENUE REQUIREMENT IN RESPONSE TO INTERVENOR DIRECT TESTIMONY

Q. DOES APS AGREE WITH THE METHODOLOGY USED IN STAFF WITNESS RALPH C. SMITH'S CASH WORKING CAPITAL ADJUSTMENTS?

A. Yes. APS agrees with the proposed methodology used by Mr. Smith and agrees that an adjustment to Cash Working Capital (CWC) is necessary to reflect Test Year revenues and expenses updated in rebuttal.[1] As I discuss below, APS is proposing changes to certain pro forma adjustments, and those updates are reflected in the Company's CWC adjustment. This is a customary rebuttal adjustment and follows the same methodology APS used in its initial filing, and includes the values proposed in my Rebuttal Testimony (*see* Attachment EAB-02RB, column 8, and Attachment EAB-04RB, column 39). As APS's adjustments may differ from Mr. Smith's adjustments, there will be a difference in the calculated amount.

Q. DOES APS AGREE WITH THE METHODOLOGY USED IN MR. SMITH'S INTEREST SYNCHRONIZATION ADJUSTMENT?[2]

A. Yes. APS agrees with the methodology and agrees that an adjustment to interest synchronization is necessary to reflect Test Year rate base as adjusted. APS's pro forma changes are reflected in the Company's interest expense adjustment as shown on line 16 of Attachment EAB-04RB. This adjustment is also customary in rebuttal, follows the same methodology APS used in the initial filing, and contains

[1] Staff, Direct Testimony of Ralph C. Smith (March 2, 2026) (Smith Direct) at 33-34.
[2] *Id.* at 79.

the values proposed in my Rebuttal Testimony (*see* Attachment EAB-04RB, column 33). As APS's adjustments may differ from Mr. Smith's adjustments, there will be a difference in the calculated amount.

Q. DOES APS AGREE WITH STAFF'S RECOMMENDATION TO UPDATE THE INTEREST ON CUSTOMER DEPOSITS?

A. Yes. APS agrees that the most recent customer deposit interest rate of 3.47%, effective on January 6, 2026, is appropriate to include.[3] Updating the interest rate on customer deposits is a customary rebuttal adjustment that the Company has made in previous rate cases. This practice ensures that the rate accurately reflects the prevailing interest rates. APS is therefore proposing to adjust the Test Year pro forma to reflect this rate (*see* Attachment EAB-04RB, column 22).

Q. HAS APS REMOVED THE NAVAJO GENERATING STATION (NGS) COAL RECLAMATION REGULATORY ASSET FROM RATE BASE?

A. Yes. The Navajo Generation Station Coal Reclamation Regulatory Asset was authorized to be amortized over the original life of the plant, through 2026, in Decision No. 78317.[4] Given the timeline of this rate case, APS expects that the asset will be fully amortized by the rate effective date. As such, this rate base pro forma adjustment removes the asset from the Test Year, resulting in a reduction to rate base of $7.905 million (*see* SFR Schedule B-2, column 17). This adjustment is supported in the testimony of Staff, AZLCG, RUCO and Freeport Minerals Corporation (Freeport).[5] As noted in my prior testimony filed with the application, the amortization cost associated with the Navajo Generation Station Coal

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[3] *Id.* at 67-68.

[4] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Prop. for Ratemaking Purposes*, Docket No. E-01345A-19-0236, Decision No. 78317 (Nov. 9, 2021) (Decision No. 78317).

[5] Smith Direct at 39-40; AZLCG, RUCO, and Freeport, Direct Testimony of Courtney M. Higgins (Mar. 2, 2026) (Higgins Direct) at 31-33.

Reclamation was also removed from the Test Year through an income statement pro forma adjustment (*see* SFR Schedule C-2, column 38).

Q. HOW DOES APS RESPOND TO THE PROPOSALS OF AZLCG, RUCO, AND FREEPORT WITNESS COURTNEY M. HIGGINS AND MR. SMITH TO REDUCE DIRECTORS AND OFFICERS (D&O) INSURANCE BY 50%?[6]

A. D&O insurance costs are a necessary expense and prudently incurred, and as such, 100% recovery is appropriate. However, APS is willing to accept the 50% reduction of D&O insurance costs to limit the contested issues in this case. Please see Mr. Geisler's Rebuttal Testimony for a discussion on the importance of D&O insurance. As discussed below, APS is including a new pro forma adjustment reflecting a 50% D&O insurance reduction (*see* Attachment EAB-04RB, column 64).

Q. DO YOU AGREE WITH THE PROPOSALS OF MS. HIGGINS AND MR. SMITH TO REDUCE BOARD OF DIRECTORS' FEES BY 50%?[7]

A. Because APS is required by law to have a Board of Directors, the Company's position is that these costs are prudently incurred and 100% recovery is appropriate. However, APS is willing to accept the 50% reduction of Board of Directors Fees in this specific case. Please see Mr. Geisler's Rebuttal Testimony for a discussion on the importance of Board of Directors Fees. As discussed below, APS is including a new pro forma adjustment reflecting a 50% Board of Directors Fee reduction (*see* Attachment EAB-04RB, column 63). On a Total Company basis, the pro forma adjustment removes $1.718 million of costs from Test Year.

[6] Higgins Direct at 52-53; Smith Direct at 69.

[7] Higgins Direct at 51-52; Smith Direct at 70-72.

Q. DOES APS ACCEPT THE PROPOSALS FROM STAFF, AZLCG, RUCO, AND FREEPORT REGARDING CASH INCENTIVE COMPENSATION?[8]

A. Yes. While the Company maintains that APS's incentive plan benefits customers and the associated expenses are prudently incurred, thus warranting 100% recovery, APS accepts, in this specific case, a 50% reduction in the cost of incentive compensation and removal of normalization *(see* Attachment EAB-04RB, column 32). As the Company has expressed in the past, normalization is appropriate for this type of expense, but under the facts of this case, the Company is willing to accept Staff's recommendation. Mr. Geisler further discusses the importance of incentive compensation in his Rebuttal Testimony.

Q. DO YOU AGREE WITH MS. HIGGINS' UPDATE TO REFLECT 2025 ACTUALS FOR PENSION EXPENSE?[9]

A. Yes. APS agrees that the Test Year Operating Costs should be updated in rebuttal to reflect the actual 2025 pension and Other Post-Employment Benefits (OPEB) expenses. APS has updated the proposed pro forma adjustment to normalize the Test Year employee benefits to reflect the 2025 actual expense (*see* Attachment EAB-04RB, column 28). This update to actual 2025 costs normalizes the Test Year pension and OPEB costs to more appropriately reflect the cost of service applicable at rate effective date and aligns with the approach accepted by Staff[10] and intervenors, such as AZLCG, RUCO, and Freeport[11].

[8] Higgins Direct at 47-50; Smith Direct 73-74.
[9] Higgins Direct at 51.
[10] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Prop. for Ratemaking Purposes*, Docket No. E-01345A-22-0144, Decision No. 79293 (Mar. 5, 2024) (Decision No. 79293) at 107:5-7.
[11] Higgins Direct at 7.

IV. POST-TEST YEAR PLANT (PTYP)

Q. IS APS UPDATING ITS PTYP REQUEST?

A. Yes. As discussed by Mr. Tetlow, the Company provided an update to its PTYP request in discovery and Staff agrees with including all plant additions that went into service by December 31, 2025, within rate base. The updated request reflects an $894 million increase to rate base as shown on Attachment EAB-02RB, columns 2-6.

Q. DO YOU AGREE WITH AZLCG, RUCO, AND FREEPORT'S PROPOSAL TO REFLECT REVENUE GROWTH FROM THE PTYP PERIOD IN APS'S REVENUE REQUIREMENT?

A. No. This proposal fails to recognize that APS has already adjusted for growth through project exclusions in PTYP. The Commission heard and rejected their proposed method in APS's last rate case, noting that "recognition of [Post-Test Year] revenues would reduce the regulatory lag mitigation that allowing for PTYP provides."[12] Further, APS has appropriately excluded growth related- plant from its PTYP request in accordance with Decision No. 79293—all of the Company's included PTYP investments are necessary to provide reliable service to Test Year customers.[13] The Commission itself recognized in its order adopting the requirement that APS address revenue-producing plant among the Company's PTYP investments that APS would need to "impute net revenue growth for any revenue producing plant *included* in post-test year plant."[14] (Emphasis added). The Company, therefore, excluded growth-related plant from its PTYP request, and, by doing so, also did not need to reflect the revenues associated with that plant.

[12] Decision No. 79293 at 59.

[13] APS Supplemental Response to AZLCG DR 11.1, Attachment AZLCG 11.01_ExcelAPS25RC02090_Growth-related Projects Excluded from PTYP.

[14] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Property for Rate Making Purposes,* Docket No. E-01345A-16-0036, Decision No. 76295 (Aug. 18, 2017) (Decision No. 76295) at 108.

Accordingly, adjusting revenues separately to reflect growth would result in double counting the effects of growth. If a growth adjustment were made to revenue, the Company would need to revise its PTYP request to include the growth-related projects that were excluded, as well as additional expense increases associated with customer growth.

As with the recommendations in APS's last rate case to reflect post-Test Year Revenue in the Company's PTYP recovery, Ms. Higgins' position in this proceeding is still an "estimate[]" based on an averaging of assumed sales growth.[15] As the Commission recognized in Decision No. 79293, using estimates in this context is problematic.[16] Given that Ms. Higgins' recommendations in this proceeding still suffer from the same flaws identified by the Commission in APS's last rate case, this proposal should be rejected once again.

As Mr. Smith explains, mismatches related to PTYP can occur if gross plant in service additions are reflected, but corresponding changes in accumulated depreciation are ignored.[17] However, as discussed further below, APS has reflected the roll forward in Test Year accumulated depreciation and taxes through December 31, 2025, an $800.4 million decrease to rate base, which aligns with the PTYP period.[18] APS agrees with Mr. Smith that the largest component of rate base is based on net plant in service and that this treatment resolves any potential issues related to the matching principle.

[15] Higgins Direct at 41.
[16] Decision No. 79293 at 58-59.
[17] Smith Direct at 19.
[18] *Id.* at 19.

Q. DO YOU AGREE WITH RUCO AND AZLCG/FREEPORT'S PROPOSAL TO REFLECT ACCUMULATED DEPRECIATION ON PTYP? [19]

A. No. APS has a long-standing and well-accepted methodology of including 12 months of accumulated depreciation and taxes on Test Year rate base as a reduction to PTYP. In this rate case, the rolling-forward of 12 months of Test Year accumulated depreciation and taxes results in a reduction to the PTYP request of $800.4 million. This roll-forward of Test Year plant accumulated depreciation and taxes provides enormous benefits to customers by offsetting the rate base increase associated with PTYP. This approach is consistent with the methodology applied and approved in APS's prior rate cases, and APS has a long-standing and well-supported practice of applying this PTYP methodology.[20] Staff and the Commission have been supportive of this methodology[21] and there is no basis to make a change in this case considering the current methodology both provides benefits to customers and reduces regulatory lag.

V. UPDATES TO PRO FORMA ADJUSTMENTS TO THE TEST YEAR

Q. IS APS UPDATING ANY OTHER PRO FORMA ADJUSTMENTS THAT WERE INCLUDED IN THE COMPANY'S APPLICATION?

A. Yes. APS is updating the following pro forma adjustments to reflect actual costs to date, including known adjustments identified in the discovery process, and including effects and synchronization of the updated pro formas. I sponsor the Total Company portion of the following updated pro formas:

- *Normalize Wildfire Operations and Maintenance (O&M) Costs* – updated to reflect the actual 2025 wildfire mitigation O&M costs. Normalization of O&M wildfire costs was supported by Mr. Ralph Smith. (*see* Attachment EAB-04RB column 48);

[19] Higgins at 22
[20] Decision No. 78317 at 125.
[21] Decision No. 79293 at 58.

- *Include Wildfire Mitigation O&M Cost Accumulation* – updated to reflect the actual 2025 wildfire mitigation O&M costs incurred, and the 2026 forecasted spend through September 2026. The comparison to cost recovery in current rates was corrected to capture the appropriate matching time period. While Staff supported normalization of wildfire O&M costs, Mr. Smith does not support the rate base regulatory asset treatment proposed in this adjustment.[22] Additional discussion is provided below regarding this adjustment. (*see* Attachment EAB-02RB, column 11);
- *Include Wildfire Mitigation O&M Expense Accumulation Amortization* – updated to reflect amortization impacts driven by changes in cost accumulation described above (*see* Attachment EAB-04RB, column 46);
- *Adjust for Palo Verde Lease Buyback Costs* – updated property tax assumptions and estimated depreciation and amortization costs based on actual known Federal Energy Regulatory Commission (FERC) accounts that were used to record the asset purchase. Please refer to Rebuttal Testimonies of APS witnesses Michael Eugenis and Mr. Tetlow for further discussion on the significant value this transaction delivers to customers. (*see* Attachment EAB-04RB, column 56);
- *Include E-3/E-4 Customer Bill Payment Fees Deferral* – updated to include actual costs through December 31, 2025, and updated estimated costs through September 30, 2026 (*see* Attachment EAB-02RB, column 12 and EAB-04RB, column 25);
- *Remove Buckeye Service Center* – updated to reflect the known net book value of assets removed from Test Year plant in service (*see* EAB-02RB, column 16);

[22] Smith Direct at 79-80.

- *Adjust and Annualize Four Corners Inventory* – updated to include actual inventory cost through December 31, 2025 (*see* Attachment EAB-04RB, column 49);
- *Remove Out of Period and Miscellaneous Items* - updated for known adjustments identified in the discovery process and to remove an additional $0.37 million. Additional discussion is provided below regarding the scope of this adjustment. (*see* Attachment EAB-04RB, column 62);
- *Include Cholla Unrecovered Costs Net of Prospective Customer Rate Benefit* - This pro forma adjustment updates for known adjustments and synchronization of activities in 2025; including an adjustment necessary to account for the absence of a deferral order while retaining customer rate benefits. While APS had previously sought a deferral order for Cholla related costs in 2024, following APS's filing of its rate Application, APS withdrew its Cholla-related deferral application in July 2025. Additional discussion regarding this adjustment is provided below. (*see* Attachment EAB-02RB, column 13);
- *Include Amortization of Cholla Unrecovered Costs and Prospective Customer Rate Benefit* - This is a new pro forma adjustment that amortizes rate base and provides the prospective customer benefit over a 10-year period, which provides customers a net benefit of $7.0 million annually. While this is a new pro forma adjustment, the same rate benefits updated through rebuttal were included and amortized within the Cholla decommissioning costs amortization pro forma provided in APS's June 2025 application in this proceeding. As no deferral order was obtained, APS has no ability to offset the recovery of decommissioning costs and must provide the benefits in this separate pro forma adjustment. Additional

discussion regarding this issue is provided below. (*see* Attachment EAB-04RB, column 65); and

- *Include Amortization of Cholla Decommissioning Costs* - Updated for 2025 decommissioning study and coal combustion residual (CCR) costs. Study cost estimates have increased, resulting in an updated amortization adjustment. APS also removed the deferral order amortization component that was included in the original request, as no deferral order was issued, given APS's withdrawal of its previous deferral application in July 2025. Additional discussion regarding this issue is provided below. (*see* Attachment EAB-04RB, column 58).

Q. DO YOU AGREE WITH STAFF'S RECOMMENDATION TO DENY APS'S REQUEST TO ACCUMULATE AND PLACE INTO A REGULATORY ASSET THE WILDFIRE MITIGATION O&M ITEM?[23]

A. No. APS has been required to fund dramatically increasing wildfire mitigation costs that are significantly under-recovered in current rates. Mr. Tetlow and Mr. Bauer, in their Direct Testimonies, describe the extraordinary nature of these expenses that are entirely outside of APS's control. APS rates are currently set at levels to recover $5.0 million of fire mitigation costs annually. In 2025, APS's fire mitigation costs exceeded $17.8 million. Between 2021 and 2025, APS rates have under-recovered wildfire mitigation O&M costs by over $89 million. Based on the Company's 2026 forecast, APS expects over $104 million of wildfire mitigation O&M costs will be under recovered by the expected rate effective date in this proceeding. Of this $104 million, APS is seeking regulatory asset treatment for $27.9 million, representing only a small portion of these under recovered costs.

[23] Smith Direct at 37-38 and 79-80

Q. IF THESE WILDFIRE MITIGATION EXPENSES REPRESENT O&M COSTS, WHY IS IT APPROPRIATE FOR THESE COSTS TO BE RECOVERED IN A REGULATORY ASSET?

A. If the requested regulatory asset treatment is approved, APS will still have lost $76 million of O&M costs that will never be recovered in rates due to regulatory lag. In addition to these lost direct O&M costs, APS had to use limited debt and equity capital resources—with no corresponding cash flows from rates—to fund these critical O&M costs necessary to help keep APS customers and the communities we serve safe from wildfires. While necessary to ensure safe and reliable operations, this situation results in additional under-recovery as to APS's cost of capital. The proposed regulatory asset treatment would allow APS a method to partially recover a component of these under-recovered costs, including a return of APS's capital used to fund these O&M costs. This treatment partially offsets the financing costs associated with providing a return to APS's lenders who provided the needed capital to ensure critical expenses would be covered.

Q. IF APS'S PROPOSAL FOR A FORMULA RATE ADJUSTMENT MECHANISM (FRAM) IS ADOPTED IN THIS PROCEEDING, IS THIS REGULATORY ASSET TREATMENT STILL NECESSARY?

A. Yes. In future periods, the FRAM will address these types of variable costs; however, APS needs a mechanism to provide some rate relief for the past costs that rapidly increased over the most recent five-year period. APS has been required to fund extraordinary costs that are outside of APS's control, and requests Commission support to alleviate some of this regulatory lag today. APS has also requested to normalize Test Year wildfire costs, which Staff supports. The normalization of Test Year costs helps set future rates at appropriate cost levels providing future relief regarding these rising costs, but does not provide recovery for these past, under-recovered costs.

Q. PLEASE EXPLAIN WHY THERE ARE NECESSARY CHANGES TO THE PRO FORMA ADJUSTMENTS RELATING TO CHOLLA POWER PLANT (CHOLLA).

A. APS's original rate application in this docket was premised on the Commission's pending consideration of a separate APS application for a deferral related to Cholla costs and revenues, which was filed on August 14, 2024. [24] The Cholla adjustment pro formas filed with my Direct Testimony reflected this deferral order request. Since the original filing in this pending rate application, APS subsequently withdrew the prior application for a deferral order relating to Cholla in July of 2025. Given the passage of time since the application was filed and the administrative efficiency of handling those Cholla related costs and revenues in this pending rate case docket, APS determined that the pending application under Docket E-01345A-24-0185 was no longer necessary.

As such, APS has updated the pro forma adjustments to reflect the absence of a deferral order. Nonetheless, the Rebuttal pro forma adjustments and related updates are structured to achieve the same rate outcome as what was contained in APS's original rate case application. In the spirit of customer affordability, the customer benefit is being maintained and achieved through a prospective rate reduction over 10 years.

Lastly, the Rebuttal pro forma includes a normal refresh of updated costs and activity. This includes the correction related to $3.4 million of net rate base assets that have not been retired and, therefore, should remain in rate base. These assets were transferred and reclassified as general plant to serve APS's Northern region

[24] *In the Matter of the Application of Ariz. Pub. Serv. Co. for an Accounting and Deferral Order, etc.,* Docket No. E-01345A-24-0185.

service territory. These assets include the plant security center, administration building, warehouse office, vehicle maintenance bay, and various communication equipment. In addition, the Cholla real property, with a net book value of approximately $5 million, is currently included in rate base because it continues to be used for the remediation activities associated with the cessation of coal-fired electricity generation at the site. However, the land is no longer used for power generation. This will be addressed in APS's upcoming Rejoinder Testimony, which will reclassify the land to "future use" and remove it from rate base.

Q. WHAT CHANGES TO THE PRO FORMA ADJUSTMENTS FOR CHOLLA ARE NECESSARY TO ACHIEVE THE SAME RATE OUTCOME AS WHAT IS CONTAINED IN YOUR DIRECT TESTIMONY?

A. When APS filed the Company's direct application and the original Cholla pro forma adjustments, the deferral request was pending and the pro forma adjustments were presented as if the deferral would be approved, which included the establishment of regulatory accounts. Because the deferral request was withdrawn and not approved, the Company does not have a mechanism to establish regulatory accounts. Thus, it was necessary to change the presentation and labeling of the pro formas in order to achieve the same rate outcome and preserve the customer benefit as a prospective reduction to rates.

As such, APS's Rebuttal pro forma adjustment reflects the income statement adjustment as two separate adjustments as opposed to a combined adjustment as filed in the direct application. This presentation is consistent with the direct application pro forma support schedule and currently shows them as two separate pro forma adjustments in SFR C-2, page 20, column 58. One pro forma adjustment reflects the recovery of the future decommissioning, CCR remediation, and removal costs for the Cholla site over a 10-year period. The second adjustment is

the rate base amortization and prospective customer rate benefit utilizing a 10-year period. This structure retains the related rate outcome as filed in my Direct Testimony, with updates for activities and synchronization for 2025 activities, and provides recovery for APS in the future as to prudently incurred Cholla site remediation and decommissioning costs.

Q. DOES THE COMPANY REQUEST THAT ANY FINAL ORDER IN THIS RATE CASE CONTAIN SPECIFIC LANGUAGE RELATED TO ACHIEVING THE SAME RATE OUTCOME AS IS CONTAINED IN YOUR DIRECT TESTIMONY?

A. Yes. The Company requests that the final decision explicitly include the following language:

"IT IS FURTHER ORDERED that, with respect to the amortization of Cholla unrecovered costs and prospective customer rate benefit pro forma, APS will provide a customer rate benefit as a prospective rate reduction to customers over a 10-year period."

Q. DOES THE COMPANY REQUEST THAT THE FINAL ORDER IN THIS RATE CASE CONTAIN SPECIFIC LANGUAGE ADDRESSING THE AMORTIZATION OF CHOLLA DECOMMISSIONING COST PRO FORMA ADJUSTMENT?

A. Yes. The Company requests that the final decision explicitly include the following language:

"IT IS FURTHER ORDERED that APS shall be authorized to recover in customer rates the current estimates of future decommissioning, coal combustion residual remediation, and other removal costs for the Cholla Power Plant site over a 10-year period. Nothing in this Decision shall be construed in any way to limit the Commission's authority to make any disallowances thereof due to imprudence, errors, or inappropriate application of the requirements of this Decision."

Q. IS APS REQUESTING RECOVERY IN RATES OF LOBBYING EXPENSES, CHARITABLE DONATIONS, SPONSORSHIPS OR MARKETING AND ADVERTISING EXPENSES THAT EXTEND BEYOND EDUCATIONAL CONTENT TIED TO COMMISSION-APPROVED PROGRAMS?

A. No. Non-operating costs that are recorded "below the line" are excluded from the Test Year and customer rates by their very nature. These include expense items identified by Arizona Public Interest Research Group Education Fund (AZ PIRG) witness Diane E. Brown, such as lobbying, charitable donations, and sponsorships.[25] Pro forma adjustments are not required to remove these kinds of non-operating costs as these costs are inherently excluded from the Test Year costs and, ultimately, customer rates for service. Other costs that the Commission directed the Company not to include in customer rates, such as certain marketing and advertising expenses that are not strictly educational in nature or not directly tied to a specific Commission-approved program, rate plan, or tariff,[26] have been removed through the Remove Advertising Expense pro forma adjustment discussed in my Direct Testimony and reflected in SFR Schedule C-2. Since the costs identified by Mr. Brown are already excluded from Test Year costs, any further adjustment would duplicate the exclusion and be inappropriate in setting customer rates.

[25] AZ PIRG, Direct Testimony of Diane E. Brown (Mar. 18, 2026) at 3-4.
[26] Decision No. 79293 at 406-407.

VI. MISCELLANEOUS

Q. DO YOU AGREE WITH MS. HIGGINS' PROPOSAL TO SET THE RETURN ON THE PREPAID PENSION ASSET TO THE LESSER OF APS'S WEIGHTED AVERAGE COST OF CAPITAL (WACC) OR THE PENSION ASSET'S EARNED RETURN ON ASSET (EROA)?

A. No. This proposal has been considered and rejected in prior Commission decisions (s*ee e.g.,* Decision No. 79293, Decision No. 78317, Decision No. 76295, Decision No. 73183 (May 24, 2012),[27] Decision No. 71448 (December 30, 2009)[28]). More importantly, it does not align with standard ratemaking principles or the fundamental economic nature of how these principles are applied. It is a standard and well-accepted rate-making practice that a utility's WACC is applied to total "net" rate base (rate base additions less rate base deductions) to calculate the return component applicable. By contrast, as proposed by Ms. Higgins, the EROA is applied directly to the "gross" pension and OPEB assets themselves as a reduction to benefit costs.[29]

Q. WHAT IS THE "EROA" AND HOW DO CUSTOMERS BENEFIT FROM SUCH RETURNS ON THE GROSS PENSION AND OPEB RATE BASE ASSETS?

A. The EROA is the long-term annual rate of return that a pension fund expects to earn on pension plan investments. The EROA reduces the net periodic pension costs. Customers are receiving a benefit of the earnings on the entire amount of the assets in the pension trust as a reduction to annual pension costs. The net prepaid

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[27] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Property for Rate Making Purposes,* Docket No. E-01345A-11-0224, Decision No. 73183 (May 24, 2012) (Decision No. 73183).

[28] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Property for Rate Making Purposes*, Docket No. E-01345A-08-0172, Decision No. 71448 (Dec. 30, 2009) (Decision No. 71448).

[29] Higgins Direct at 61.

pension asset in rate base represents the cumulative contributions made by the Company over the accumulated net of periodic costs. The source of the funding that results in a net prepaid pension asset has been provided by the Company's capital partners. Thus, the customer is earning returns through a reduction to net periodic pension costs on amounts that customers have not yet paid. Customers directly benefit from this lower pension cost. In addition, customers also benefit from lower Pension Benefit Guaranty Corporation (PBGC) premium expenses, given that the EROA helps ensure that APS's pension is sufficiently funded in accordance with regulatory guidelines and industry best practices. Collectively, this approach results in lower pension costs and provides greater economic benefits to the customer than what the Company would receive from inclusion of the prepaid pension asset in rate base with a WACC-level return.

Q. WHY WOULD IT BE INAPPROPRIATE TO SET A RETURN BASED ON A METRIC DIFFERENT THAN THE COMPANY'S WACC?

A. It would be inconsistent, inequitable, and unreasonable to deny the Company a return on the prepaid pension asset at anything other than the WACC. Attempting to segregate rate base components, and providing alternative returns to individual asset and liability components, would have downstream impacts complicating and compounding the rate setting process. If an EROA-level return is applied to the prepaid pension asset, additional analysis would be needed on the overall WACC to assess the additional returns necessary to mitigate the modified treatment of rate base returns. Further, the Commission has previously ordered that the return allowed on these assets and liabilities in rate base should be at the Company's WACC.[30] For example, the Commission explicitly stated in APS's 2019 rate case order that "there is no compelling reason to depart from the normal treatment of

[30] Decision No. 78317 at 181-182.

the return allowed on assets that are appropriately included in rate base."[31] Ms. Higgins' proposal would modify a well-accepted rate making approach of applying a WACC to net rate base. There is no basis that this long-standing rate setting practice should be modified, as is being proposed.

As previously stated, the prepaid pension asset benefits customers through the return they effectively earn on the prepaid asset through the EROA. Investor funding reduces the pension obligation, reduces PBGC premiums, and results in a higher EROA, which directly benefits customers through lower cost of service. These inter-related components illustrate that providing an EROA return on the asset is unjust and unreflective of the Company's costs. As such, the pension asset is a functional tool that produces long-term customer benefits that enable reliable service to customers, and it would be wholly inequitable to treat it differently from all other APS assets earning a WACC return on net rate base.

Q. DO YOU AGREE WITH MS. HIGGINS' PROPOSAL TO REMOVE INFLATION ESCALATION FROM THE NORMALIZATION OF GENERATION OVERHAUL EXPENSES?[32]

A. No. APS's maintenance expense normalization methodology, including the application of escalation factors, is a well-established and reasonable approach that the Commission has consistently accepted in prior APS rate cases.[33] Escalation

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[31] *Id* at 183.

[32] Higgins Direct at 55.

[33] *See In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Property for Rate Making Purposes,* Docket No. E-01345A-03-0437, Decision No. 67744 (Apr. 7, 2005); *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Property for Rate Making Purposes,* Docket No. E-01345A-05-0816, Decision No. 69663 (Jun. 28, 2007); Decision No. 71448; 73183 (May 24, 2012) (Decision No. 73183), *In the Matter of the Application of Arizona Public Service Corporation for a Hearing to Determine the Fair Value of the Utility Property of the Company for Rate Making Purposes, etc.*, Docket No.

factors ensure that the revenue requirement calculated using a historical Test Year reasonably reflects the costs the Company will incur during the period when new rates are in effect. Without these adjustments, the use of historical costs would understate the Company's expected expenses due to inflation and other cost pressures.

Q. WHY DOES APS APPLY ESCALATION FACTORS IN ITS MAINTENANCE NORMALIZATION PRO FORMA?

A. APS applies escalation factors in its maintenance normalization pro forma to adjust historical costs for changes in labor and material costs over time to reflect current levels. These escalation factors help mitigate the effects of inflation and regulatory lag inherent in traditional rate case processes. The Company relies on the Handy-Whitman indices, which are widely recognized and commonly used in the utility industry to adjust historical utility cost data to current cost levels.[34]

E-01345A-16-0036, Decision No. 76295 (Aug. 18, 2017); *In the Matter of the Application of Arizona Public Service Corporation for a Hearing to Determine the Fair Value of the Utility Property of the Company for Rate Making Purposes, etc.*, Docket No. E-01345A-19-0236, Decision No. 78317 (Nov. 9, 2021); *In the Matter of the Application of Arizona* Decision No. 73183; Decision No. 76295; Decision No. 78317; Decision No. 79293. *Public Service Corporation for a Hearing to Determine the Fair Value of the Utility Property of the Company for Rate Making Purposes, etc.*, Docket No. E-01345A-22-0144, Decision No. 79293 (March 5, 2024).

[34] The Handy-Whitman Index of Public Utility Construction Costs is an annually published index for trends in utility construction costs. The index is designed to collect publicly available data reported to the Federal Energy Regulatory Commission to be a reasonably accurate measure of the cost of reproducing actual plant. The index is widely used by regulatory bodies, valuation experts, and regional transmission organizations to estimate cost trends, which are then applied to known original costs of similar plant and property to determine the fluctuation in costs.

Q. DO YOU AGREE WITH MS. HIGGINS' PROPOSAL TO REMOVE ROUTINE MAINTENANCE EXPENSES FROM APS'S MULTI-YEAR NORMALIZATION OF GENERATION MAINTENANCE COSTS AND ALTERNATIVELY INCLUDE ROUTINE MAINTENANCE COSTS AT ACTUAL TEST YEAR AMOUNTS?[35]

A. No. Routine maintenance expenses are a necessary and ongoing component of maintaining safe and reliable generation operations. These expenses are subject to cost pressures similar to other maintenance activities, including increases in labor and material costs. Excluding routine maintenance from the normalization methodology would arbitrarily treat a portion of generation maintenance expenses differently from other maintenance costs without a sound analytical basis.

APS normalizes fossil generation maintenance expenses using a six-year maintenance cycle and nuclear maintenance expenses using a three-year maintenance cycle. Over these periods, maintenance costs fluctuate significantly from year to year due to the timing of outages, overhaul activities, and other operational factors. Normalization smooths these cyclical variations, but escalation is also necessary to ensure that the resulting normalized expense reflects the cost levels that will prevail during the rate effective period. Even absent general inflation, the cost of performing maintenance work typically increases over time due to evolving labor, equipment, and material costs.

Q. WHY IS APS'S USE OF ESCALATION FACTORS AND ITS INCLUSION OF ROUTINE MAINTENANCE IN NORMALIZED GENERATION MAINTENANCE EXPENSES REASONABLE?

A. Recent economic conditions demonstrate the importance of escalation. Over the past several years, APS has experienced significant increases in the costs of labor,

[35] Higgins Direct at 55.

materials, and contractor services associated with generation maintenance. These increases have been driven in part by supply chain disruptions and broader inflationary pressures.

For instance, maintenance labor costs have increased, including wage expense escalation, the provision of overtime pay, and craft availability constraints during outage periods, which directly affect the cost of executing maintenance work. At the same time, supply chain conditions for generation equipment and materials have tightened due to heightened nationwide demand for energy infrastructure, longer manufacturing lead times, and disruptions affecting global suppliers that resulted in higher pricing and increased logistics complexity for critical components. In addition, changing operating conditions have contributed to higher maintenance intensity. Taken together, these factors mean that the cost of performing maintenance in 2026 will be higher than the cost of performing similar work several years earlier, and escalation is necessary to ensure normalized expenses reasonably reflect expected costs during the rate-effective period.

Without the use of escalation factors, APS's normalized maintenance expenses would understate the current cost of maintaining its generation fleet.

Q. IS APS'S APPROACH CONSISTENT WITH COMMISSION PRECEDENT?

A. Yes. APS's approach is consistent with long-standing Commission precedent. For more than two decades, APS has normalized generation maintenance expenses and applied escalation factors based on the Handy-Whitman indices in its rate cases, and the Commission has repeatedly found this methodology to be reasonable. APS's proposal in this proceeding simply continues that established practice so

that the Test Year costs used in this case reasonably reflect the costs the Company expects to incur during the period when rates are in effect.

For these reasons, I recommend that the Commission reject Ms. Higgins' proposed adjustments and adopt APS's generation maintenance normalization methodology, including the application of escalation factors and the inclusion of routine maintenance expenses.

Q. HOW DO YOU RESPOND TO MS. HIGGINS' RECOMMENDATION THAT THE COMMISSION DISCONTINUE RECOVERY OF THE NGS REGULATORY ASSET?

A. I disagree with Ms. Higgins' recommendation.[36] Her proposal is inconsistent with the Commission's prior decisions regarding the NGS regulatory asset and reflects a misunderstanding of how regulatory assets are recovered through the ratemaking process.

In APS's 2019 rate case, the Commission addressed the recovery of the remaining net book value of NGS in Decision No. 78317. In that decision, the Commission authorized APS to recover the remaining book value of NGS through a regulatory asset that would be amortized over the original life of the plant through 2026 while earning a return at APS's approved WACC. The Commission then determined that 15% of the annual amortization expense should be disallowed, but it did not direct APS to remove any portion of the regulatory asset from rate base, nor require APS to receive a lower return on the regulatory asset.[37] The Commission specifically addressed this rate-making treatment in that decision, and affirmed that no adjustment to rate base was required. APS has consistently applied this ratemaking

[36] Higgins Direct at 38.
[37] Decision No. 78317 at 202-203.

treatment since the Commission issued Decision No. 78317, including in the Company's 2022 rate case, which was accepted in the final Commission rate order.[38] The annual amortization cost of the regulatory asset established in Decision No. 78317 and included in this Test Year is $9.6 million.[39] Consistent with Decision No. 78317, in this rate proceeding APS has recorded 15% ($1.4 million) of the annual amortization cost included in the Test Year below the line as a non-operating expense, and APS does not seek to recover this cost in rates (SFR Schedule B-2 column X).[40]

Q. DO YOU AGREE WITH MS. HIGGINS' RECOMMENDATION THAT THE COMMISSION SHOULD REMOVE FROM RATE BASE THE NGS REGULATORY ASSET?

A. No. The NGS regulatory asset should not be removed from rate base. Ms. Higgins suggests that the regulatory asset should have been fully amortized by 2026 and, therefore, should be eliminated from rates.[41] Ms. Higgins fails to recognize regulatory asset rate making treatment and that the annual amortization level established in Decision No 78317, has not been subsequently increased to fully amortize this regulatory asset by 2026. Decision No. 78317 established the regulatory asset and the annual amortization cost on the rate effective date of December 1, 2021. The 2019 rate case used a Test Year ending June 30, 2019, resulting in an approximately two-and-a-half year lag in the establishment and amortization of the regulatory asset. Subsequently to Decision 78317, to have fully amortized the regulatory asset by 2026, the annual amortization level could have been adjusted and increased in both the 2022 rate case proceeding and in this current proceeding. This would have resulted in an increase in customer rates to

[38] Decision No. 79293.
[39] Decision No. 78317.
[40] Decision No. 78317.
[41] Higgins Direct, at 38–39.

accelerate the recovery of the regulatory asset and ensure the asset was fully amortized by 2026. To avoid customer rate increases, the annual amortization level of $9.6 million that was established in No. Decision 78317 has been retained in both the 2022 rate case and in this current proceeding. As a result of regulatory lag the NGS regulatory asset and amortization cost established in Decision No. 78317, will not be fully amortized until beyond 2027. This is beyond the expected rate effective of this proceeding and, thus, no adjustment to remove the regulatory asset from rate base is warranted in this rate case.

For these reasons, Ms. Higgins' recommendation to discontinue recovery of the NGS regulatory asset and remove it entirely from rates is inconsistent with the Commission's prior decisions and established ratemaking practice.[42] APS's approach to amortize the regulatory asset utilizing the annual amortization rate established in Decision No. 78317, while excluding 15% of the amortization expense from recovery appropriately implements the Commission's directive in Decision No. 78317 and should be maintained.

Q. IS THE COMPANY MAKING CHANGES TO ITS DEPRECIATION BASED ON FEA'S TESTIMONY ON CURVE RETIREMENTS?

A. No. Curve Retirements (also referred to as "RETIRE_CURVE") is an option available in the PowerPlan accounting system that APS uses to automate the estimation of vintage years and pricing of retirements (automatic aging). Estimation of retirements (or automatic aging) is an accounting record-keeping methodology for mass property, applied when asset-specific retirement vintage information is impracticable to identify, which is common for large populations of assets such as poles, conductors, and conduit. In these circumstances, automatic aging provides a systematic, auditable means, commonly used for mass property

[42] Higgins Direct at 38-39.

in the utility industry, to assign recorded retirement quantities to installation vintages, consistent with longstanding mass property accounting principles. This approach is contemplated under the FERC Uniform System of Accounts,[43] recognized in IRS regulations[44] applicable to mass assets and described in Edison Electric Institute and American Gas Association guidance,[45] all of which acknowledge that estimation techniques are appropriate when exact vintage detail cannot reasonably be determined. Importantly, automatic aging does not create or accelerate retirement quantities; rather, it determines the age and price of recorded retirements within the Company's records. Accordingly, the use of automatic aging is appropriate, reasonable, and consistent with utility accounting requirements. In this proceeding, APS utilized the prior 2019 depreciation study life analysis to develop curve retirements. Accordingly, the parameters used to develop the curve retirements in this proceeding were derived from an actuary analysis that was previously approved by the Commission in Decision No. 78317. For asset classes that utilize curve retirements, APS's retirement quantities originate from operational and field activity. Please see Dr Kateregga's Rebuttal Testimony for more discussion on curve retirements.

Q. DO YOU AGREE WITH THE TESTIMONY OF AARP WITNESS PAUL J/ ALVAREZ CONCERNING THE DEPRECIATION OF PALO VERDE GENERATING STATION (PVGS)?

A. No. The PVGS depreciation rates are appropriately determined through the 2024 depreciation study and should not be modified outside of the depreciation study results. Mr. Alvarez wrongly assumes that changes in PVGS depreciation rates are

[43] *See* 18 C.F.R. pt. 101, Electric Plant Instructions ¶ 10(D) (Uniform System of Accounts) ([T]he book cost shall be determined from the utility's records and if this cannot be done it shall be estimated".).

[44] 26 CFR § 1.168(i)-8.

[45] Edison Electric Institute & American Gas Association, *Introduction to Depreciation for Public Utilities and Other Industries* (Apr. 2013) at 37-39.

solely determined by the estimated life of the asset.[46] APS depreciation rates, including depreciation rates for PVGS, are developed through a well-established depreciation study process. Details of the 2024 depreciation study, inputs, and depreciation rates are provided in APS Witness Dr. Ronald E. White's Direct Testimony (REW-2DR). As discussed by Dr. White, the goal of depreciation accounting is to charge operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. Changes in PVGS depreciation rates are impacted by many factors including the prior operating license extension that occurred, expected future operating license extensions, and the accumulated reserve balance amortization periods, among other factors. Please see Dr Kateregga's Rebuttal Testimony for more discussion on depreciation of PVGS.

Q. WHAT IS THE KEY FACTOR DRIVING THE INCREASE IN DEPRECIATION RATES FOR THE PVGS IN THIS CASE?

A. When comparing the previously approved depreciation rates to the 2024-proposed depreciation rates in this rate case, the increase in PVGS depreciation expense is driven primarily by the treatment of the excess reserve in the prior case which has provided additional benefit to customers. In the prior rate case, the Commission ordered PVGS's excess reserves to be amortized over six years, which accelerated the return of those reserves to customers and reduced rates during that period. That accelerated treatment depleted the excess reserve identified in the 2019 depreciation study. APS has proposed to increase the depreciable life of PVGS in the 2024 depreciation study by 20-years in anticipation of being granted an operating license extension. While this increase in depreciable life reduces rates on a standalone basis, comparison to prior approved rates must reflect that customers

[46] AARP, Direct Testimony of Paul J. Alvarez (Mar. 2, 2026) (Alvarez Direct) at 38 (asserting APS's analysis relies on depreciating the Unit 2 purchase price through 2065 and that it "should" instead be depreciated through 2046), 42-43 (recalculating using a useful life through 2046 rather than 2065).

already received the benefit of the accelerated amortization of the 2019 excess reserves which is now fully depleted. Because Mr. Alvarez fails to account for the impact of the accelerated reserve amortization in prior rates, his proposal is inconsistent and should be rejected. Please see Dr Kateregga's rebuttal testimony for further discussion on depreciation of PVGS.

Q. RUCO WITNESS DUSTIN MADSEN AND MR. ALVAREZ SUGGEST THAT THE NORMALIZATION AND ANNUALIZATION PRO FORMA ADJUSTMENTS APS REQUESTS IN THIS RATE CASE ARE UNNECESSARY. DO YOU AGREE?[47]

A. No. Normalization and annualization adjustments represent well-established methodologies utilized in historical Test Year rate cases. Notwithstanding that APS is seeking approval to utilize a formula rate to adjust base rates on a going between rate cases, the rates established in this proceeding are still based on the traditional historical-test year framework. In this context, these methodologies have been consistently applied and accepted in APS's previous rate cases. Normalizing or annualizing historical test year costs allows various cost factors, such as escalation, de-escalation, inflation, or deflation, and other similar changes to be appropriately adjusted. Regardless of whether the FRAM is approved in this rate case, the Company's normalization adjustments are intended to reflect costs at levels reflected in a 2024 calendar-year Test Year. APS does not anticipate rates in this case becoming effective until late 2026. Accordingly, effective rates established solely on theTest Year actual-level basis would remain approximately 24-months out of date and would fail to include inflation and other increases experienced in 2025 and 2026. Recognizing the impacts of regulatory lag on APS's financial stability, the Commission has routinely accepted annualization, normalization,

[47] RUCO, Direct Testimony of Dustin Madsen, CPA, CDP, CRRA, CPA (CAN), CA (CAN) (Mar. 2, 2026) at 35-36; Alvarez Direct at 66-68.

PTYP additions, and other pro forma adjustments as a tool to mitigate the effects of lag. As such, the Test Year costs in this rate case should be adjusted for normalized or annualized factors consistent with long-standing practices.

Q. DO YOU AGREE WITH HOW MS. HIGGINS RECOMMENDS THAT APS CALCULATE RECONSTRUCTED COST NEW LESS DEPRECIATION (RCND) IN THEIR DIRECT TESTIMONY?

A. No. APS has a long, well-accepted practice of calculating RCND that has been approved by the Commission in prior APS rate cases (s*ee e.g.,* Decision No. 79293 at 434, Decision No. 78317 at 303, and Decision No. 76295). As discussed in my Direct Testimony, APS's RCND calculation is consistent with the Commission's regulation A.A.C. R14-2-103(A)(3)(n) that defines RCND as "[a]n amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments."[48] The Commission has recognized that "[t]he two most important guides or measures are the original cost...and their reproduction new value, each as of the end of the test year and each less depreciation."[49] Ms. Higgins' proposed recommendation is unusual,[50] and inconsistent with the Commission's regulations, prior rate cases, and Commission precedent, which does not in any way reflect consideration of scaling post-Test Year accumulated depreciation and accumulated deferred income taxes proportionality to the RCND rate base calculation. Because it is incompatible with the Commission's regulations, which only refer to using the historical Test Year

[48] A.A.C. R14-2-103(A)(3)(n).
[49] *Ariz. Corp. Comm'n vs. Ariz. Water Co.* (1959), 85 Ariz. 198, 355 P.2d 412.
[50] Higgins Direct at 24-25.

adjusted for appropriate pro forma adjustments, and inconsistent with prior approved APS calculations of RCND, Ms. Higgins' proposal should be rejected.

The proposed adjustment would also add unnecessary complexity to well-established RCND rate base calculations. The proposal would also need to consider APS's inclusion of accumulated depreciation as a reduction to PTYP, as described in the PTYP section above. Moreover, if adjusting RCND for scaled post-Test Year accumulated depreciation, this approach would be duplicative and double count the same depreciation effect – once through the PTYP reduction and again through an RCND specific adjustment. Also, it would be inappropriate to apply a stand-alone RCND adjustment to a single proforma component and would be inconsistent with the purpose and standard structure of the RCND application. Coupled with the inconsistency with Commission regulations and approved RCND calculations in prior APS rate cases, the needless complexity of Ms. Higgins' theoretical proposal for RCND calculations is a further reason the proposal should be rejected.

VII. CONCLUSION

Q. DO YOU HAVE ANY CLOSING REMARKS?

A. Yes. I have addressed a number of operating income and rate base adjustments proposed by Staff and various intervenors in this case – agreeing with some, and disagreeing with, or at times correcting, others. In each instance, my goal is to make the adjusted Test Year more representative of the period of time that rates will be in effect. I have introduced SFR Schedule A-1, which is attached to Mr. Moe's Rebuttal Testimony, as well as SFR Schedules B-1, B-2, C-1, C-2 and C-3, which are included as Attachments EAB-01RB through EAB-05RB to my Rebuttal Testimony. These SFR Schedules are updated to reflect the updated pro forma adjustments and represent an accurate basis upon which the Commission can establish just and reasonable rates.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Attachment EAB-01RB

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-1
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	Original Cost – Total Company: Unadjusted Test Year Ended 12/31/2024 (A)	Pro Forma (a) (B)	Adjusted Test Year Ended 12/31/2024 (C)	Original Cost – ACC: Unadjusted Test Year Ended 12/31/2024 (D)	Pro Forma (a) (E)	Adjusted Test Year Ended 12/31/2024 (F)	Line No.
1.	Gross utility plant in service	$ 27,536,653	$ 1,112,648	$ 28,649,301	$ 23,262,340	$ 1,006,609	$ 24,268,948	1.
2.	Less: Accumulated depreciation & amortization (b)	10,037,959	115,820	10,153,779	8,773,168	96,612	8,869,781	2.
3.	Net utility plant in service	17,498,694	996,828	18,495,522	14,489,172	909,996	15,399,168	3.
	Deductions:							
4.	Deferred income taxes	2,448,229	46,337	2,494,566	2,031,546	45,714	2,077,260	4.
5.	Deferred investment tax credits	172,659	-	172,659	170,500	-	170,500	5.
6.	Customer advances (b)	569,343	-	569,343	531,089	-	531,089	6.
7.	Customer deposits	42,198	-	42,198	42,198	-	42,198	7.
8.	Liabilities for pension benefits	116,104	-	116,104	114,652	-	114,652	8.
9.	Liability for asset retirements (b)	1,146,585	-	1,146,585	1,132,244	-	1,132,244	9.
10.	Other deferred credits	62,143	-	62,143	61,366	-	61,366	10.
11.	Coal mine reclamation (b)	171,483	-	171,483	169,338	-	169,338	11.
12.	Unrecognized tax benefits (b)	48,725	-	48,725	48,116	-	48,116	12.
13.	Operating lease liabilities (b)	1,634,802	-	1,634,802	1,615,745	-	1,615,745	13.
14.	Regulatory liabilities	1,670,796	-	1,670,796	1,644,800	-	1,644,800	14.
15.	Total deductions	8,083,067	46,337	8,129,405	7,561,593	45,714	7,607,307	15.
	Additions:							
16.	Regulatory assets	1,375,853	5,626	1,381,479	1,272,594	3,268	1,275,862	16.
17.	Other deferred debits	27,471	-	27,471	25,803	-	25,803	17.
18.	Nuclear Decommissioning trust (b)	1,282,845	-	1,282,845	1,281,690	-	1,281,690	18.
19.	Other special use funds (b)	374,155	-	374,155	373,818	-	373,818	19.
20.	Assets for pension and other postretirement benefits (b)	335,458	-	335,458	304,470	-	304,470	20.
21.	Operating lease right-of-use assets (b)	1,604,324	-	1,604,324	1,580,698	-	1,580,698	21.
22.	Allowance for working capital (c)	484,076	(13,385)	470,691	442,009	(12,149)	429,860	22.
23.	Total additions	5,484,182	(7,759)	5,476,423	5,281,083	(8,881)	5,272,202	23.
24.	Total rate base	$ 14,899,809	$ 942,732	$ 15,842,541	$ 12,208,661	$ 855,401	$ 13,064,062 (d)	24.

Supporting Schedules:
(a) B-2
(b) E-1
(c) B-5

Recap Schedules:
(d) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-1
SUMMARY OF ORIGINAL COST AND RCND RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	RCND Total Company: Unadjusted Test Year Ended 12/31/2024 (a) (d) (A)	Total Company: Pro Forma (a) (B)	Total Company: Adjusted Test Year Ended 12/31/2024 (a) (C)	ACC: Unadjusted Test Year Ended 12/31/2024 (a) (d) (D)	ACC: Pro Forma (a) (E)	ACC: Adjusted Test Year Ended 12/31/2024 (a) (d) (F)	Line No.
1.	Gross utility plant in service	$ 65,825,276	$ 1,112,648	$ 66,937,924	$ 55,607,700	$ 1,006,609	$ 56,614,309	1.
2.	Less: Accumulated depreciation & amortization	22,613,042	115,820	22,728,862	19,763,781	96,612	19,860,393	2.
3.	Net utility plant in service	43,212,234	996,828	44,209,062	35,843,919	909,996	36,753,915	3.
	Deductions:							
4.	Deferred income taxes	6,209,907	46,337	6,256,244	5,152,994	45,714	5,198,708	4.
5.	Deferred investment tax credits (b)	172,659	-	172,659	170,500	-	170,500	5.
6.	Customer advances (b)	569,343	-	569,343	531,089	-	531,089	6.
7.	Customer deposits	42,198	-	42,198	42,198	-	42,198	7.
8.	Liabilities for pension benefits	116,104	-	116,104	114,652	-	114,652	8.
9.	Liability for asset retirements (b)	1,146,585	-	1,146,585	1,132,244	-	1,132,244	9.
10.	Other deferred credits	62,143	-	62,143	61,366	-	61,366	10.
11.	Coal mine reclamation (b)	171,483	-	171,483	169,338	-	169,338	11.
12.	Unrecognized tax benefits (b)	48,725	-	48,725	48,116	-	48,116	12.
13.	Operating lease liabilities (b)	1,634,802	-	1,634,802	1,615,745	-	1,615,745	13.
14.	Regulatory liabilities	1,670,796	-	1,670,796	1,644,800	-	1,644,800	14.
15.	Total deductions	11,844,745	46,337	11,891,083	10,683,042	45,714	10,728,756	15.
	Additions:							
16.	Regulatory assets	1,375,853	5,626	1,381,479	1,272,594	3,268	1,275,862	16.
17.	Other deferred debits	27,471	-	27,471	25,803	-	25,803	17.
18.	Nuclear Decommissioning trust (b)	1,282,845	-	1,282,845	1,281,690	-	1,281,690	18.
19.	Other special use funds (b)	374,155	-	374,155	373,818	-	373,818	19.
20.	Assets for other postretirement benefits (b)	335,458	-	335,458	304,470	-	304,470	20.
21.	Operating lease right-of-use assets (b)	1,604,324	-	1,604,324	1,580,698	-	1,580,698	21.
22.	Allowance for working capital (c)	484,076	(13,385)	470,691	442,009	(12,149)	429,860	22.
23.	Total additions	5,484,182	(7,759)	5,476,423	5,281,082	(8,881)	5,272,201	23.
24.	Total rate base	$ 36,851,671	$ 942,732 (d)	$ 37,794,403 (d)	$ 30,441,959	$ 855,401 (d)	$ 31,297,360 (d) (e)	24.

Supporting Schedules:
(a) B-3
(b) E-1
(c) B-5
(d) B-4a

Recap Schedules:
(e) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(1) Actual at End of Test Year 2024 (a) Total Co. (A)	(1) Actual at End of Test Year 2024 (a) ACC (B)	(2) Non-Nuclear Generation Post-Test Year Plant Additions Total Co. (C)	(2) Non-Nuclear Generation Post-Test Year Plant Additions ACC (D)	(3) Nuclear Generation Post-Test Year Plant Additions Total Co. (E)	(3) Nuclear Generation Post-Test Year Plant Additions ACC (F)
1.	Gross Utility Plant in Service	$ 27,536,653	$ 23,262,340	$ 880,380	$ 879,588	$ 90,172	$ 90,091
2.	Less: Accumulated Depreciation & Amort.	10,037,959	8,773,168	235,599	235,387	48,632	48,588
3	Net Utility Plant in Service	17,498,694	14,489,172	644,781	644,201	41,540	41,503
4.	Less: Total Deductions	8,083,067	7,561,593	(6,329)	(6,324)	(3,844)	(3,841)
5.	Total Additions	5,484,182	5,281,083	-	-	-	-
6.	Total Rate Base	$ 14,899,809	$ 12,208,661	$ 651,111	$ 650,525	$ 45,385	$ 45,344
	PRO FORMA WITNESS:			TETLOW/BLANKENSHIP		TETLOW/BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]			1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)	

(1) Test Year Total Deductions and Total Additions are shown on Schedule B-1.

(2) Adjustment to Test Year rate base to include post-Test Year plant additions for Non-nuclear Generation with an in service date prior to December 31, 2025.

(3) Adjustment to Test Year rate base to include post-Test Year plant additions for Nuclear Generation with an in service date prior to December 31, 2025.

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(4) Distribution Post-Test Year Plant Additions		(5) IT/Facilities Post-Test Year Plant Additions		(6) Energy Storage Post-Test Year Plant Additions	
		Total Co. (G)	ACC (H)	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)
1.	Gross Utility Plant in Service	$ 262,800	$ 262,800	$ 215,401	$ 195,503	$ 240,318	$ 240,318
2.	Less: Accumulated Depreciation & Amort.	249,935	249,935	232,474	210,999	9,583	9,583
3	Net Utility Plant in Service	12,865	12,865	(17,073)	(15,496)	230,735	230,735
4.	Less: Total Deductions	3,363	3,363	6,639	6,025	24,376	24,376
5.	Total Additions	-	-	-	-	5,768	5,768
6.	Total Rate Base	$ 9,502	$ 9,502	$ (23,712)	$ (21,522)	$ 212,128	$ 212,128
	PRO FORMA WITNESS:	TETLOW/BLANKENSHIP		TETLOW/BLANKENSHIP		TETLOW/BLANKENSHIP/BAUER	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Functionalized on Distribution		1. Jurisdictional 2. Functionalized on Wages & Salaries		1. ACC Specific 2. Functionalized on Demand Production (Retail DEMPROD1; Schedule G-7 line 27)	

(4) Adjustment to Test Year rate base to include post-Test Year plant additions for Distribution with an in service date prior to December 31, 2025.

(5) Adjustment to Test Year rate base to include post-Test Year plant additions for IT/Facilities with an in service date prior to December 31, 2025.

(6) Adjustment to Test Year rate base to include post-Test Year Plant Additions for Energy Storage with an in service date prior to December 31, 2025.

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(7) Include West Phoenix Unit 4 Regulatory Disallowance		(8) Adjust Cash Working Capital for Cost of Service		(9) Include Cloud Computing	
		Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
1.	Gross Utility Plant in Service	$ (13,833)	$ (13,821)	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	(8,241)	(8,234)	-	-	-	-
3	Net Utility Plant in Service	(5,592)	(5,587)	-	-	-	-
4.	Less: Total Deductions	(1,382)	(1,381)	-	-	-	-
5.	Total Additions	-	-	(13,385)	(12,149)	25,649	23,279
6.	Total Rate Base	$ (4,210)	$ (4,206)	$ (13,385)	$ (12,149)	$ 25,649	$ 23,279
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)		1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Functionalized on Wages & Salaries	

(7) Adjustment to Test Year rate base to include the regulatory disallowance for West Phoenix CC Unit 4 as required by Decision Nos. 67744 and 69663.

(8) Adjustment to Cash Working Capital to reflect impacts of cost of service pro formas on the lead/lag study.

(9) Adjustment to rate base to reflect the impacts of Cloud Computing in alignment with NARUC's Cloud Computing Resolution.

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(10) Include ADIT Impact from NGS Amortization Disallowance		(11) Include Wildfire Mitigation O&M Cost Accumulation		(12) Include E3/E4 Customer Bill Payment Fees Deferral	
		Total Co. (S)	ACC (T)	Total Co. (U)	ACC (V)	Total Co. (W)	ACC (X)
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amort.	-	-	-	-	-	-
3	Net Utility Plant in Service	-	-	-	-	-	-
4.	Less: Total Deductions	(1,237)	(1,235)	-	-	-	-
5.	Total Additions	-	-	27,903	27,860	774	774
6.	Total Rate Base	$ 1,237	$ 1,235	$ 27,903	$ 27,860	$ 774	$ 774
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN; Schedule G-7 line 26)		1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN; G-7 line 26)		1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN; Schedule G-7 line 32)	

(10) Adjustment to Test Year rate base to remove 15% of Accumulated Deferred Income Taxes related to the regulatory asset for Navajo Generating Station (NGS) unrecovered plant costs from rate base consistent with Decision No. 78317.

(11) Adjustment to Test Year to include wildfire mitigation O&M expense accumulation.

(12) Adjustment to Test Year rate base to include the estimated E3/E4 customer bill payment fees deferral amount from January 1, 2025 through October 1, 2026 (estimated rate effective date).

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(13) Include Cholla Unrecovered Costs Net of Prospective Customer Rate Benefit		(14) Include Palo Verde Lease Buyback		(15) Include FERC Order 898 Implementation Impacts	
		Total Co. (Y)	ACC (Z)	Total Co. (AA)	ACC (AB)	Total Co. (AC)	ACC (AD)
1.	Gross Utility Plant in Service	$ (760,270)	$ (759,586)	$ 198,744	$ 198,565	$ -	$ (85,787)
2.	Less: Accumulated Depreciation & Amort.	(651,858)	(651,272)	-	-	-	1,929
3	Net Utility Plant in Service	(108,412)	(108,314)	198,744	198,565	-	(87,716)
4.	Less: Total Deductions	24,753	24,731	-	-	-	-
5.	Total Additions	(46,563)	(46,521)	-	-	-	-
6.	Total Rate Base	$ (179,728)	$ (179,566)	$ 198,744	$ 198,565	$ -	$ (87,716)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; G-7 line 17)		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; G-7 line 17)		1. Jurisdictional 2. Assigned using both Wages and Salaries less Transmission and Transmission	

(13) Include Cholla unrecovered costs, net of customer rate benefit in rate base.

(14) Adjustment to rate base for the PV Lease Buyback purchase of 2 of 3 leases on December 31, 2025. See Income Statement Proforma for adjustments associated with this plant purchase relating to depreciation and property tax expense.

(15) Adjustment to rate base for the impacts of FERC Order 898 as a result of the plant asset transfers between functional categories, thus impacting recovery. Represents the net transfers into/out of FERC/ACC jurisdiction.

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(16) Remove Buckeye Service Center From Rate Base		(17) Remove Navajo Coal Reclamation Regulatory Asset		Total Original Cost Rate Base Pro Forma Adjustments	
		Total Co. (AE)	ACC (AF)	Total Co. (AG)	ACC (AH)	(b) Total Co. (AI)	(b) ACC (AJ)
1.	Gross Utility Plant in Service	$ (1,064)	$ (1,064)	$ -	$ -	$ 1,112,648	$ 1,006,609
2.	Less: Accumulated Depreciation & Amort.	(304)	$ (304)	-	$ -	115,820	$ 96,612
3	Net Utility Plant in Service	(760)	(759)	-	-	996,828	909,996
4.	Less: Total Deductions	-	-	-	-	46,337	45,714
5.	Total Additions	-	-	(7,905)	(7,893)	(7,759)	(8,881)
6.	Total Rate Base	$ (760)	$ (759)	$ (7,905)	$ (7,893)	$ 942,732	$ 855,401
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP			
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Functionalized on Wages & Salaries less Transmission		1. Jurisdictional 2. Assigned to System Benefits (ERGYSYSBEN; G-7 line 26)			

(16) Remove Buckeye Service Center from plant in service at the end of the Test Year.

(17) Adjustment to Test Year rate base to remove Navajo Generating Station Coal Reclamation regulatory asset, as it will be fully amortized by rate effective date.

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE B-2
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	Adjusted at End of Test Year12/31/2024 (b) Total Co. *(AK)*	(b) ACC *(AL)*
1.	Gross Utility Plant in Service	$ 28,649,301	$ 24,268,948
2.	Less: Accumulated Depreciation & Amort.	10,153,779	8,869,781
3	Net Utility Plant in Service	18,495,522	15,399,168
4.	Less: Total Deductions	8,129,405	7,607,307
5.	Total Additions	5,476,423	5,272,202
6.	Total Rate Base	$ 15,842,541	$ 13,064,062

PRO FORMA WITNESS:

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: MOE]

Recap Schedules:
(b) B-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-1
INCOME STATEMENT
TOTAL COMPANY
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	Total Company Actual For The Test Year Ended 12/31/2024 (a) (A)	Proforma Adjustments (b) (B)	Test Year Results After Proforma Adjustments (c) (C)	Line No.
	Operating Revenues:				
1.	Revenues from Base Rates	$ 4,168,063	$ (11,319)	$ 4,156,744	1.
2.	Revenues from Surcharges	729,684	(729,684)	-	2.
3.	Other Electric Revenues	245,603	-	245,603	3.
4.	Total	5,143,350	(741,003)	4,402,347	4.
	Operating expenses:				
5.	Fuel and purchased power	1,843,345	(292,824)	1,550,521	5.
6.	Operations and maintenance	1,091,561	(237,212)	854,349	6.
7.	Depreciation and amortization	893,889	122,069	1,015,958	7.
8.	Income taxes	136,678	(120,309)	16,369	8.
9.	Taxes other than income taxes	258,913	17,628	276,541	9.
10.	Total	4,224,386	(510,648)	3,713,738	10.
11.	Operating income	918,964	(230,355)	688,609	11.
	Other income (deductions):				
12.	Income taxes	12,428	-	12,428	12.
13.	Allowance for equity funds used during construction	38,620	-	38,620	13.
14.	Other income	23,438	-	23,438	14.
15.	Other expense	(36,573)	-	(36,573)	15.
16.	Total	37,913	-	37,913	16.
17.	Income before interest deductions	956,877	(230,355)	726,522	17.
	Interest expense:				
18.	Interest charges	363,223	-	363,223	18.
19.	Allowance for borrowed funds used during construction	(48,270)	-	(48,270)	19.
20.	Total	314,953	-	314,953	20.
21.	Net income	$ 641,924	$ (230,355)	$ 411,569	21.

Supporting Schedules:
(a) E-2
(b) C-2

Recap Schedules:
(c) A-2

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-1
INCOME STATEMENT
ACC JURISDICTION
TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	ACC Jurisdiction: Actual For The Test Year Ended 12/31/2024 (A)	Proforma Adjustments (a) (B)	Test Year Results After Proforma Adjustments (C)	Line No.
	Operating Revenues:				
1.	Revenues from Base Rates	$4,154,548	$ (11,319)	$ 4,143,229	1.
2.	Revenues from Surcharges	728,949	(728,949)	-	2.
3.	Other Electric Revenues	131,877	-	131,877	3.
4.	Total	5,015,374	(740,268)	$ 4,275,107	4.
	Operating expenses:				
5.	Fuel and purchased power	1,621,169	(292,143)	1,329,026	5.
6.	Operations and maintenance	1,482,686	(232,956)	1,249,729	6.
7.	Depreciation and amortization	791,769	112,230	903,999	7.
8.	Income taxes	118,161	(118,464)	(303)	8.
9.	Taxes other than income taxes	217,166	16,359	233,525	9.
10.	Total	4,230,951	(514,975)	3,715,976	10.
11.	Operating income	784,424	(225,293)	559,130 (b)	11.
	Other income (deductions):				
12.	Income taxes	-	-	-	12.
13.	Allowance for equity funds used during construction	-	-	-	13.
14.	Other income	-	-	-	14.
15.	Other expense	-	-	-	15.
16.	Total	-	-	-	16.
17.	Income before interest deductions	784,424	(225,293)	559,130	17.
	Interest deductions (income):				
18.	Interest charges	-	-	-	18.
19.	Allowance for borrowed funds used during construction	-	-	-	19.
20.	Total	-	-	-	20.
21.	Net income	$ 784,424	$ (225,293)	$ 559,130	21.

Supporting Schedules:
(a) C-2

Recap Schedules:
(b) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(1) Non-Nuclear Generation Post-Test Year Plant Additions		(2) Nuclear Generation Post-Test Year Plant Additions		(3) Distribution Post-Test Year Plant Additions	
		Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
		(A)	(B)	(C)	(D)	(E)	(F)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	31,520	31,491	1,199	1,198	7,204	7,204
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	
13.	Other Taxes	3,931	3,927	472	471	3,990	3,990
14.	Total Other Operating Expense	35,451	35,419	1,671	1,670	11,194	11,194
15.	Operating Income Before Income Tax	(35,451)	(35,419)	(1,671)	(1,670)	(11,194)	(11,194)
16.	Interest Expense 2.03%	13,218	13,206	921	920	193	193
17.	Taxable Income	(48,668)	(48,624)	(2,592)	(2,590)	(11,387)	(11,387)
18.	Current Income Tax Rate - 24.72%	(12,031)	(12,020)	(641)	(640)	(2,815)	(2,815)
19.	Operating Income (line 15 minus line 18)	$ (23,420)	$ (23,399)	$ (1,030)	$ (1,029)	$ (8,379)	$ (8,379)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)		1. ACC Specific 2. Functionalized on Distribution	

(1) Adjustment to Test Year operations to include depreciation, property taxes, and interest expense and reduced income taxes associated with Non-nuclear Generation post-Test Year plant additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 2.

(2) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Nuclear Generation post-Test Year plant additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 3.

(3) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Distribution post-Test Year plant additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 4.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(4) IT/Facilities Post-Test Year Plant Additions Total Co. (G)	(4) IT/Facilities Post-Test Year Plant Additions ACC (H)	(5) Energy Storage Post-Test Year Plant Additions Total Co. (I)	(5) Energy Storage Post-Test Year Plant Additions ACC (J)	(6) Base Fuel and Purchased Power Costs Total Co. (K)	(6) Base Fuel and Purchased Power Costs ACC (L)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		20,587	18,686	8,315	8,315	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		3,212	2,915	740	740	-	-
14.	Total Other Operating Expense		23,799	21,601	9,055	9,055	-	-
15.	Operating Income Before Income Tax		(23,799)	(21,601)	(9,055)	(9,055)	-	-
16.	Interest Expense	2.03%	(481)	(437)	54,029	54,029	-	-
17.	Taxable Income		(23,318)	(21,164)	(63,084)	(63,084)	-	-
18.	Current Income Tax Rate -	24.72%	(5,764)	(5,232)	(15,594)	(15,594)	-	-
19.	Operating Income (line 15 minus line 18)		$ (18,035)	$ (16,369)	$ 6,540	$ 6,540	$ -	$ -

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

IT/Facilities Post-Test Year Plant Additions	Energy Storage Post-Test Year Plant Additions	Base Fuel and Purchased Power Costs
BLANKENSHIP	BLANKENSHIP/BAUER	MOE
1. Jurisdictional 2. Functionalize on Wages and Salaries.	1. ACC Specific 2. Functionalized on Demand Production (Retail DEMPROD1; Schedule G-7 line 27)	1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2; Schedule G-7 line 30)

(4) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with IT/Facilities post-Test Year plant additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 5.

(5) Adjustment to Test Year operations to include depreciation, interest expense, property taxes, Investment Tax Credit cost of service benefits, and reduced income tax expense associated with Energy Storage post-Test Year plant additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 6.

(6) Adjustment to Test Year operations to reflect the 2024 Test Year base fuel and purchased power ¢/kWh rate at adjusted Test Year consumption levels transferring into base rates.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(7) Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals Total Co. (M)	(7) ACC (N)	(8) Chemical O&M Total Co. (O)	(8) ACC (P)	(9) Normalize Weather Conditions Total Co. (Q)	(9) ACC (R)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ (143,876)	$ (143,876)
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	(143,876)	(143,876)
5.	Electric Fuel and Purchased Power Costs	219,904	219,904	-	-	(58,957)	(58,957)
6.	Oper Rev Less Fuel & Purch Pwr Costs	(219,904)	(219,904)	-	-	(84,919)	(84,919)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	-	-	-	-
15.	Operating Income Before Income Tax	(219,904)	(219,904)	-	-	(84,919)	(84,919)
16.	Interest Expense 2.03%	-	-	-	-	-	-
17.	Taxable Income	(219,904)	(219,904)	-	-	(84,919)	(84,919)
18.	Current Income Tax Rate - 24.72%	(54,360)	(54,360)	-	-	(20,992)	(20,992)
19.	Operating Income (line 15 minus line 18)	$ (165,544)	$ (165,544)	$ -	$ -	$ (63,927)	$ (63,927)

	(7)	(8)	(9)
PRO FORMA WITNESS:	MOE	MOE	HOBBICK
G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Assigned to Production - Energy (Retail ENERGY2_XAG1; Schedule G-7 line 31)	1. ACC Specific 2. Assigned to Production - Energy (Retail ENERGY2_XAG1; Schedule G-7 line 31)	1. ACC Specific 2. Revenues and Expenses are class specific.

(7) Adjustment to Test Year retail fuel and purchased power costs to account for Test Year retail PSA deferred expenses and non-cash mark-to-market accruals.

(8) Maintain base chemical rate at current base chemical rate of 0.0744¢/kWh that is reflected in the Test Year costs (costs that were not deferred).

(9) Adjustment to Test Year operating revenues to reflect normal weather conditions for the ten years ended December 31, 2024.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(10) Annualize Customer Levels Total Co. (S)	(10) Annualize Customer Levels ACC (T)	(11) Remove Power Supply Adjustor (PSA) Revenue & Deferred Fuel Amortization Total Co. (U)	(11) Remove Power Supply Adjustor (PSA) Revenue & Deferred Fuel Amortization ACC (V)	(12) Remove Test Year Regulatory Assessment Total Co. (W)	(12) Remove Test Year Regulatory Assessment ACC (X)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ 33,599	$ 33,599	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	(425,886)	(425,214)	(10,984)	(10,984)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	33,599	33,599	(425,886)	(425,214)	(10,984)	(10,984)
5.	Electric Fuel and Purchased Power Costs	13,806	13,806	(417,436)	(416,777)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	19,794	19,794	(8,450)	(8,437)	(10,984)	(10,984)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	(8,450)	(8,437)	(10,984)	(10,984)
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	(8,450)	(8,437)	(10,984)	(10,984)
				-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	(8,450)	(8,437)	(10,984)	(10,984)
15.	Operating Income Before Income Tax	19,794	19,794	-	0	-	-
16.	Interest Expense 2.03%	-	-	-	-	-	-
17.	Taxable Income	19,794	19,794	-	0	-	-
18.	Current Income Tax Rate - 24.72%	4,893	4,893	-	0	-	-
19.	Operating Income (line 15 minus line 18)	$ 14,901	$ 14,901	$ -	$ 0	$ -	$ -

PRO FORMA WITNESS:

HOBBICK

BLANKENSHIP

BLANKENSHIP

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

1. ACC Specific
2. Revenues and Expenses are class specific.

1. Jurisdictional
2. Revenues and Expenses are class specific.

1. ACC Specific
2. Revenues and Expenses are class specific.

(10) Adjustment to Test Year operating revenues to reflect the annualization of customer levels at December 31, 2024.

(11) Adjustment to Test Year operations to remove retail PSA revenue and deferred fuel amortization related to prior periods.

(12) Adjustment to Test Year operations to remove the Regulatory Assessment surcharges from operating revenues and expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(13) Remove Test Year Transmission Cost Adjustor (TCA) Total Co. (Y)	(13) ACC (Z)	(14) Transfer Test Year Lost Fixed Cost Recovery (LFCR) Total Co. (AA)	(14) ACC (AB)	(15) Transfer Test Year Environmental Improvement Surcharge (EIS) Total Co. (AC)	(15) ACC (AD)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(13,257)	(13,287)	(48,552)	(48,552)	(641)	(640)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(13,257)	(13,287)	(48,552)	(48,552)	(641)	(640)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(13,257)	(13,287)	(48,552)	(48,552)	(641)	(640)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(13,257)	(13,287)	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(13,257)	(13,287)	-	-	-	-
		-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(13,257)	(13,287)	-	-	-	-
15.	Operating Income Before Income Tax	-	-	(48,552)	(48,552)	(641)	(640)
16.	Interest Expense 2.03%	-	-	-	-	-	-
17.	Taxable Income	-	-	(48,552)	(48,552)	(641)	(640)
18.	Current Income Tax Rate - 24.72%	-	-	(12,002)	(12,002)	(159)	(158)
19.	Operating Income (line 15 minus line 18)	$ -	$ -	$ (36,550)	$ (36,550)	$ (483)	$ (482)

PRO FORMA WITNESS:

BLANKENSHIP

HOBBICK/BLANKENSHIP

HOBBICK/BLANKENSHIP

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

1. Jurisdictional
2. Revenues and Expenses are class specific.

1. ACC Specific
2. Revenues and Expenses are class specific.

1. Jurisdictional
2. Revenues and Expenses are class specific.

(13) Adjustment to Test Year operations to remove the TCA from operating revenues and expenses.

(14) Adjustment to Test Year operations to transfer LFCR to base rates.

(15) Adjustment to Test Year operations to reflect the elimination of the EIS pursuant to Decision No. 79293.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(16) Remove Demand Side Management Adjustment Clause (DSMAC) Revenue & Expense		(17) Remove Renewable Energy Adjustment Clause (REAC)		(18) Remove Test Year Tax Expense Adjustor Mechanism (TEAM I, II, & III)	
			Total Co.	ACC	Total Co.	ACC	Total Co.	ACC
			(AE)	*(AF)*	*(AG)*	*(AH)*	*(AI)*	*(AJ)*
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		(75,118)	(75,044)	(104,290)	(104,267)	176	176
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		(75,118)	(75,044)	(104,290)	(104,267)	176	176
5.	Electric Fuel and Purchased Power Costs		-	-	(42,114)	(42,104)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		(75,118)	(75,044)	(62,177)	(62,163)	176	176
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		(70,139)	(70,068)	(62,177)	(62,163)	176	176
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		(70,139)	(70,068)	(62,177)	(62,163)	176	176
			-	-	-	-	-	-
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		(70,139)	(70,068)	(62,177)	(62,163)	176	176
15.	Operating Income Before Income Tax		(4,980)	(4,976)	-	-	-	-
16.	Interest Expense	2.03%	-	-	-	-	-	-
17.	Taxable Income		(4,980)	(4,976)	-	-	-	-
18.	Current Income Tax Rate -	24.72%	(1,231)	(1,230)	-	-	-	-
19.	Operating Income (line 15 minus line 18)		$ (3,749)	$ (3,746)	$ -	$ -	$ -	$ -
	PRO FORMA WITNESS:		HOBBICK/BLANKENSHIP		BLANKENSHIP		HOBBICK/BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]		1. Jurisdictional 2. Revenues and Expenses are class specific.		1. Jurisdictional 2. Revenues and Expenses are class specific.		1. ACC Specific 2. Revenues and Expenses are class specific.	

(16) Adjustment to Test Year operations to remove revenues and expenses recovered through the DSMAC. The remaining operating income adjustment is necessary to reflect the authorized performance incentive.

(17) Adjustment to Test Year operations to remove the REAC from operating revenues.

(18) Adjustment to Test Year operations to annualize the TEAM adjustor that was moved to base revenues in Decision No. 78317. The TEAM mechanism was set to zero in Decision No. 78317.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(19) Court Resolution Surcharge (CRS) Total Co. (AK)	(19) Court Resolution Surcharge (CRS) ACC (AL)	(20) Base Revenue Annualization Total Co. (AM)	(20) Base Revenue Annualization ACC (AN)	(21) Include West Phoenix Unit 4 Regulatory Disallowance Total Co. (AO)	(21) Include West Phoenix Unit 4 Regulatory Disallowance ACC (AP)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ 98,958	$ 98,958	$ -	$ -
2.	Revenues from Surcharges		(51,130)	(51,137)	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		(51,130)	(51,137)	98,958	98,958	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		(51,130)	(51,137)	98,958	98,958	-	-
			-	-				
	Other Operating Expenses:		-	-				
7.	Operations Excluding Fuel Expense		(16,765)	(16,767)	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		(16,765)	(16,767)	-	-	-	-
			-	-				
10.	Depreciation and Amortization		-	-	-	-	(329)	(329)
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		(16,765)	(16,767)	-	-	(329)	(329)
15.	Operating Income Before Income Tax		(34,365)	(34,370)	98,958	98,958	329	329
16.	Interest Expense	2.03%	-	-	-	-	(85)	(85)
17.	Taxable Income		(34,365)	(34,370)	98,958	98,958	414	414
18.	Current Income Tax Rate -	24.72%	(8,495)	(8,496)	24,462	24,462	102	102
19.	Operating Income (line 15 minus line 18)		$ (25,870)	$ (25,874)	$ 74,496	$ 74,496	$ 227	$ 226

PRO FORMA WITNESS:

HOBBICK/BLANKENSHIP

HOBBICK

BLANKENSHIP

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

1. Jurisdictional
2. Revenues and Expenses are class specific.

1. ACC Specific
2. Direct assigned

1. Jurisdictional
2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)

(19) Adjustment to remove a portion of CRS revenues from the Test Year. After the rate case, the CRS rate will be limited to the historic portion to recover any remaining historic balance authorized in Decision No. 78979.

(20) Adjustment to Test Year base revenues to annualize the change in rates approved in Decision No. 79293 and implemented on March 8, 2024.

(21) Adjustment to Test Year operations to reflect amortization of regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant as required by previous Decision Nos. 67744 and 69663.

Supporting Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(22) Include Interest Expense on Customer Deposits		(23) Include Removal Costs Associated with the Saguaro Power Plant		(24) Amortize Limited Income Discount Accumulation	
		Total Co. (AQ)	ACC (AR)	Total Co. (AS)	ACC (AT)	Total Co. (AU)	ACC (AV)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	1,464	1,464	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	1,464	1,464	-	-	-	-
10.	Depreciation and Amortization	-	-	(288)	(288)	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	15,953	15,953
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	1,464	1,464	(288)	(288)	15,953	15,953
15.	Operating Income Before Income Tax	(1,464)	(1,464)	288	288	(15,953)	(15,953)
16.	Interest Expense 2.03%	-	-	-	-	-	-
17.	Taxable Income	(1,464)	(1,464)	288	288	(15,953)	(15,953)
18.	Current Income Tax Rate - 24.72%	(362)	(362)	71	71	(3,944)	(3,944)
19.	Operating Income (line 15 minus line 18)	$ (1,102)	$ (1,102)	$ 217	$ 217	$ (12,009)	$ (12,009)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		HOBBICK	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Assigned to Customer Accounts (CUSTDEP; Schedule G-7 line 40)		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)		1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN; Schedule G-7 line 32)	

(22) Adjustment to Test Year operations to include the operating income impact of interest on customer deposits using the January 2025 interest rate.

(23) Adjustment to Test Year operations to refund the amortization of the remaining cost of removal liability balance over a three (3) year period.

(24) Adjustment to Test Year operations to amortize the Limited Income discount accumulation approved in Decision Nos. 78317 and 79293 over a three (3) year period.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(25) Include & Annualize E-3/E-4 Customer Bill Payment Fees Deferral Amortization		(26) Adjust Depreciation Expense		(27) Annualize Payroll Expense	
			Total Co. (AW)	ACC (AX)	Total Co. (AY)	ACC (AZ)	Total Co. (BA)	ACC (BB)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		454	454	-	-	15,175	13,773
8.	Maintenance		-	-	-	-	2,472	2,244
9.	Subtotal		454	454	-	-	17,647	16,017
10.	Depreciation and Amortization		-	-	76,660	68,736	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		454	454	76,660	68,736	17,647	16,017
15.	Operating Income Before Income Tax		(454)	(454)	(76,660)	(68,736)	(17,647)	(16,017)
16.	Interest Expense	2.03%	-	-	-	-	-	-
17.	Taxable Income		(454)	(454)	(76,660)	(68,736)	(17,647)	(16,017)
18.	Current Income Tax Rate -	24.72%	(112)	(112)	(18,950)	(16,992)	(4,362)	(3,959)
19.	Operating Income (line 15 minus line 18)		$ (342)	$ (342)	$ (57,710)	$ (51,745)	$ (13,285)	$ (12,057)
	PRO FORMA WITNESS:		BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]		1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN; Schedule G-7 line 32)		1. Jurisdictional 2. Assigned to PT&D; General and Intangible functionalized on Wages & Salaries		1. Jurisdictional 2. Functionalized on Wages & Salaries	

(25) Adjustment to Test Year operations to reflect amortization for the E3/E4 customer bill payment fees deferral accepted in Decision Nos. 78317 and 79293 over a three (3) year period.

(26) Adjustment to Test Year operations to reflect updated depreciation expense for the 2024 Test Year based on data as of December 31, 2023.

(27) Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax, and non-retirement benefit expenses to April 2025 employee and wage levels.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(28) Normalize Employee Benefits Total Co. (BC)	(28) Normalize Employee Benefits ACC (BD)	(29) Remove Supplemental Excess Benefit Retirement Plan (SERP) Expense Total Co. (BE)	(29) Remove Supplemental Excess Benefit Retirement Plan (SERP) Expense ACC (BF)	(30) Remove Stock Compensation Total Co. (BG)	(30) Remove Stock Compensation ACC (BH)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	35,333	32,069	(6,891)	(6,255)	(21,814)	(19,799)
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	35,333	32,069	(6,891)	(6,255)	(21,814)	(19,799)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	35,333	32,069	(6,891)	(6,255)	(21,814)	(19,799)
15.	Operating Income Before Income Tax	(35,333)	(32,069)	6,891	6,255	21,814	19,799
16.	Interest Expense 2.03%	-	-	-	-	-	-
17.	Taxable Income	(35,333)	(32,069)	6,891	6,255	21,814	19,799
18.	Current Income Tax Rate - 24.72%	(8,734)	(7,928)	1,704	1,546	5,392	4,894
19.	Operating Income (line 15 minus line 18)	$ (26,599)	$ (24,142)	$ 5,188	$ 4,709	$ 16,422	$ 14,905

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

(28) Normalize Employee Benefits	(29) Remove Supplemental Excess Benefit Retirement Plan (SERP) Expense	(30) Remove Stock Compensation
BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
1. Jurisdictional	1. Jurisdictional	1. Jurisdictional
2. Functionalized on Wages & Salaries	2. Functionalized on Wages & Salaries	2. Functionalized on Wages & Salaries

(28) Adjustment to Test Year operations to reflect change in benefit expense to current year 2025 actuals.

(29) Adjustment to Test Year operations to remove Supplemental Excess Benefit Retirement Plan (SERP) Expense.

(30) Adjustment to Test Year operations to remove Stock Compensation expense.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(31) Include Active Union Medical Trust Interest Income and Realized Gains		(32) Remove 50% of Test Year Cash Incentive Expense		(33) Normalize Income Tax Expense/Interest Synchronization	
			Total Co. (BI)	ACC (BJ)	Total Co. (BK)	ACC (BL)	Total Co. (BM)	ACC (BN)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		(5,358)	(4,863)	(19,982)	(18,136)	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		(5,358)	(4,863)	(19,982)	(18,136)	-	-
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	(10,304)	(9,352)	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		(5,358)	(4,863)	(30,286)	(27,488)	-	-
15.	Operating Income Before Income Tax		5,358	4,863	30,286	27,488	-	-
16.	Interest Expense	2.03%	-	-	-	-	67,793	67,180
17.	Taxable Income		5,358	4,863	30,286	27,488	(67,793)	(67,180)
18.	Current Income Tax Rate -	24.72%	1,324	1,202	7,487	6,795	(16,758)	(16,607)
19.	Operating Income (line 15 minus line 18)		$ 4,033	$ 3,661	$ 22,799	$ 20,693	$ 16,758	$ 16,607
	PRO FORMA WITNESS:		BLANKENSHIP		BLANKENSHIP		BLANKENSHIP/BAUER	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]		1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Calculated as the weighted average of "Other Tax Items"	

(31) Adjustment to Test Year operations to include interest income and realized gain on investments in the Active Union Medical Trust Account.

(32) Adjustment to Test Year operations to reduce the cash incentive program, including payroll taxes, by a 50% reduction.

(33) Adjustment to Test Year operations for top down income tax true-ups consistent with prior decisions using Test Year rate base and composite cost of long-term debt. Tax true-ups are reflected as interest in this adjustment inclusive of Investment Tax Credit cost of service benefits.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(34) Annualize Property Tax Expense Total Co. (BO)	(34) Annualize Property Tax Expense ACC (BP)	(35) Remove & Annualize Property Tax Deferrals Amortization Total Co. (BQ)	(35) Remove & Annualize Property Tax Deferrals Amortization ACC (BR)	(36) Remove AutoPay Credit Total Co. (BS)	(36) Remove AutoPay Credit ACC (BT)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	(2,437)	(2,437)
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	(2,437)	(2,437)
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		5,731	4,759	3,876	3,876	-	-
14.	Total Other Operating Expense		5,731	4,759	3,876	3,876	(2,437)	(2,437)
15.	Operating Income Before Income Tax		(5,731)	(4,759)	(3,876)	(3,876)	2,437	2,437
16.	Interest Expense	2.03%	-	-	-	-	-	-
17.	Taxable Income		(5,731)	(4,759)	(3,876)	(3,876)	2,437	2,437
18.	Current Income Tax Rate -	24.72%	(1,417)	(1,177)	(958)	(958)	602	602
19.	Operating Income (line 15 minus line 18)		$ (4,314)	$ (3,583)	$ (2,918)	$ (2,918)	$ 1,834	$ 1,834

	(34) Annualize Property Tax Expense	(35) Remove & Annualize Property Tax Deferrals Amortization	(36) Remove AutoPay Credit
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	HOBBICK
G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Functionalized on PT&D	1. ACC Specific 2. Distribution Property Tax functionalized on Distribution and Generation Property Tax functionalized on Demand Production (Retail DEMPROD1; Schedule G-7 line 27)	1.ACC Specific 2.Revenues are class specific

(34) Adjustment to Test Year operations to annualize property taxes calculated using the anticipated 2025 tax assessment ratio and tax rate.

(35) Adjustment to remove the property tax deferral as accepted in Decision No. 76295 and annualize amortization of the property tax deferral as accepted in Decision No. 79293 over three (3) years.

(36) Adjustment to Test Year to remove the AutoPay discount provided in the 2024 Test Year as APS is proposing to eliminate this credit.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(37) Annualize Four Corners Coal Reclamation Costs		(38) Remove Navajo Generating Station Coal Reclamation Costs		(39) Adjust Cash Working Capital for Cost of Service	
			Total Co. (BU)	ACC (BV)	Total Co. (BW)	ACC (BX)	Total Co. (BY)	ACC (BZ)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		(5,049)	(5,041)	(2,978)	(2,974)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		5,049	5,041	2,978	2,974	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		-	-	-	-	-	-
15.	Operating Income Before Income Tax		5,049	5,041	2,978	2,974	-	-
16.	Interest Expense	2.03%	-	-	-	-	(272)	(247)
17.	Taxable Income		5,049	5,041	2,978	2,974	272	247
18.	Current Income Tax Rate -	24.72%	1,248	1,246	736	735	67	61
19.	Operating Income (line 15 minus line 18)		$ 3,801	$ 3,795	$ 2,242	$ 2,239	$ (67)	$ (61)

PRO FORMA WITNESS:

BLANKENSHIP

BLANKENSHIP

BLANKENSHIP

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

1. Jurisdictional
2. Assigned to System Benefits
(ERGSYSBEN; Schedule G-7 line 26)

1. Jurisdictional
2. Assigned to System Benefits
(ERGSYSBEN; Schedule G-7 line 26)

1. Jurisdictional
2. Functionalized on Wages & Salaries

(37) Adjustment to Test Year operations to reflect most recent Four Corners Power Plant coal reclamation study.

(38) Adjustment to remove the Test Year amortization currently being recovered in rates as a result of this balance being fully recovered as of the estimated rate effective date of October 2026.

(39) Adjustment to Test Year interest expense for cash working capital rate base pro forma adjustment.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(40) Normalize Nuclear Maintenance Expense Total Co. (CA)	(40) Normalize Nuclear Maintenance Expense ACC (CB)	(41) Normalize Fossil Maintenance Expense Total Co. (CC)	(41) Normalize Fossil Maintenance Expense ACC (CD)	(42) Annualize Sundance Maintenance Expense Accrual Total Co. (CE)	(42) Annualize Sundance Maintenance Expense Accrual ACC (CF)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	(659)	(658)	(8,778)	(8,764)	3,976	3,969
9.	Subtotal	(659)	(658)	(8,778)	(8,764)	3,976	3,969
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(659)	(658)	(8,778)	(8,764)	3,976	3,969
15.	Operating Income Before Income Tax	659	658	8,778	8,764	(3,976)	(3,969)
16.	Interest Expense 2.03%	-	-	-	-	-	-
17.	Taxable Income	659	658	8,778	8,764	(3,976)	(3,969)
18.	Current Income Tax Rate - 24.72%	163	163	2,170	2,166	(983)	(981)
19.	Operating Income (line 15 minus line 18)	$ 496	$ 495	$ 6,608	$ 6,597	$ (2,993)	$ (2,988)

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

(40) Normalize Nuclear Maintenance Expense	(41) Normalize Fossil Maintenance Expense	(42) Annualize Sundance Maintenance Expense Accrual
BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1; Schedule G-7 line 22)	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1; Schedule G-7 line 22)	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1; Schedule G-7 line 22)

(40) Adjustment to Test Year operations to reflect 3-year normalization of nuclear production maintenance expense.

(41) Adjustment to Test Year operations to reflect 6-year normalization of fossil production maintenance expense.

(42) Adjustment to Test Year operations to annualize the accrual of Sundance maintenance costs as authorized in Decision No. 69663 and accepted in Decision Nos. 78317 and 79293.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(43) Include Navajo Regulatory Asset Amortization Disallowance		(44) Include & Annualize Ocotillo Modernization Project (OMP) Deferral Amortization		(45) Include OMP Equity Return Disallowance	
			Total Co. (CG)	ACC (CH)	Total Co. (CI)	ACC (CJ)	Total Co. (CK)	ACC (CL)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		(1,441)	(1,439)	984	984	(4,052)	(4,052)
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		(1,441)	(1,439)	984	984	(4,052)	(4,052)
15.	Operating Income Before Income Tax		1,441	1,439	(984)	(984)	4,052	4,052
16.	Interest Expense	2.03%	-	-	-	-	-	-
17.	Taxable Income		1,441	1,439	(984)	(984)	4,052	4,052
18.	Current Income Tax Rate -	24.72%	356	356	(243)	(243)	1,002	1,002
19.	Operating Income (line 15 minus line 18)		$ 1,085	$ 1,083	$ (740)	$ (740)	$ 3,050	$ 3,050
	PRO FORMA WITNESS:		BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]		1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN; Schedule G-7 line 26)		1. ACC Specific 2. Assigned to Production - Demand (Retail DEMPROD1; Schedule G-7 line 27)		1. ACC Specific 2. Assigned to Production Demand (Retail DEMPROD1; Schedule G-7 line 27)	

(43) Adjustment to Test Year operations to record 15% disallowance of the annualized amortization expense related to the regulatory asset of Navajo Generating Station pursuant to Decision No. 78317.

(44) Adjustment to Test Year operations to annualize amortization of the OMP deferral authorized in Decision No. 78317 and accepted in Decision No. 79293.

(45) Adjustment to Test Year operations to reflect the disallowance of the OMP Deferral Equity Return pursuant to Decision No. 78317.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(46) Include Wildfire Mitigation O&M Cost Accumulation Amortization Total Co. (CM)	(46) ACC (CN)	(47) Annualize Four Corners SCR Deferral Amortization Total Co. (CO)	(47) ACC (CP)	(48) Normalize Wildfire Mitigation O&M Costs Total Co. (CQ)	(48) ACC (CR)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	11,377	11,377
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	11,377	11,377
10.	Depreciation and Amortization	5,581	5,572	(417)	(417)	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	5,581	5,572	(417)	(417)	11,377	11,377
15.	Operating Income Before Income Tax	(5,581)	(5,572)	417	417	(11,377)	(11,377)
16.	Interest Expense 2.03%	-	-	-	-	-	-
17.	Taxable Income	(5,581)	(5,572)	417	417	(11,377)	(11,377)
18.	Current Income Tax Rate - 24.72%	(1,380)	(1,377)	103	103	(2,812)	(2,812)
19.	Operating Income (line 15 minus line 18)	$ (4,201)	$ (4,195)	$ 314	$ 314	$ (8,565)	$ (8,565)

PRO FORMA WITNESS:

BLANKENSHIP

BLANKENSHIP

BLANKENSHIP

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

1. Jurisdictional
2. Assigned to System Benefits
(ERGSYSBEN; Schedule G-7 line 26)

1. Jurisdictional
2. Assigned to Production - Demand
(DEMPROD1; Schedule G-7 line 17)

1. ACC Specific
2. Functionalized on Distribution

(46) Adjustment to Test Year amortization expense to reflect the wildfire mitigation O&M cost accumulation amortization over five (5) years.

(47) Adjustment to the Test Year operations to annualize amortization of the Four Corners SCR deferral that was authorized in Decision Nos. 78317 and 79293.

(48) Adjustment to Test Year operations due to a significant increase in wildfire mitigation O&M expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(49) Adjust and Annualize Four Corners Inventory Total Co. (CS)	(49) ACC (CT)	(50) Remove Non-Recoverable Advertising Expense Total Co. (CU)	(50) ACC (CV)	(51) Remove Cholla Costs from Test Year Total Co. (CW)	(51) ACC (CX)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	(2,422)	(2,422)	(13,067)	(13,055)
8.	Maintenance	-	-	-	-	(7,112)	(7,106)
9.	Subtotal	-	-	(2,422)	(2,422)	(20,179)	(20,161)
10.	Depreciation and Amortization	1,361	1,360	-	-	(54,764)	(54,714)
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	(4,529)	(4,525)
14.	Total Other Operating Expense	1,361	1,360	(2,422)	(2,422)	(79,472)	(79,400)
15.	Operating Income Before Income Tax	(1,361)	(1,360)	2,422	2,422	79,472	79,400
16.	Interest Expense 2.03%	-	-	-	-	708	707
17.	Taxable Income	(1,361)	(1,360)	2,422	2,422	78,764	78,693
18.	Current Income Tax Rate - 24.72%	(337)	(336)	599	599	19,470	19,453
19.	Operating Income (line 15 minus line 18)	$ (1,025)	$ (1,024)	$ 1,823	$ 1,823	$ 60,001	$ 59,947

	(49)	(50)	(51)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)	1. ACC Specific 2. Functionalized on Wages & Salaries less Transmission	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1; Schedule G-7 line 17)

(49) Adjustment to Test Year operations to reflect the annualized level of amortization related to Four Corners material and supplies inventory as accepted in Decision Nos. 78317 and 79293.

(50) Adjustment to Test Year operations to remove non-recoverable advertising expense.

(51) Adjustment to Test Year operations to remove Cholla costs due to the cessation of plant operations.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(52) Remove Out of Period and Misc Items Total Co. (CY)	(52) Remove Out of Period and Misc Items ACC (CZ)	(53) Crisis Bill Commitment Request Total Co. (DA)	(53) Crisis Bill Commitment Request ACC (DB)	(54) Annualize TEAM Balancing Account Liability Amortization Total Co. (DC)	(54) Annualize TEAM Balancing Account Liability Amortization ACC (DD)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		(3,905)	(3,545)	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		(3,905)	(3,545)	-	-	-	-
10.	Depreciation and Amortization		-	-	-	-	(112)	(112)
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		(27,402)	(24,871)	2,500	2,500	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		(31,307)	(28,415)	2,500	2,500	(112)	(112)
15.	Operating Income Before Income Tax		31,307	28,415	(2,500)	(2,500)	112	112
16.	Interest Expense	2.03%	-	-	-	-	-	-
17.	Taxable Income		31,307	28,415	(2,500)	(2,500)	112	112
18.	Current Income Tax Rate -	24.72%	7,739	7,024	(618)	(618)	28	28
19.	Operating Income (line 15 minus line 18)		$ 23,568	$ 21,391	$ (1,882)	$ (1,882)	$ 84	$ 84

	(52) Remove Out of Period and Misc Items	(53) Crisis Bill Commitment Request	(54) Annualize TEAM Balancing Account Liability Amortization
PRO FORMA WITNESS:	BLANKENSHIP	HOBBICK	BLANKENSHIP
G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN; Schedule G-7 line 32)	1. ACC Specific 2. Assigned to Production Demand (Retail DEMPROD1; Schedule G-7 line 27)

(52) Adjustment to Test Year operations to remove Out of Period and Miscellaneous Items from the Test Year.

(53) Adjustment to Test Year operations to request the authorized level of Crisis Bill assistance funding (recorded below the line).

(54) Adjustment to Test Year operations to annualize amortization for the TEAM balancing account liability as accepted in Decision No. 79293.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(55) Annualize COVID Customer Relief Deferral Amortization		(56) Adjust for Palo Verde Lease Buyback Costs		(57) Include Removal Cost Associated with the Ocotillo Power Plant	
			Total Co. (DE)	ACC (DF)	Total Co. (DG)	ACC (DH)	Total Co. (DI)	ACC (DJ)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	(11,916)	(11,905)	-	-
9.	Subtotal		-	-	(11,916)	(11,905)	-	-
10.	Depreciation and Amortization		111	111	3,734	3,731	1,969	1,967
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	205	205	-	-
14.	Total Other Operating Expense		111	111	(7,976)	(7,969)	1,969	1,967
15.	Operating Income Before Income Tax		(111)	(111)	7,976	7,969	(1,969)	(1,967)
16.	Interest Expense	2.03%	-	-	-	-	-	-
17.	Taxable Income		(111)	(111)	7,976	7,969	(1,969)	(1,967)
18.	Current Income Tax Rate -	24.72%	(28)	(28)	1,972	1,970	(487)	(486)
19.	Operating Income (line 15 minus line 18)		$ (84)	$ (84)	$ 6,004	$ 5,999	$ (1,482)	$ (1,481)

PRO FORMA WITNESS:

	(55)	(56)	(57)
	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]	1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN; Schedule G-7 line 32)	1. Jurisdictional 2. Assigned to Production Demand (DEMPROD1; Schedule G-7 line 17)	1. Jursidictional 2. Assigned to Production Demand (DEMPROD1; Schedule G-7 line 17)

(55) Adjustment to Test Year operations to annualize amortization for the COVID Customer Relief account as accepted in Decision No. 79293 for three (3) years.

(56) Adjustment to 1) remove lease payment on two purchased leases from the Test Year, 2) add property tax expense related to these purchased leases, and 3) adjust the depreciation expense to reflect the annual cost of the newly acquired assets.

(57) Adjustment to Test Year Operations to include removal costs associated with the Ocotillo Power Plant.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description		(58) Include Amortization of Cholla Decommissioning Costs Total Co. (DK)	(58) ACC (DL)	(59) Remove Four Corners Units 1-3 Amortization Total Co. (DM)	(59) ACC (DN)	(60) Include Residual EIS Amortization Total Co. (DO)	(60) ACC (DP)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		-	-	-	-	-	-
10.	Depreciation and Amortization		24,247	24,225	(7,922)	(7,915)	316	316
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		24,247	24,225	(7,922)	(7,915)	316	316
15.	Operating Income Before Income Tax		(24,247)	(24,225)	7,922	7,915	(316)	(316)
16.	Interest Expense	2.03%	-	-	-	-	-	-
17.	Taxable Income		(24,247)	(24,225)	7,922	7,915	(316)	(316)
18.	Current Income Tax Rate -	24.72%	(5,994)	(5,988)	1,958	1,957	(78)	(78)
19.	Operating Income (line 15 minus line 18)		$ (18,253)	$ (18,237)	$ 5,964	$ 5,958	$ (238)	$ (238)

PRO FORMA WITNESS:

BLANKENSHIP

BLANKENSHIP

BLANKENSHIP

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

1. Jurisdictional
2. Assigned to Production Demand (DEMPROD1; Schedule G-7 line 17)

1. Jurisdictional
2. Assigned to Production Demand (DEMPROD1; Schedule G-7 line 17)

1. ACC Specific
2. Assigned to Production Demand (Retail DEMPROD1; Schedule G-7 line 27)

(58) Adjustment to Test Year operations to reflect amortization of closure and remediation of CCR disposal units at Cholla over 10 years.

(59) Adjust Test Year operations to remove the amortization of the SCE acquisition and Four Corners Units 1-3 costs that are fully recovered.

(60) Adjustment to Test Year operations to reflect amortization of the EIS residual balance over three (3) years. The EIS adjustor was eliminated in March 2024 with Decision 79293, resulting in this residual EIS balance.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(61) Adjust Cholla Unit 2 Cost of Removal Total Co. (DQ)	(61) Adjust Cholla Unit 2 Cost of Removal ACC (DR)	(62) Remove Buckeye Service Center Total Co. (DS)	(62) Remove Buckeye Service Center ACC (DT)	(63) Remove 50% Board of Director Fees Total Co. (DU)	(63) Remove 50% Board of Director Fees ACC (DV)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	14,767	14,754	(31)	(31)		
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	(1,718)	(1,560)
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	14,767	14,754	(31)	(31)	(1,718)	(1,560)
15.	Operating Income Before Income Tax	(14,767)	(14,754)	31	31	1,718	1,560
16.	Interest Expense 2.03%	-	-	-	-	-	-
17.	Taxable Income	(14,767)	(14,754)	31	31	1,718	1,560
18.	Current Income Tax Rate - 24.72%	(3,650)	(3,647)	8	8	425	386
19.	Operating Income (line 15 minus line 18)	$ (11,117)	$ (11,107)	$ 23	$ 23	$ 1,294	$ 1,174

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

(61) Adjust Cholla Unit 2 Cost of Removal	(62) Remove Buckeye Service Center	(63) Remove 50% Board of Director Fees
BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
1. Jursidictional 2. Assigned to Production Demand (DEMPROD1; Schedule G-7 line 17)	1. ACC Specific 2. Functionalized on Wages & Salaries less Transmission	1. Jurisdictional 2. Functionalized on Wages & Salaries

(61) Adjust Test Year operations to increase amount of removal costs to be recovered through June 2033.

(62) Adjust Test Year operations to remove Buckeye Service Center Depreciation.

(63) Remove 50% of Board of Director Expenses from Test Year.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-2
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	(64) Remove 50% D&O Insurance Total Co. (DW)	(64) Remove 50% D&O Insurance ACC (DX)	(65) Include Amortization of Cholla Unrecovered Cost and Prospective Customer Rate Benefit Total Co. (DY)	(65) Include Amortization of Cholla Unrecovered Cost and Prospective Customer Rate Benefit ACC (DZ)	Total Income Statement Adjustments (a) Total Co. (EA)	Total Income Statement Adjustments (a) ACC (EB)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ (11,319)	$ (11,319)
2.	Revenues from Surcharges	-	-	-	-	$ (729,684)	$ (728,949)
3.	Other Electric Revenues	-	-	-	-	$ -	$ -
4.	Total Electric Operating Revenues	-	-	-	-	(741,003)	$ (740,268)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	(292,824)	$ (292,143)
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	(448,179)	$ (448,125)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	(193,669)	$ (192,904)
8.	Maintenance	-	-	-	-	(22,017)	$ (22,219)
9.	Subtotal	-	-	-	-	(215,686)	$ (215,123)
10.	Depreciation and Amortization			(7,132)	(7,125)	122,069	$ 112,230
11.	Amortization of Gain	-	-	-	-	-	$ -
12.	Administrative and General	(555)	(504)	-	-	(21,526)	$ (17,833)
13.	Other Taxes	-	-	-	-	17,628	$ 16,359
14.	Total Other Operating Expense	(555)	(504)	(7,132)	(7,125)	(97,515)	$ (104,367)
15.	Operating Income Before Income Tax	555	504	7,132	7,125	(350,664)	$ (343,758)
16.	Interest Expense 2.03%	-	-	-	-	136,024	$ 135,466
17.	Taxable Income	555	504	7,132	7,125	(486,688)	$ (479,224)
18.	Current Income Tax Rate - 24.72%	137	125	1,763	1,761	(120,309)	$ (118,464)
19.	Operating Income (line 15 minus line 18)	$ 418	$ 379	$ 5,369	$ 5,364	$ (230,355)	$ (225,293)

PRO FORMA WITNESS:

G-7 FUNCTIONALIZATION OF PRO FORMA AND ALLOCATION FACTOR: [WITNESS: MOE]

BLANKENSHIP
1. Jurisdictional
2. Functionalized on Wages & Salaries

BLANKENSHIP
1. Jurisdictional
2. Assigned to Production Demand (DEMPROD1; Schedule G-7 line 17)

(64) Remove 50% D&O (Director and Officer) insurance premium expense from the Test Year.

(65) Adjustment to Test Year operations to reflect amortization of Cholla Unrecovered Costs and Prospective Customer Rate Benefit over 10 years.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE C-3
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR
TOTAL COMPANY
TEST YEAR ENDED DECEMBER 31, 2024

Line No.	Description		2024 Percentage of Incremental Gross Revenues	Line No.
1.	Gross Revenue		100%	1.
2.	Less uncollectible revenue		0.53%	2.
3.	Taxable revenue as a percent		99.47%	3.
4.	Federal Income Taxes*		20.89%	4.
5.	State Income Taxes Net of Federal Tax Benefit		3.72%	5.
6.	Total Tax Percentage**		24.61%	6.
7.	Tax Factor	*Line 3 - Line 6*	74.86%	7.
8.	Gross Revenue Conversion Factor	*(1 / Line 7) * 100*	1.3358	8.

* Federal Income Taxes (line 4) is calculated using the Federal Statutory Rate of 21% multiplied by Taxable Revenue as a percent (line 3)

** 2024 Estimated Composite tax rate utilized to derive income tax expense is 24.72%

Supporting Schedules:
N/A

Recap Schedules:
(a) A-1

Note: There may be variances in displayed calues due to rounding.

REBUTTAL TESTIMONY OF JESSICA E. HOBBICK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-25-0105

April 3, 2026

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SFR Schedule H-1 ..... Attachment JEH-01RB
SFR Schedule H-2 ..... Attachment JEH-02RB
FRAM Plan of Administration (Clean) ..... Attachment JEH-03RB
REAC Plan of Administration (Redline) ..... Attachment JEH-04RB

REAC Plan of Administration (Clean) ..... Attachment JEH-05RB
Service Schedule 3 (Redline) ..... Attachment JEH-06RB
Service Schedule 3 (Clean) ..... Attachment JEH-07RB
Service Schedule 1 (Redline) ..... Attachment JEH-08RB
Service Schedule 1 (Clean) ..... Attachment JEH-09RB
Response to Chairman Myers Letter dated October 1, 2025 ..... Attachment JEH-10RB
Response to Chairman Myers Letter dated December 18, 2025 .... Attachment JEH-11RB

REBUTTAL TESTIMONY OF JESSICA E. HOBBICK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-25-0105)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Jessica E. Hobbick. I am the Vice President of Rates and Regulatory for Arizona Public Service Company (APS or Company). I have oversight of the Load Research, Revenue Requirement, Rate Design, Rate Administration, and State Regulatory Strategy and Compliance teams. My business address is 400 N. 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my Rebuttal Testimony is to provide updated customer bill impacts aligned with the Rebuttal revenue requirement and to address assertions and recommendations related to APS's Formula Rate Adjustment Mechanism (FRAM). Where appropriate, my Rebuttal Testimony proposes adjustments that align with intervenor positions. My Rebuttal Testimony also addresses Residential and General Service rate design, APS's Service Schedules, and Limited Income program proposals, and responds to parties' requests related to the Alternative Generation (AG-X) Rate Rider and customer communications.

I do not address every detail related to the Utilities Division Staff (Staff) of the Arizona Corporation Commission (Commission) and intervenor recommendations, and it should not be interpreted that I agree with any of their positions unless specifically stated in my testimony.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In my Rebuttal Testimony I provide revised net bill impacts reflective of the updated Rebuttal revenue requirement and I address intervenor positions on revenue allocation and a number of Residential and General Service rate design proposals. I respond to proposals related to the Company's Limited Income Program and customer communications as well as various pro forma adjustments to the 12-month period ending December 31, 2024 (Test Year) revenues. I will also discuss proposed modifications to Service Schedules and Adjustment Mechanisms.

Lastly, my Rebuttal Testimony discusses some proposed modifications to the FRAM targeted at enabling a 2026 initial FRAM test year with a 2027 filing. These modifications are also aimed at preserving the 120-day filing and stakeholder process outlined in my Direct Testimony and supported by the Commission's Policy Statement Regarding Formula Rate (Commission's Policy Statement),[1] but modified to address recommendations from intervening parties. If both of these FRAM timing needs can be achieved, then it is reasonable for the FRAM to be modified as follows: (1) an increase in the FRAM deadband from +/-20 basis points (bps) to +/-40 bps, (2) a reduction from the 12-months of proposed projected plant to six-months of post-Test Year plant (PTYP), (3) an agreement to provide quarterly reporting of capital expenses, (4) elimination of the System Reliability Benefit (SRB) and Tax Expense Adjustor Mechanism (TEAM) as stand-alone adjustor mechanisms, and (5) eliminating the interim rate adjustment and instead having the annual FRAM rate change take effect with cycle one bills following the conclusion of the challenge period at which time the adjustment is approved. Collectively, these proposed modifications to APS's FRAM represent a package

[1] Decision No. 79647 (Dec. 31, 2024) at Attachment A (Commission's Policy Statement).

of changes that achieve a just and reasonable outcome for customers and the Company.

III. REVENUE ALLOCATION AND CUSTOMER BILL IMPACTS

Q. PLEASE DESCRIBE THE NET IMPACT THAT RESULTS FROM REBUTTAL UPDATES MADE.

A. As is customary in Rebuttal Testimony, updates are made to ensure the revenue requirement reflects updated actual expenses including refreshing PTYP projects that went into service during the designated period. These adjustments increase the revenue deficiency in the APS's 2025 Rate Case Application (Application), modifying the original $579.5 million net increase after adjustor transfers, or 13.99%, to $611.3 million, or 14.75%. The adjustments are largely driven by the inclusion of two new generation facilities that APS witness Jacob Tetlow discusses in his Rebuttal Testimony, the Ironwood Solar and Sundance Expansion projects.

Additionally, Standard Filing Requirement Schedule (SFR) H-1 now shows an overall residential net increase of 15.36% (*see* Attachment JEH-01RB).

Q. DID PARTIES SUPPORT THE REVENUE ALLOCATION METHODOLOGY PROPOSED BY THE COMPANY?

A. Several parties did not oppose the proposed allocation, while only a couple offered testimony objecting to the method used. Walmart Inc. (Walmart) witness Dr. Jaime McGovern does not object to the proposed revenue allocation methodology[2] and Arizona Association of School Business Officials, Arizona School Administrators, and Arizona School Boards Association (collectively, Arizona School Associations or School Groups) witness Travis Sarver alleged that their class

[2] Walmart, Direct Testimony of Jaime McGovern, Ph.D. (Mar. 18, 2026) (McGovern Direct-Rate Design) at 6-8.

received the sixth highest allocation among General Service classes.[3] SFR H-2 demonstrates that both the medium and large GS-Schools rate classes received a proposed allocation level of approximately 3% below the system average (*see* Attachment JEH-02RB). Other General Service rate classes received a smaller amount, because current rates achieve a larger portion of the cost to serve their respective rate classes. The Arizona Large Customer Group (AZLCG) and Freeport Minerals Corporation (Freeport) witness Jeffry Pollock states that the Commission should reject APS's proposed class revenue allocation because the allocation has an arbitrary and limited application of gradualism and claims that no class should receive an increase higher than 1.5 times the system average.[4]

Q. DOES THE COMPANY AGREE THAT ALL CUSTOMER CLASSES SHOULD RECEIVE AN INCREASE OF NO HIGHER THAN 1.5 TIMES THE SYSTEM AVERAGE?

A. No, not currently. Under ideal circumstances, having the ability to limit increases to all customer classes is always the desire of the Company. However, limiting the increase applied to larger General Service classes, who require a larger increase to recover the cost of serving them, would result in other residential and smaller business rate classes subsidizing a portion of these costs. Mr. Pollock also claims that APS incorrectly portrays the impact of the proposed increase by including embedded Power Supply Adjustor (PSA) costs in the base rate percentage.[5] Mr. Pollock, however, confuses the PSA with the embedded component of Base Fuel. He attempts to remove the Base Fuel portion of rates from the denominator but includes the Base Fuel increase in his numerator to demonstrate the increase on

[3] School Groups, Direct Testimony of Travis Sarver (Mar. 18, 2026) (Sarver Direct) at 13.

[4] AZLCG and Freeport, Direct Testimony of Jeffry Pollock (Mar. 18, 2026) (Pollock Direct) at 38-42.

[5] *Id*. at 37-38.

customer classes. This approach artificially reduces total base rates, which artificially inflates the percentage of increase.

IV. FRAM MECHANICS

Q. ARE THERE REASONS THAT FORMULA RATES MAY DIFFER ACROSS UTILITIES AND JURISDICTIONS?

A. There are reasons that different utilities may have unique needs that their formula rates are designed to accommodate. These can be dependent on certain policy goals utilities and regulators are aiming to achieve, or circumstances specific to one utility or region. As an example, Phoenix is ranked second in the nation for data center development,[6] so a formula that incorporates a method of class level cost allocation to address annual growth is appropriate where this may not apply to other utilities.

Other parties recognize these differences. For example, Sierra Club witness Melissa Whited offers that each utility formula rate plan should be evaluated on its own merits.[7] Staff witness Ralph Smith acknowledges that even the Federal Energy Regulatory Commission (FERC) formulas adopted by APS, Tucson Electric Power Company (TEP), and UNS Electric (UNSe) are not identical.[8] Mr. Smith opines that the FERC Midcontinent Independent System Operator (MISO) protocols are a good starting point, but that APS should conform to Arizona requirements and the state's unique regulatory environment.[9] It should also be noted that APS and

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[6] Russ Wiles, *Here's why metro Phoenix is now the biggest data center hub in the western US,* Arizona Republic, Mar. 4, 2024, https://www.azcentral.com/story/money/business/2024/03/04/metro-phoenix-now-second-biggest-data-center-hub-united-states/72804095007/?gnt-cfr=1&gca-cat=p&gca-uir=true&gca-epti=z114031e1199xxv114031d--45--b--45--&gca-ft=183&gca-ds=sophi

[7] Sierra Club, Direct Testimony of Melissa Whited (Mar. 18, 2026) (Whited Direct) at 9.

[8] Staff, Direct Testimony of Ralph C. Smith (Mar. 18, 2026) (Smith Direct-Rate Design) at 31.

[9] *Id.* at 31-32.

UNS Gas, Inc (UNSg) differ in a variety of material ways; such as size, differing service territories, services offered, and rates of relative growth. These differences, particularly those like growth rates that directly impact the degree to which regulatory lag impacts business operations, should be considered when comparing formula rates for each utility. Despite these differences, however, there is still useful information that can be derived from retail formula rate plans that have been approved for other utilities in Arizona, such as UNSg.

Q. DOES THE COMPANY PROPOSE ANY MODIFICATION TO THE USE OF 20 BPS AS THE DEADBAND RANGE FOR THE FRAM?

A. Yes. The Company proposes to modify the FRAM deadband range from 20 bps, as outlined in the Commission's Policy Statement to 40 bps to align more closely with testimony from Mr. Smith and Federal Executive Agencies (FEA) witness Christopher C. Walters, who both support a deadband of 50 bps. [10] Several other parties make recommendations on this topic. Local Unions of the International Brotherhood of Electrical Workers (IBEW) witness Dennis Carpenter supports the Company's original formula rate proposal arguing that a 20 bps deadband protects ratepayers,[11] while Residential Utility Consumer Office (RUCO) witness Dustin Madsen supports a wider deadband on the basis that a narrower range allows for more frequent true ups.[12]

A deadband of 40 bps balances the objective to mitigate regulatory lag through annual adjustments that avoid the accumulation of under-collected costs, which could ultimately result in a larger adjustment in a subsequent year, while also

[10] Commission's Policy Statement at Attachment A (2.c.); Smith Direct-Rate Design at 45-46; FEA, Direct Testimony of Christopher C. Walters (Mar. 2, 2026) at 8.
[11] IBEW, Direct Testimony of Dennis Carpenter (Mar. 2, 2026) (Carpenter Direct) at 9.
[12] RUCO, Direct Testimony of Dustin Madsen, CPA, CDP, CRRA, CPA (CAN), CA (CAN) (Mar. 2, 2026) (Madsen Direct) at 22-23.

maintaining smaller annual rate adjustments. This modification to the Company's FRAM proposal is part of a package of changes APS is making in this Rebuttal Testimony.

Q. HOW DO YOU RESPOND TO DR. MCGOVERN'S CONCERN THAT APS'S DEADBAND PROPOSAL SHIFTS THE BALANCE OF RISKS TO THE COMPANY'S CUSTOMERS?

A. In addition to arguing that APS's originally proposed +/- 20 bps deadband is too narrow, Dr. McGovern argues and that it protects downside earnings while limiting meaningful downside risk to shareholders, guaranteeing upward rate adjustments.[13] This perspective fails to recognize that the Company's deadband proposal is symmetric. Thus, the adjustment would reset upward if a 40-bps deficiency existed, but it would also adjust downward and benefit customers if a 40 bps surplus existed. As such, there is no guarantee of upward rate adjustments as suggested, or a shifting of risk. With respect to both issues, APS's updated +/- 40 bps proposal helps mitigate intervenor and Staff concerns.

Q. WHAT IS YOUR POSITION ON THE ASYMMETRIC DEADBAND PROPOSED BY AZLCG WITNESS BILLIE S. LACONTE AND MR. MADSEN?

A. Both parties propose an asymmetric +50/-80 bps deadband but do not support that recommendation with an example of a utility formula that operates under such criteria. I evaluated retail formulas in other jurisdictions and could not find one that included an asymmetric deadband construct. Further, Ms. LaConte and Mr. Madsen claim that the deadband should be asymmetric because the Company's proposal would incentivize a utility to increase capital spending. However, allowing a smaller threshold for downward adjustments, and a larger threshold for

[13] Walmart, Direct Testimony of Jaime McGovern, Ph.D. (Mar. 2, 2026) (McGovern Direct) Direct at 13-14.

upward adjustments, means that a deeper deficiency would be required before the utility could adjust rates to recover costs. The result is less progress in addressing regulatory lag and larger rate adjustments when the FRAM rate qualifies for a reset.

AZLCG and RUCO's argument also fails to recognize that, as discussed by APS witnesses Theodore N. Geisler and Chris R. Bauer, the same incentives to control costs that exist today would continue to exist if the FRAM were adopted. The FRAM doesn't expand the types of costs that would be recovered, nor does it change criteria used in determining whether such costs were prudently incurred. It simply adopts a structure where those same costs and revenues can be evaluated annually and rates aligned, whether an increase or a reduction is appropriate, to reduce the significant lag that exists under the traditional rate case structure.

Finally, APS will provide annual filings with audited financial results, among other information. This ensures that the Commission and interested stakeholders can review all investments and expenses each and every year without waiting multiple years until a general rate case filing occurs. This more frequent review allows for more scrutiny and transparency than traditional general rate cases, which focus on evaluating Test Year financial information only once in between lengthy, multi-year general rate cases.

Q. HOW DO YOU RESPOND TO AARP WITNESS PAUL J. ALVAREZ'S PROPOSAL FOR A "STANDARD DEVIATION" DEADBAND RESULTING IN A +/- 248 BASIS POINT RANGE?

A. First, I am not aware of any North American regulated utilities with formula rates operating under a deadband of this scale, nor does Mr. Alvarez cite any. In practice, this would mean that APS's actual earned return would need to fall a full 2.48% outside of the authorized return on equity (ROE) determined in this proceeding in

order to adjust rates up or down. Even more so than as discussed in intervenor arguments for wider deadbands elsewhere, this 248 bps deadband range would completely fail to offer any meaningful reductions in regulatory lag, whereby significant volumes of prudent investments and expenses would go unrecovered in rates for years at a time. Moreover, in the event the mechanism was triggered, a 248 bps deadband would result in significant rate adjustments as part of FRAM resets. Customers would experience none of the rate gradualism benefits that formula rates are intended to provide with AARP's proposal. For these and other reasons, this proposal should be rejected.

Q. PLEASE ADDRESS MR. MADSEN'S OPPOSITION TO INCLUDING THE RETURN ON THE FAIR VALUE INCREMENT (FVI) IN THE FRAM.

A. Mr. Madsen claims that the FVI should not be considered in the FRAM ROE evaluation each year on the basis that it does not represent 'real costs.' The Company is not proposing to simply add the return on the FVI to the ROE to establish the earnings test threshold. Instead, the same method of acknowledging FVI approved in the most recent rate case in the annual Lost Fixed Cost Recovery (LFCR) mechanism earnings test filing will be used. Under this approach, the dollar amount of approved FVI is converted to bps of adjusted ROE and illustrated in the calculation of the weighted average cost of capital (WACC). Not performing this adjustment would cause annual revenues that include an approved FVI to inadvertently exceed the earnings test threshold by not recognizing that rates were designed reflective of that portion of the revenue requirement.

Q. DO YOU AGREE WITH THE POSITION OF INTERVENING PARTIES ON THE INCLUSION OF PROJECTED PLANT IN THE FRAM?

A. The Company has carefully considered concerns expressed by both Mr. Madsen and Dr. McGovern that these costs would be borne by customers sooner than they

should be, or that customers are pre-paying for speculative growth that may not materialize.

First, the risk that other customers would be paying for speculative growth is mitigated by the minimum bill thresholds that exist within the tariff and the Electric Supply Agreements (ESA) APS requires for large, high load factor customers to execute. These requirements ensure that customers who require a high level of energy pay for those costs irrespective of whether they consume the energy.[14] Mr. Tetlow and Mr. Bauer discuss these requirements in more detail in their Rebuttal Testimonies.

Next, Ms. LaConte says that PTYP should not exist in the formula because it adds complexity and that a fully auditable historic test year should be used instead. Yet if one objective of a formula rate is to reduce regulatory lag, then allowing for projected plant is proper. This ensures that the timing of cost recovery aligns more closely with the timing of those assets providing benefit to customers. Keep in mind that the Company begins investing in those facilities sometimes years before they are placed in service, so there is still an inherent amount of lag between the costs being incurred and recovered. It's also important to note that the FRAM is based on fully audited annual financial information, just like a test year in a general rate case proceeding that utilizes a calendar test year. Moreover, there are significantly fewer pro forma adjustments under a formula rate because the test year is not being modified to represent a typical year as is necessary when setting rates in a traditional general rate case. I will discuss later in my Rebuttal Testimony an adjustment to the FRAM plan of administration (POA) related to the amount of

[14] AZLCG, Direct Testimony of Billie S. LaConte (Mar. 2, 2026) (LaConte Direct) at 18.

projected plant proposed for inclusion in the annual filing, which is being proposed as part of a package of FRAM changes APS is making in this Rebuttal Testimony.

Q. PLEASE RESPOND TO FEA WITNESS MICHAEL P. GORMAN'S DISCUSSION ON THE COST OF SERVICE METHODOLOGY IN RELATION TO THE FRAM.

A. Mr. Gorman appears to misunderstand the FRAM methodology. First, he states that the proposed FRAM allocation methodology is unreasonable because it will be based on the cost of service study (COSS) approved in the last rate case and will not be based on current costs.[15] However, the Company's proposal is to update the COSS annually with each FRAM filing and to use a 12-month historical test year, which reflects actual, verified expenses and costs closely contemporaneous to when FRAM resets would take effect. As such, Mr. Gorman's arguments related to the FRAM allocation methodology are misplaced.[16] Sales growth forecasts for any subsequent year are irrelevant to the Test Year period, as sales growth will be captured in the FRAM filing and rate adjustment in which the sales growth actually occurs. In addition, in the event of a base rate update that results from a rate case proceeding, the FRAM will capture this base rate revenue growth through the revenue annualization pro forma that is referenced in the FRAM POA.

Q. PLEASE RESPOND TO INTERVENOR ADJUSTMENT MECHANISM RECOMMENDATIONS IF THE FRAM IS APPROVED.

A. Several parties acknowledge the benefit of retaining separate PSA and Transmission Cost Adjustment (TCA) mechanisms should the FRAM be adopted.[17] Some intervenors suggest that all other adjustment mechanisms could

[15] FEA, Direct Testimony of Michael P. Gorman (Mar. 2, 2026) (Gorman Direct) at 11-12.

[16] *Id.* at 11-12.

[17] *See* Smith Direct-Rate Design at 11, 19-21; LaConte Direct at 27; *see also* Gorman Direct at 13-14 (no opposition to maintaining the PSA).

be eliminated with the implementation of the FRAM. However, this perspective ignores that each adjustment mechanism has its own distinct schedules and POA to define the scope of costs that can be recovered, the method of calculating each rate, and the process for formal review and approval to ensure transparency and a thorough review process. The Commission has recognized the need to retain separate mechanisms where appropriate. In fact, in Decision No. 79293, APS proposed to incorporate a portion of the costs recovered in the Demand Side Management Adjustment Charge (DSMAC) into base rates. The Commission instead ordered APS to move all base rate recovery back into the adjustment mechanism to ensure customers were made aware of specific costs to fund those programs.[18] The Company's proposal in this case to retain key adjustment mechanisms is consistent with that Decision.

Similarly, as I mentioned in my Direct Testimony, the SRB includes a very specific framework for filing and review as well as stakeholder engagement. These terms were discussed in depth and adjudicated in a prior Rate Case. I will discuss later in my Rebuttal Testimony circumstances or positions that could facilitate eliminating the SRB, along with APS's current TEAM adjustor, in the event the FRAM is adopted.

Q. WOULD ADOPTION OF THE FRAM RESULT IN ANY OVER-RECOVERY OF COSTS IF THE COMPANY'S OTHER ADJUSTMENT MECHANISMS ARE LEFT IN PLACE?

A. No. Mr. Madsen states that the FRAM will compound bill increases if the SRB and PSA remain with other maximum limits.[19] I disagree, because there are no changes

[18] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Prop. for Ratemaking Purposes*, Docket No. E-01345A-22-0144, Decision No. 79293 (Mar. 5, 2024) (Decision No. 79293) at 41.

[19] Madsen Direct at 65-66.

to the types or levels of costs that are sought for recovery through the FRAM as they exist through base rates and adjustors today. The FRAM is simply a means to adjust recovery levels for those costs not already contained in an adjustor mechanism more frequently, which will allow for smaller, more gradual price changes. If the SRB and the FRAM remain as separate mechanisms, there would be no risk of duplication in recovery, as costs would be recovered in one adjustor mechanism or the FRAM, but not both. If costs are recovered in the SRB and transferred to the FRAM in an annual update, those costs will be concurrently removed from the SRB in the same manner that they would in a general rate case proceeding. This would avoid any risk of overlapping or duplication.

Q. DO YOU CONCUR WITH RUCO'S RECOMMENDATION TO APPLY PRODUCTIVITY CREDITS?

A. I do not, and testimony from Mr. Madsen contradicts the very premise that supports these credits. Mr. Madsen proposes productivity credits to embed an expectation of savings achieved by implementation of the FRAM, and he justifies their value through reduced staffing, lower consulting, and less legal fees.[20] Elsewhere in Mr. Madsen's testimony, he suggests that each FRAM annual reset will effectively become a full rate case, which is further at odds with RUCO's rationale for the productivity credit.[21]

In fact, if adopted, the FRAM will naturally pass on any benefit in lower payroll expense or fewer consulting and legal fees. This is because audited, actual financial statements are the underlying basis of the formula. If these costs are reduced, they will be reflected in the income statement, and the level of recovery sought annually

[20] *Id.* at 54-55.
[21] *Id.* at 117.

will be updated and the savings will be immediately passed on to customers. This is an example of the symmetry of the FRAM.

RUCO's proposed requirement of additional productivity credits would reflect a predetermined specific level of potential savings. Applying the annual formula would then result in a duplicative calculation that would overcompensate those savings erroneously. Under the FRAM, the actual realized savings would be included in the annual income statement. Thus, RUCO's proposal for an additional productivity credit, which would be layered on top of those actual realized savings, is unnecessary.

Q. IS THERE A COMPELLING REASON TO ADD A CAP TO THE FRAM ANNUAL RESET AMOUNT?

A. No. The FRAM will undergo a thorough annual review process inclusive of approval by the Commission, where each year's filing and circumstances will support the appropriate level of cost recovery. This structure exists in APS's FERC Formula Rate, and the absence of a cap has not resulted in the magnitude of increases that some intervenors suggest. Instead, as shown in my Direct Testimony, the performance of APS's uncapped FERC Formula Rate shows a history of modest rate increases and decreases, benefiting both APS and its customers.

Moreover, in the 2025 UNSg Rate Case, Mr. Smith asserted that additional caps or constraints were unnecessary because the proposed Annual Revenue Adjustment Mechanism (ARAM) included a built-in earnings deadband, and therefore already

would moderate rate changes between rate cases.[22] For this and other reasons, the Commission declined to impose any caps on the UNSg retail formula rate.[23]

Q. IS THERE A COMPELLING REASON TO ADD AN AGGREGATE CAP ON THE FRAM OVER THE COURSE OF THE FIVE ANNUAL RESETS?

A. No. Mr. Madsen recommends a FRAM structure that would include not only a floor and a cap but also a secondary floor and an aggregate cap over the course of the five-year period between rate cases. This additional aggregate cap would limit increases to 5% in total, considering increases and decreases on a cumulative basis.[24] RUCO's proposal should be rejected for several reasons.

First, this proposal is not supported with an example of a utility that operates effectively with this type of structure in place. Instead, RUCO merely references an Entergy Mississippi formula rate plan which has an annual cap of 4% based on unadjusted evaluation period revenues, not the structure RUCO recommends. APS is not aware of any North American regulated utility operating with a formula rate that features the complicated structure RUCO supports. Second, the proposed cap and collar with a secondary floor and an aggregate cap would result in an unnecessarily complex and confusing formula. Third, if a deeper revenue deficiency should occur, this structure would result in no rate adjustment. This would exacerbate the revenue shortfall and arbitrarily prevent the utility from being able to recover costs that may arise due to circumstances outside of its control, such

[22] Direct Rate Design Testimony of Ralph C. Smith (7/23/2025) in UNSg Rate Case at 28.
[23] *See In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges, etc.,* Docket No. G-04204A-24-0237 (UNSg Rate Case), Decision No. 81653 (Feb. 27, 2026) (Decision No. 81653) at 126-33 (discussing the elements of the UNSg retail formula rate, which includes none of the capping mechanisms suggested by RUCO).
[24] Madsen Direct at 9.

as storm damage costs, increasing interest rates, or inflationary impacts on equipment necessary to provide reliable electric service.

V. FRAM ANNUAL RATE RESET AND ALLOCATION

Q. EXPLAIN THE BENEFITS OF USING COSS RESULTS IN THE FRAM ANNUAL RATE RESET.

A. The Company continues to propose using the annual COSS results to determine the adjustment level that each rate class would receive. These adjustments would continue progress toward moving customer rate classes closer to recovering the level of cost necessary to serve each respective class.

In his Direct and Rebuttal Testimonies, APS witness Jamie R. Moe discusses a new method of assigning generation costs related to serving growth. This method would apply a direct assignment of these costs to ensure that generation procured to serve growth is apportioned to classes based on cost causation principles. The FRAM incorporates this methodology to ensure that the customers who contribute to increased costs pay their fair share and do not shift costs to other customers. This means, for example, that Residential and small-to-medium General Service customer classes, which are not growing to the same degree as other customer classes, would not bear the costs necessary to ensure reliable service for extra high load factor (XHLF) customers, such as data centers and similarly situated large, high load factor customers.

Q. WILL THE COMPANY'S PROPOSED DIRECT ASSIGNMENT METHODOLOGY APPLY EQUITABLY TO ALL CUSTOMER CLASSES?

A. Yes. Microsoft Corporation (Microsoft) witness Mark E. Garrett asserts that Microsoft supports paying its own way through just and reasonable rates that do

not shift costs to other customers.[25] Yet he also says that APS's FRAM with the direct assignment allocation targets data centers on XHLF and leads to unjust and unreasonable charges for all.[26] To address these claims, it's important to highlight that APS's allocation proposal applies to all customer classes, not just the XHLF rate class. Moreover, utilizing the COSS results to determine the annual FRAM rate reset ensures that rates are continuously updated for each customer class based on the costs incurred on behalf of that customer class.

Q. IS IT IMPORTANT TO UPDATE THE COSS ANNUALLY GIVEN THE UNPRECEDENTED LOAD GROWTH THAT IS OCCURRING IN THE COMPANY'S SERVICE TERRITORY?

A. Yes. Updating a COSS annually is crucial to protect residential and small-to-medium business customers from cost shifts. Although Ms. Billie LaConte and Mr. Gorman argue that an updated COSS should not be done each year, this update is particularly important in an environment in which unprecedented load growth is occurring and expected to continue into the foreseeable future.

Q. DO YOU AGREE WITH RUCO'S CLAIM THAT UPDATING THE COSS EACH YEAR IS ADMINISTRATIVELY INEFFICIENT AND WILL INCREASE COSTS TO CUSTOMERS?

A. No. While the Company's proposal provides for updated COSS inputs on an annual basis, the proposal does not alter the underlying COSS methodology or cost allocation methods that are adopted during a general rate case proceeding. This is very similar to the calculation performed each year to comply with the Company's LFCR earnings test. As such, any additional administrative cost of performing this updated study each year is not significant, and the benefits of performing an

[25] Microsoft, Direct Testimony of Mark E. Garrett (Mar. 2, 2026) (Garrett Direct) at 16.
[26] *Id*. at 11.

updated study each year to ensure that growth pays for growth far outweigh any administrative burdens to perform it.

Utilizing an annual COSS in conjunction with an annual FRAM filing allows rates to adjust at a rate class level to provide for closer alignment between rates and costs by class on an annual basis. In an environment of significant load growth, updating the COSS annually will allow the FRAM to capture updated cost information, and assist in ensuring that growth pays for growth and residential customers do not experience cost shifts from large load customers.

Q. IS IT SURPRISING THAT RUCO IS ADVOCATING AGAINST AN ANNUAL COSS?

A. Yes. An annual COSS is the best method of ensuring that residential customers do not receive cost shifts from other rate classes. RUCO's position is extremely surprising given their stated mission of protecting residential customers. As RUCO is aware, the Company expects significant load growth in its service territory, primarily related to large high load factor customers, such as data centers. It is clearly in residential customers' best interest to annually evaluate what it costs to serve each rate class, and utilizing a COSS in conjunction with the FRAM works to mitigate cost shifts among customer classes.

Q. CAN YOU DESCRIBE HOW THE ANNUAL FRAM CALCULATIONS WOULD BE PERFORMED IN MORE DETAIL?

A. Yes, and I will discuss the process step by step. First, each year the FRAM earnings test will be performed to determine if a rate adjustment is warranted based on the deadband requirements specified in the POA.

Next, in the event a rate adjustment is appropriate, the annual COSS will then be utilized to see how much of that adjustment would be allocated to each rate class.

Note, this is contrary to assertions by Ms. Whited, who incorrectly claims that cost allocations will be maintained between rate cases.[27] Because a COSS will be performed annually, cost allocations will be updated to mitigate cost shifts between rate cases. To ensure that rate classes get the benefit of sales growth, and not just the associated costs, the current year's actual revenues will be applied to determine the class level revenue deficiency or surplus. This allocation will include the parameters I described in my Direct Testimony to ensure Extra Large General Service rates (including E-34, E-35, and XHLF) receive the adjustment needed to achieve 100% of their cost of service.

The adjustment to Residential rates and all other General Service rates will be calculated by determining the level of adjustment needed to bring these rate classes to 100% of their corresponding cost of service but then limiting those adjustments to fall between 0.85 and 1.15 times the annual average adjustment. This means that a class paying more than their cost of service could receive less than the average adjustment to bring the class closer to parity, while a class achieving less than their cost of service could receive slightly more than the average adjustment. Figure 1 below illustrates how this will function.

Last, this class level percentage will be applied to the total class level amount of base rate revenue, and it will appear as the Formula Rate Adjustment line item on the bill.

[27] Whited Direct at 21.

Figure 1. Illustrative Allocation Average Increase Modifier

Avg Increase	1.292%

Rate	% Cost of Service	Average increase modifier	% Increase
R-1 S	71.48%	1.15	1.486%
R-1 M	90.79%	1.15	1.486%
R-1 L	120.61%	0.85	1.099%
GS-SchL	98.67%	1.00	1.292%
XHLF	97.11%	NA	2.977%

Q. WOULD ANNUAL FRAM ADJUSTMENTS INCLUDE PRIOR YEAR REVENUE DEFICIENCIES?

A. No. The FRAM annual adjustment will utilize the earnings test from the prior calendar year to determine whether rates in effect result in revenues that allow the utility to achieve a return within the authorized deadband. If revenues result in achieving a return above or below the deadband, an adjustment will be made through the FRAM to align revenues with costs prospectively. For example, if the Company experienced a $25 million revenue deficiency in one year, the adjustment would seek to adjust recovery through the FRAM adjustment to achieve the authorized return, but it would not add the prior year's deficiency to the prospective year FRAM calculation, nor would it build on or compound the increase as RUCO suggests.

Q. PLEASE EXPLAIN WHY HISTORICAL EARNING RESULTS ARE NOT REFLECTIVE OF ANNUAL FORMULA RATE ADJUSTMENTS.

A. Mr. Madsen references a request seeking what the last 10 years of FRAM adjustments would have been, and claims that the Company provided inadequate information to fully understand future impacts. However, evaluating historic performance of the Company cannot serve to represent the level of revenue

deficiency or surplus that would have existed, because an annual formula adjustment mechanism did not exist during this period.

Instead, the Company's actual historic results reflect multiple years of accumulated costs with no rate alignment, which is not a fair representation of what an annual formula adjustment would require. Creating a hypothetical illustration of this would require speculative assumptions that an annual formula adjustment existed prior to the 10-year period being evaluated. Such assumptions are necessary to ensure that the first year under evaluation included representative revenues, including cost recovery for prior year investments and expenses.

Rather than looking at hypothetical historic performance without a formula rate in place, it is helpful to look at other jurisdictions with formula rate plans as well as APS's own history of TCA impacts. Although RUCO and other intervenors claim that rate decreases are unlikely under a formula rate, both examples dispel that notion. For instance, Entergy Mississippi is an example that RUCO refers to in testimony. Evaluating Entergy Mississippi's price changes for the last several years shows that there have been multiple years of price decreases while operating with a formula rate plan, and they have maintained rates below the national average (*see* Figure 2).[28]

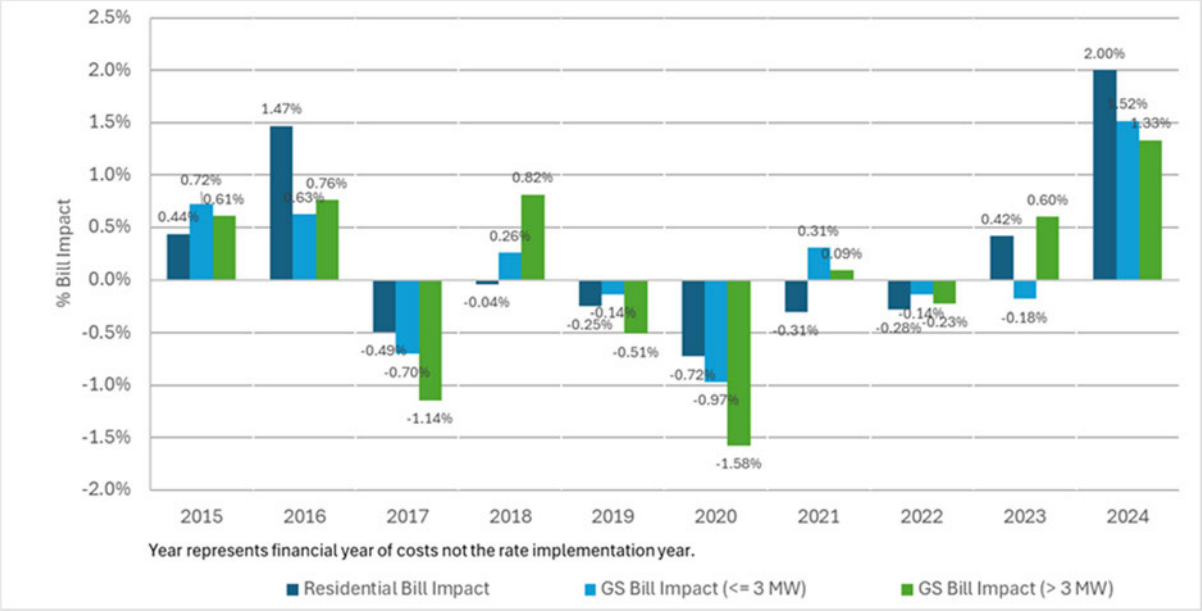
[28] Entergy Team, *As temperatures rise, Entergy Mississippi's rates drop,* Entergy (Jun. 14, 2023) https://www.entergy.com/news/as-temperatures-rise-entergy-mississippi-s-rates-drop; Entergy Team, *Public Service Commission approves Entergy Mississippi's plan to keep bills stable this summer,* Entergy (Jun. 13, 2024), https://www.entergy.com/news/public-service-commission-approves-entergy-mississippi-s-plan-keep-bills-stable-during-summer-mon; Entergy Team, *Rates to remain stable for Entergy Mississippi customers,* Entergy (Jun. 19, 2025), https://www.entergy.com/news/rates-to-remain-stable-for-entergy-mississippi-customers.

Figure 2. Entergy Mississippi Residential Rate Adjustments – 2023-2025

Year	Entergy Mississippi Residential Rate Adjustment
2023	$7.08 average decrease
2024	$2.07 average decrease
2025	$0.04 average decrease

Similarly, the last ten years of APS TCA adjustments are shown in Figure 3 below. This expands on the timeline of the graph included in my Direct testimony and makes some very minor calculation corrections. Out of the ten adjustments, residential customers saw five rate decreases.

Figure 3. APS TCA Adjustment



Q. DO YOU AGREE THAT NORMALIZATION ADJUSTMENTS SHOULD BE REMOVED FROM THE FRAM?

A. I would agree that many of the normalization adjustments that are necessary in a traditional rate case, that work to align multiple years in the future to a typical operating year, are not necessary in the FRAM which annually adjusts the rate to

align with actual costs. This is reflected in the FRAM POA under the Annual Update definition described in Section 2: "The filing will be based on APS's most recently filed Federal Energy Regulatory Commission FERC Form No. 1, using Historical Test Year costs, revenues, and other financial information, with certain pro forma adjustments necessary to annualize base revenues net of base fuel as applicable, interest synchronization and tax normalization, account for crisis bill spending, or adjustments related to surcharges and explicit items removed or otherwise adjusted in the Company's most recently approved rate case applicable to the evaluation year."[29]

It is, however, necessary to reflect certain normalization adjustments in the 2024 Test Year revenues ensuring that an appropriate baseline is established to support future FRAM adjustments.

Q. CAN YOU DISCUSS HOW ALLOCATING THE ANNUAL FRAM ADJUSTMENT UNDER ALTERNATIVE PROPOSALS WOULD IMPACT CUSTOMERS?

A. Mr. Madsen recommends that instead of performing an annual COSS for rate allocation, 100% of the FRAM adjustment should flow through the delivery rate component, although later acknowledging that there may be a need to update this allocation if cross-subsidization occurs, and that the basic service charge should be held flat so the entirety of the change would flow through volumetric rates.[30] First, it is important to clarify that there appears to be a misunderstanding that the Company is proposing to adjust each base rate component by the designated percentage annually which I address in more detail above. Next, applying the proposed level of base rate increase in this proceeding under the delivery or

[29] APS, FRAM POA at 1, Section 2.
[30] Madsen Direct at 67.

distribution rate approach that Mr. Madsen recommends results in Residential customers receiving a significantly larger allocation and larger General Service classes receiving less, as shown in Figure 4.

Figure 4. FRAM Allocation Methodology – APS versus RUCO[31]

	Proposed Allocation	Distribution Allocation	Increase (Proposed Allocation)	Increase (Distribution Allocation)	Difference
Residential	53.42%	63.59%	$ 353,851,847	$ 421,249,005	$ 67,397,158
Other GS	27.81%	31.02%	$ 184,255,920	$ 205,480,209	$ 21,224,288
E34/E35	9.18%	3.85%	$ 60,779,974	$ 25,507,287	$ (35,272,687)
XHLF	9.59%	1.54%	$ 63,551,973	$ 10,203,213	$ (53,348,759)
Total	**100.00%**	**100.00%**	**$ 662,439,714**	**$ 662,439,714**	$ -

Q. DOES THE BURDEN OF PROOF TO DEMONSTRATE THAT COSTS WERE PRUDENTLY INCURRED REST WITH THE COMPANY?

A. No. Although I am not a lawyer, my understanding is that, pursuant to A.A.C. R14-2-103(A)(3)(l), investments made by APS are subject to a presumption of prudence, with the burden to rebut that presumption placed on those challenging the utility's expenditures.[32]

Despite State of Arizona witness Caryn Potter's statements to the contrary, the FRAM does not alter the burden of proof related to prudency of investments nor related to the justification of rate increases.[33] As with a general rate case proceeding, APS must justify each annual update, provide schedules and supporting data for each annual update, and respond to data requests and

[31] The values referenced are from the Application.

[32] *See* Arizona Administrative Code R14-2-103(A)(3)(l) ("All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made.").

[33] State of Arizona, Direct Testimony of Caryn Potter (Mar. 18, 2026) (Potter Direct) at 17.

challenges. The Commission and intervenors also maintain their oversight functions as with a general rate case proceeding. So, while APS has the obligation to demonstrate that an annual adjustment is warranted under the FRAM POA, specifically with respect to the question of whether APS's expenditures are "prudently" incurred, APS's investments are still subject to a presumption of prudency.

Q. IS APS PROPOSING ANY WAYS TO FACILITATE ANNUAL PRUDENCY REVIEWS?

A. Yes. To facilitate a more transparent and accessible review during the challenge period, APS is proposing to also provide an overview of major expense drivers and capital investments as a part of each annual FRAM filing. This is consistent with the materials that APS provides today as part of its FERC Formula Rate annual process. This will enable greater access to information regarding any significant factors contributing to a given annual FRAM adjustment. Consistent with the Commission-approved UNSg ARAM, APS is also proposing to provide quarterly capital investment reporting, which will further enhance transparency and prudence reviews by interested parties as part of the annual FRAM adjustment process.[34] Multiple intervenors, such as Ms. LaConte[35], support supplementing APS's proposed FRAM with these additional procedures, and APS supports such enhancements.[36]

VI. FRAM ANNUAL FILING AND TIMELINE

Q. PLEASE DISCUSS INTERVENOR CONCERNS REGARDING THE INTERIM EFFECTIVE DATE OF THE PROPOSED FRAM.

A. Interim adjustor rates are not an uncommon ratemaking feature and have been used in both Arizona and various other jurisdictions around the country. The FERC

[34] *See* Decision No. 81653, Exhibit A at 10.
[35] LaConte Direct at 14-15, 23-24.
[36] *Id.*

formula rate (and associated TCA adjustor) provides for an interim rate effective date that is implemented pursuant to an established POA, with later review and approval by the Commission. In addition to the Company's FERC formula rate interim adjustment provision, many utilities in other jurisdictions with retail formula rate plans also provide for interim rate adjustments, with subsequent commission approval, such as Entergy Mississippi, Mississippi Power, and Entergy Louisiana.

An interim effective rate is the best method to achieve the goals of reduced regulatory lag while also maintaining a sufficient review timeline for the Commission and intervenors. Due to the FRAM's use of a historical test year, costs incurred at the beginning of the test year period will already experience regulatory lag of more than 20 months under the Company's current proposal. Any extension to the effective date beyond the Company's proposal will exacerbate this regulatory lag. However, in an effort to more closely align with Staff and other intervening parties' recommendations, the Company would agree to a FRAM reset after the challenge and review period described in the POA as long as other provisions remain intact and that 2026 serves as the first FRAM test year (see Attachment JEH-03RB). This process would retain a mechanism that enables Commission approval before any FRAM adjustment taking effect. I discuss these proposed changes further below, but in general these proposed modifications to the FRAM are intended to reflect an overall package that achieves closer alignment with Staff and intervening parties in this case while at the same time establishing a mechanism with predictable timing as to annual rate adjustments.

Q. ARE THERE MATERIAL DIFFERENCES BETWEEN ENTERGY ARKANSAS' FORMULA RATE PLAN AND APS'S PROPOSED FORMULA RATE PLAN?

A. Yes. While both formula plans include annual calculations based on an established formula, there are significant differences between the protocols within Entergy Arkansas' existing formula rate plan and APS's proposed FRAM. Entergy Arkansas' uses a projected test year, utilizing estimated forecasted values for various cost categories, while APS's proposed FRAM uses a historical test year's actual costs. Forecasted test years require speculative judgment and result in more disputes regarding how each cost category is estimated. APS's proposed FRAM, because it is premised upon actual, verified historic costs, avoids these complications and enables a more streamlined, efficient review process.

Q. DOES THE PROPOSED FRAM PROVIDE ADEQUATE TIME FOR STAKEHOLDERS TO ANALYZE THE ANNUAL FILING AND THE PRUDENCY OF COSTS?

A. Yes. The FRAM schedule is designed to allow time to review a narrower range of costs and inputs as compared to a traditional general rate case proceeding. Many of the highly contested issues will not be subject to change between rate case proceedings and will not require analysis by interested parties. A general rate case requires parties to review and analyze a wide range of foundational issues, including ROE, capital structure, structural rate design changes, cost allocation methodologies, tariff and service policy changes, and numerous other highly contested matters of energy policy, as well as a large number of pro forma adjustments that may change with each rate case filing. In this specific rate case, SFR C-2 includes 65 income statement pro forma adjustments and SFR B-2 includes 17 rate base pro forma adjustments. Under the proposed FRAM, however, interested parties will be able to focus their evaluation of the annual FRAM filing

on specific expense categories and inputs to the established formula rather than the broad range of issues that parties usually analyze, brief, testify, and argue in a full rate case proceeding.

Thus, various intervening parties mistakenly refer to this process as a "mini-rate case," which it most certainly is not. Instead, the annual FRAM review process imposes more frequent, focused review on contemporaneous costs and expenses, while leaving in place traditional general rate cases to address the wide-ranging policy issues such proceedings have always evaluated.

As discussed by RUCO witness Jeffrey Michlik in the 2025 UNSg Rate Case proceeding, RUCO has extensive experience evaluating utility earnings tests, which forms the foundation of APS's proposed FRAM. As demonstrated by RUCO's prior review of various utility company capital investment tracking mechanisms (such as the System Impact Benefit mechanism), utilizing a consistent formula and earnings test allows intervenors to easily follow the calculation and target their analysis to specific costs or sections of the annual filing.[37] As such, shifting to an annual formula reset process should not impose any new or unfamiliar burdens on stakeholder participants, who already have expertise and familiarity with precisely the kind of evaluation necessary for a FRAM reset.

Q. PLEASE ADDRESS MS. WHITED'S ASSERTION THAT PRUDENCY MAY NOT BE CHALLENGED UNDER THE PROPOSED FRAM PROTOCOLS.

A. As the Company indicated in its data request responses to Sierra Club, the Company believes that the language in the proposed FRAM POA allows for parties to challenge the prudency of costs. The POA states that parties may challenge

[37] UNSg Rate Case, Tr. Vol. VI (Oct. 16, 2025) at 972-74 (Michlik).

"whether the Annual Update fails to include data properly recorded in accordance with these protocols (*see* JEH-01RB)." The POA also states on page 4, item (xi), as a part of the FRAM protocols, that the FRAM shall "Include the costs of new 'prudently invested' plant placed into service that are used and useful for APS customers consistent with Arizona Administrative Code ('A.A.C.') R14-2-103(A)(3)(1) (*see* JEH-01RB)." Taken together, these items provide for parties to challenge the prudency of costs included in each FRAM annual calculation.

However, in order to accommodate concerns of stakeholders, the Company is willing to amend the FRAM POA to expressly provide for challenges of prudency. As such, the Company will be offering an amended FRAM POA (*see* Attachment JEH-03RB) that adds an additional item to Section 6(c) that states "to determine the prudence of the costs and expenditures included for recovery in the Annual Update."

Q. PLEASE RESPOND TO INTERVENOR CONCERNS RELATED TO THE TIMELINE OF THE INFORMATION EXCHANGE AND CHALLENGE PERIODS.

A. The proposed FRAM timeline was developed in consideration of the Commission's Policy Statement as well as the FERC Formula Rate protocols upon which the FRAM is modeled. The Company's proposal was developed to accommodate the Commission's goals of meaningfully reducing regulatory lag and meet the 120-day timeline included in the Commission's Policy Statement. Because the scope of the FRAM annual update is far more narrow than the scope of a general rate case proceeding, the Company believes sufficient time is provided in its proposal to accommodate interested party data requests and challenges. However, based on the concerns raised by some of the parties, the Company is proposing an extension to the Informal Challenge period timeline to provide an

additional seven days for interested parties to submit Informal Challenges, in a good-faith effort to address parties' concerns with the originally proposed timeline.

Q. IS THE COMPANY PROPOSING OTHER CHANGES TO THE PROPOSED FRAM TIMELINE?

A. Yes. To address stakeholder concerns with the Application's proposed FRAM protocols and timeline, the Company has revised the FRAM POA to allow for Interested Parties that have not issued Informal Challenges to submit Formal Challenges. This update is being offered in the spirit of providing ample time for stakeholders to review the FRAM schedules, underlying data, and data request responses, and submit challenges if deemed necessary. With this revision to the FRAM protocols, parties will now have nearly two months to submit challenges from the initial filing of the Annual Update through the last day to Submit Formal Challenges, even if they have not issued an Informal Challenge during the Informal Challenge Period.

Q. DO YOU HAVE ANY ADDITIONAL CHANGES TO THE LANGUAGE IN THE FRAM POA?

A. Yes. The FRAM POA discusses that a base revenue annualization adjustment is necessary when there is a general rate case rate adjustment that occurs during a FRAM test year. This annualization is necessary to ensure that customers get the benefit of the additional revenue that the Company will recover prospectively with those new rates in effect. The FRAM POA has been updated to propose that this revenue annualization amount is net of Base Fuel, which is necessary because the PSA mechanism already exists to adjust rates to recover the difference between actual fuel-related costs and what is authorized for recovery in base rates, plus the PSA surcharge. Due to this relationship between the Base Fuel rate and the PSA, Base Fuel expense is limited to the authorized Base Fuel rate in effect at the time. Consequently, it is appropriate to account for the subsequent year's change in Base

Fuel revenues from the base revenue annualization pro forma, when applicable, in a FRAM filing.

Q. PLEASE DISCUSS ANY REMAINING UPDATES THE COMPANY IS PROPOSING TO ITS ORIGINALLY FILED FRAM POA.

A. In addition to the revisions discussed previously in my testimony, the Company is also revising the FRAM protocols to require quarterly reporting of asset additions, to be consistent with the outcome of the UNSg Rate Case and the approved ARAM protocols. The Company is also accepting Mr. Smith's recommendation to revise the PTYP period to six months, consistent with UNSg's ARAM and the objective of the Commission that formula rate plans be based on actual, verifiable information, rather than using projections or estimates (see Attachment JEH-03RB). The use of six months of PTYP will mean that all of the capital projects included in each FRAM annual filing will be in-service and providing benefit to customers prior to the filing of the annual update. These changes are made on the basis of achieving a 2026 FRAM test year with six months of projected plant reflected in the Company's first FRAM filing in 2027.

Q. PLEASE DISCUSS RUCO'S RECOMMENDATION TO EXTEND THE EFFECTIVE DATE FROM 120 DAYS AFTER PUBLICATION OF THE ANNUAL FILING TO 270 DAYS.

A. The Company's proposed FRAM timeline was developed in consideration of the Commission's Policy Statement, which expressly provides for a 120-day review period following the publication of the annual filing to Commission decision. The timeline was also developed to achieve the benefits of reduced regulatory lag, which in turn lowers the utility's financing costs (as discussed by Mr. Bauer in his Direct and Rebuttal Testimonies). RUCO's proposed extension of the timeline to 270 days from filing to effective date of new rates would eliminate the benefits

cited by the Commission when it issued its policy statement.[38] In addition, the FRAM relies upon annual financials that are used to update an established template based only on actual costs and expenses recently incurred. Thus, as discussed earlier in my testimony, significantly less review time will be required as compared to a general rate case, as contentious components, such as ROE, will not be adjusted between rate cases.

Q. DOES THE PROPOSED FRAM RESULT IN AUTOMATIC ADJUSTMENTS THAT UNDERMINE THE REGULATORY PROCESS?

A. No. While the initial proposal in the FRAM POA included a provision that interim rates go into effect pending the review period, I discussed earlier in testimony that the Company has now proposed to modify the FRAM POA to allow the rate reset to occur at the end of the stakeholder process and formal challenge period unless otherwise contested (*see* Attachment JEH-03RB). This structure will require Commission approval within a specified timeframe, in order to ensure predictable timing for rate adjustments and more effectively reduce regulatory lag. Under no circumstances will a new FRAM rate take effect without the Commission's approval (either explicitly or through assent). This approach ensures that FRAM rate adjustments will never be automatic and that the Commission maintains its responsibility to review and approve the Company's rate updates. Assuming the proposed parameters within the FRAM are adopted, the Company would agree with Mr. Smith that a true-up would no longer be necessary.

Although an interim rate is no longer proposed, I disagree with Mr. Madsen's comments regarding intergenerational cost shifts that would supposedly result from the use of an interim rate. In fact, under the current traditional rate case process, intergenerational cost shifts are much more significant than would be

[38] Madsen Direct at 62, lines 1-2.

through the proposed FRAM due to the delay in cost recovery. For this reason alone, the FRAM would be a dramatic improvement regarding the intergenerational cost shifts that RUCO witness Mr. Madsen describes. In addition, the concern regarding intergenerational cost shifts would be exacerbated if Mr. Madsen's proposed extended timeline of 270 days were used. This extended timeline would increase regulatory lag and shift recovery of expenses to an even later period.

Q. WHAT INFORMATION WILL THE COMPANY INCLUDE WITH EACH ANNUAL FRAM FILING?

A. As reflected in the proposed FRAM provisions, APS is committed to providing comprehensive data, supporting documentation, and disclosures sufficient for intervenors and the Commission to conduct a thorough review of the FRAM filing and underlying data. For example, Item (ix) in Section 3 of the proposed FRAM POA states: "To the extent Accounting Changes and other matters affect APS's inputs to its FRAM, [the Company will] provide a narrative explanation of the individual impact of those items on charges billed under the FRAM (*see* JEH-01RB)."

In addition, APS is proposing revisions to the FRAM that will enhance the ability of intervenors and Staff to review APS's annual FRAM reset filing. In addition to building off quarterly capital investment reports, the annual filing will now include a report on specific cost drivers and major capital investments impacting each annual reset.

Q. PLEASE RESPOND TO WALMART'S RECOMMENDATION OF A MANDATORY FIVE-YEAR RATE CASE STAY-OUT.

A. Dr. McGovern characterizes the FRAM as reducing regulatory scrutiny and insulating shareholders from normal business risk, and on that basis recommends

a mandatory five-year stay-out if the FRAM were approved.[39] However, a mandatory stay-out does not restore the supposed lost regulatory scrutiny Walmart alleges. To the contrary, this recommendation would eliminate the Commission's most comprehensive review mechanism that is provided through a general rate case proceeding, if one was needed. A five-year stay-out requirement would constrain the Commission, and the Company's discretion by foreclosing a general rate case even if there is a material change in circumstances. Walmart's stay-out recommendation would therefore not increase customer protection and would instead limit corrective options.

Q. DOES THE COMMISSION RELY SOLELY ON AUDITED FINANCIAL STATEMENTS WHEN ASSESSING THE ANNUAL FORMULA RATE UPDATE AND DETERMINING PRUDENCY?

A. No. Despite RUCO's arguments to the contrary, FRAM annual filings will continue to be subject to full ratemaking scrutiny through formula rate annual compliance filings. These compliance filings serve to increase transparency through more regularly scheduled stakeholder engagement. They also enable better protection of ratepayers through annual audits of underlying costs and inputs that go into the calculation of the formula rate plan. Any costs that are ordered to be disallowed from the previous rate case will be captured through a pro forma adjustment in the formula rate plan filing.

Analysis of formula rate filings will have the same rigor as a rate case, but with a narrower scope (as discussed earlier). This rigorous, yet narrower scope is similar to SRB prudence reviews and will include pro formas that are updated to remove disallowances in the same manner as the LFCR earnings test today. While Ms. Potter implies that the SRB and subsequent transfer into the FRAM will make it

[39] McGovern Direct at 4.

more difficult to determine prudency, the opposite is true.[40] Analysis of a single large generation project will allow for a targeted review, and information regarding APS's wholistic operations will still be available. This, paired with the more frequent reporting that is provided through annual FRAM update filings, would make a prudency analysis easier, and not more difficult as a result of the SRB working in tandem with the FRAM. Notwithstanding the position that both can work in tandem, the Company is willing to accept the elimination of the SRB adjustor mechanism, provided that the FRAM is adopted and the proposed 120-day timeline and other provisions remain. This position aligns with Staff and intervening parties who contend that SRB related costs could be recovered in the annual FRAM filing.

Q. PLEASE ADDRESS MR. MADSEN'S OPINION THAT FAILURE TO REPORT UNIQUE COSTS THAT ARE LATER DISCOVERED DURING THE REVIEW PERIOD SHOULD BE DISALLOWED AND REFUNDED TO CUSTOMERS RETROACTIVELY.

A. The annual FRAM filing will include reporting of all costs included in the FRAM calculation, along with a narrative summary of test year costs and primary drivers, as described earlier in my Rebuttal Testimony. It is unclear what specific reporting that Mr. Madsen is referring to in this section of his testimony, as reporting of costs and underlying data is central to the proposed FRAM process. Along with the reporting requirements already included in each annual formula filing, interested parties may request additional supporting data, submit data requests regarding any included cost, and may challenge costs or inputs that are deemed inappropriate. Disallowances of costs would only be appropriate if determined to be imprudent by the Commission as a result of their review of the annual filing or the challenges submitted by interested parties.

[40] Potter Direct at 15.

Q. DOES THE PROPOSED FRAM REDUCE MEANINGFUL STAKEHOLDER PARTICIPATION IN THE RATEMAKING PROCESS?

A. No. The proposed FRAM increases stakeholder engagement in the ratemaking process. It provides the ability for interested parties and the Commission to review the Company's costs on a more frequent basis as compared with the traditional rate case process, which can have multiple-year gaps between test years. The proposed information exchange and challenge period process allows interested parties to request supporting data underlying the annual formula filing. Parties may also submit challenges based on their review of the filing and underlying data.

VII. FRAM ALTERNATIVE POSITIONS

Q. DO INTERVENORS SUPPORT THE FRAM PROPOSAL?

A. Yes. Some intervenors recommend approval of the FRAM, including Staff and IBEW, while others suggest either modifications to the FRAM, or alternative proposals that I will address specifically in more detail.[41]

Q. WOULD A DISTRIBUTION CAPITAL TRACKER BE A SUFFICIENT ALTERNATIVE TO THE FRAM?

A. No. Distribution-related costs represent only 23% of the Company's total revenue requirement in this case. Implementing a distribution capital tracker, as Ms. LaConte suggests, would limit the ability to update rates to align with costs and therefore would not serve as a suitable alternative.[42] As discussed in more detail by Mr. Bauer in his Rebuttal Testimony, improving cost recovery times for capital costs does nothing to address the significant regulatory lag APS experiences as a result of increasing operations and maintenance expenses. Even if Ms. LaConte's proposed tracking mechanism covered a wider scope of capital investments beyond APS's distribution system, which it does not, it would still fall well short of

[41] Smith Direct-Rate Design, Executive Summary at ii; Carpenter Direct at 9.
[42] LaConte Direct at 20-21.

satisfying the Commission's goal of reducing regulatory lag for both investment costs and all other utility operating expenses.

Q. HOW WOULD YOU ADDRESS THE CLAIM THAT THE FRAM WEAKENS COMMISSION OVERSIGHT AND SHIFTS RISK TO CUSTOMERS?

A. First, APS's proposed FRAM allows for more oversight and transparency than the current structure, where such supervision is largely limited to periodic general rate cases. Today, all of the detailed financial schedules and workpapers for Arizona utility companies are typically provided once every three to five years when a general rate case is filed. By contrast, the FRAM would allow for annual review of all expenses and investments each and every year. Not only does this increase transparency, it better balances the workload to review the material, including time dedicated to reviewing the annual LFCR earnings test that would be eliminated with the adoption of the FRAM. APS is also now proposing to eliminate the SRB and TEAM mechanisms as standalone adjustors, which further streamlines cost recovery with the FRAM. Coupled with the quarterly capital investment reporting that APS is also now proposing to provide, the FRAM will substantially increase Commission oversight as to APS's expenditures.

Second, the FRAM would not shift risk to customers because the same ratemaking principles and prudency determination structure exists with more regular exposure to investments and expenses to improve regulatory lag. Mr. Geisler's and Mr. Bauer's Rebuttal Testimonies further addresses questions around risk and how the FRAM maintains current utility company cost control incentives.

Q. IS IT FAIR TO CHARACTERIZE THE FRAM AS A ONE-SIDED MECHANISM?

A. No. I disagree with Dr. McGovern that the mechanism is one sided. I also disagree with Mr. Madsen, who asserts that the FRAM will pass on cost increases due to interest rate increases, unfavorable weather revenue, declining annual sales and customer counts, as well as increasing operating and capital costs related to inflation. These viewpoints do not acknowledge that these same variables can just as easily create savings for customers each year when they move in the other direction (i.e., reduced interest rates, favorable weather, increased growth-related revenue, and reductions in inflationary pressure).[43] The symmetry of the FRAM enables these savings to benefit customers contemporaneously.

Q. PLEASE ADDRESS CLAIMS THAT THE FRAM WILL RESULT IN COMPOUNDING ANNUAL RATE INCREASES.

A. Because the FRAM looks each year at expenses and revenues to decide whether an adjustment is permissible, and what magnitude of an adjustment is appropriate, that assessment will reflect any prior year's adjustment to revenues. This means that if the Company were deficient last year and adjusted the FRAM upward to achieve a 2% increase, the subsequent year's revenue would reflect that 2% and seek to calculate only the year over year incremental difference needed to align with the authorized return. Thus, simply using a multi-year rate case result and dividing the value by the number of years the FRAM resets is not indicative of what will be experienced. Stated another way, if a five-year rate increase would have resulted in a 10% net increase, you cannot divide 10% by five years and assume that under a formula rates, would have increased 2% annually. Because this simplistic compounding illustration does not take into account incremental revenue increases,

[43] McGovern Direct at 4, 11; Madsen Direct at 6.

it does not provide a useful way to evaluate how the FRAM would realistically function.

Q. PLEASE RESPOND TO MS. WHITED'S ASSERTION THAT FORMULA RATE PLANS HAVE RESULTED IN LARGER COST INCREASES IN OTHER JURISDICTIONS.

A. In her testimony, Ms. Whited references states such as Arkansas, Illinois, Alabama, and Maryland, and indicates that the rates seen in these jurisdictions have increased since the adoption of retail formula rate mechanisms.[44] However, based on a review of these various jurisdictions, I have not seen evidence that the establishment of formula rate mechanisms was the cause of increasing electric prices when compared to a hypothetical history of not having enacted formula rate mechanisms.

There are many factors that can lead to electricity price increases. For example, Illinois passed an energy infrastructure and modernization act in 2011 and adopted formula rate plans to support investments in grid modernization.[45] This example calls into substantial question the assertion that formula rate plans directly caused increases in rates. Instead, a need for infrastructure and grid modernization improvements, and the associated large-scale investments, instigated the establishment of formula rate plans to recover these costs. The method of recovering costs in and of itself cannot be said to be the catalyst of rate increases. Rather, when large-scale investment is needed, it is the large-scale investment that causes rate base to increase. In the absence of a formula rate plan, a utility would still require plant investment, and recovery of these investments would still be

[44] Whited Direct at 11-18.

[45] ComEd, *Illinois General Assembly Enacts Energy Infrastructure Modernization Act,* PR Newswire (Oct. 27, 2011), https://www.prnewswire.com/news-releases/illinois-general-assembly-enacts-energy-infrastructure-modernization-act-132681088.html.

recovered through a general rate case proceeding rather than through a formula adjustor mechanism.

Mr. Maden's comments related to Atmos Energy should similarly be disregarded. Atmos Energy is not a relevant example to this rate case proceeding. First, there is no evidence that the establishment of formula rates for Atmos Energy was the precipitating factor for the rate increases that have been seen over the last few years. Atmos Energy's formula rate mechanism was established in the mid-2000s, and, prior to 2024, Atmos Energy had among the lowest rates for gas service in Mississippi.[46] After an incident in 2024, Atmos increased its capital spending by more than 50% annually for system integrity upgrades.[47] In this circumstance, there were drivers totally unrelated to the utility company's cost recovery mechanism that drove an increase in system investment. As such, Atmos Energy does not demonstrate the failure of formula rate mechanisms, but is simply an obvious demonstration of a utility company increasing investment in response to a demonstrated system need.

Further, many of the jurisdictions listed by Sierra Club have multi-year rate plans rather than formula rate mechanisms. These plans differ in crucial ways. For example, many multi-year rate plans use forecasted costs and revenues, in contrast with the use of historical costs and revenues with limited pro forma adjustments, such as the FRAM.

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[46] Docket No. 2025-UN-59, Notice of Intent Of Atmos Energy Corporation To Change Rates to Support System Integrity Plan and Continued Modernization of Infrastructure, at 7.

[47] Pam Dankins, *NTSB opens public docket in investigation of 2 fatal Jackson home gas explosions in 2024,* Mississippi Clarion Ledger (Jan. 15, 2025), https://www.clarionledger.com/story/news/local/2025/01/15/ntsb-investigates-january-2024-home-gas-explosions-killed-1-in-jackson-ms/77723724007/.

Finally, the Company performed an analysis of eight utilities with formula rate plans in Alabama, Arkansas, Louisiana, and Mississippi, who have all been operating with formula rate plans for multiple years to understand average residential electricity rates for these utilities compared to the average United States utility rate. Based on this analysis, average residential electricity rates for these utilities is about 17% lower than the average residential rates of utilities across the county (excluding California and Hawaii), based on 2025 EIA data.[48]

Q. PLEASE DISCUSS THE REFERENCE MADE TO THE NATIONAL REGULATORY RESEARCH INSTITUTE (NRRI) BRIEFING PAPER BY KEN COSTELLO.

A. Mr. Madsen cites this NRRI paper and refers to a statement that a badly structured formula rate plan (FRP) can produce poor incentives, causing customers to pay more. Mr. Madsen does not, however, acknowledge that elsewhere in the same document, Mr. Costello states on page 4 that "[This paper] advises regulators to have an open mind about FRPs. These rates do have some advantages over traditional ratemaking, but these advantages depend on details of design and execution."[49] The benefits of FRPs for both customers and utilities are further described on page 11 of the document.

Under the Company's proposed FRAM, the same incentives to control costs apply. As with the Company's existing adjustors, the Commission reviews each filing and supporting information annually, and the Company is incentivized to ensure that all costs are prudently incurred to avoid the risk of disallowance. Under the FRAM,

[48] 2025 U.S. Energy Information Administration (EIA) data pulled Mar. 10, 2026, https://www.eia.gov/electricity/data/eia861m/#salesrevenue.

[49] Ken Costello, *How should regulators view cost trackers?,* Electricity Journal, vol. 22, no. 10 (Dec. 2009), https://doi.org/10.1016/J.TEJ.2009.10.015

even greater scrutiny is expected due to the increased transparency provided by annual FRAM filings, showing clearly the annual expenses for various cost categories that were previously only available during a rate case test year.

Q. DOES THE FRAM ELIMINATE OR REDUCE ANY CUSTOMER PROTECTIONS?

A. No. In fact, the proposed FRAM provides additional customer protections through yearly reporting of financial information, alongside a requirement to respond to data requests and challenges on an annual basis, rather than only during a general rate case. Additional quarterly capital investment reporting, which APS now proposes to include with the FRAM, increases the Commission's oversight abilities and enables greater customer protection. In addition, a COSS will be prepared each year to ensure that customers are protected from cost shifts from other customer classes. The inherent earnings test included in the FRAM also ensures that rates can be adjusted downward following an annual FRAM reset in the event the Company earns greater than its authorized rate of return, providing yet another customer protection.

Q. DO INTERVENORS ALSO REFERENCE AN ACADIAN REPORT ON FORMULA RATES?

A. Yes. Mr. Madsen references this report and states that Acadian concluded that actual experiences with formula rates do not demonstrate that they create ratepayer benefits.[50] This same report was discussed and thoroughly dismissed during the 2025 UNSg Rate Case where Mr. Smith stated, "I wouldn't rely on anything that's stated in it. The conclusions or anything else."[51] Mr. Smith then highlighted several inaccuracies contained in the report and emphasized that these errors were apparent

[50] Madsen Direct at 23-25.

[51] Transcript Volume VIII from 10/20/2025 UNS Gas Hearing 24-0237, at 118 line 23-25.

upon initial review and could have been addressed if the author had consulted with others before filing the report.

Q. DOES THE COMPANY PROPOSE A CHANGE TO THE RENEWABLE ENERGY STANDARD ADJUSTMENT SCHEDULE (REAC) POA IF THE FRAM IS ADOPTED?

A. Yes. To accommodate the Company's proposal to eliminate the LFCR adjustor after the first annual FRAM reset, the Company proposes to amend the REAC POA to allow LFCR distributed generation (DG) revenues to apply to the REAC in the event the FRAM is adopted. These proposed changes to the REAC POA are shown in Attachments JEH-04RB and JEH05RB). The Company notes that its proposed changes to the REAC POA are only necessary if the FRAM is adopted by the Commission.

VIII. RESIDENTIAL RATE DESIGN

Q. DOES APS HAVE ANY DESIGN CHANGES TO RESIDENTIAL RATES?

A. No. APS continues to support the rate design approach proposed in my Direct Testimony. Any proposed changes to rates were made to reflect the updated Rebuttal revenue requirement.

Q. DOES APS AGREE WITH WILDFIRE WITNESS CLAIRE MICHAEL THAT BASIC SERVICE CHARGES SHOULD NOT BE INCREASED?

A. No. An important part of rate design is fixed cost recovery through basic service charges. The Basic Service Charge is intended to recover fixed customer-related costs that do not vary with energy consumption, and shifting recovery of those costs to volumetric rates will continue cost misalignment and potential cross-subsidies among customers. This helps set appropriate price signals that enable customers to appropriately evaluate conservation effort and cost, without shifting costs to other customers. Staff witness Anthony Georgis reviewed APS's COSS and found that APS's proposal for the basic service charge was below the

level supported by the COSS of $23.27 per month.[52] While APS acknowledges Ms. Michael's concern regarding affordability, APS believes that increasing the Basic Service Charge is appropriate, the amount is consistent with or below the Basic Serve Charge for other Arizona utilities, and it is supported by the COSS in this case.

Q. HOW SHOULD THE COMMISSION CONSIDER THE NUMBER OF LETTERS SUBMITTED BY ARIZONA PUBLIC INTEREST RESEARCH GROUP EDUCATION FUND (ARIZONA PIRG EDUCATION FUND) IN THIS PROCEEDING?

A. Arizona PIRG Education Fund witness Diane E. Brown reports that Arizona PIRG Education Fund collected 570 letters from residential customers, roughly 0.05% of APS's residential customers, and 90 letters from small business owners, roughly 0.06% of APS's non-residential customers.[53] PIRG's own analysis shows customers had a positive opinion of APS, stating "Generally, customers are pleased with the reliable electricity service they receive.[54] They are generally positive about the company's customer service."[55] In general, the letters provide insight into customer concerns, and APS respects and values public participation in Commission proceedings. However, the number of letters submitted does not establish whether a proposed rate or rate design element is just and reasonable or cost-based, and they do not provide a basis for modifying APS's proposed rates.

[52] Amount reflects the level supported by the COSS included with the Application.
[53] Arizona PIRG Education Fund, Direct Testimony of Diane E. Brown (Mar. 18, 2026) at 2:9-15.
[54] *Id.* at 3.
[55] *Id*. at 3.

IX. GRID ACCESS CHARGE (GAC)

Q. IS THE COMPANY CHANGING ITS POSITION ON INCREASING THE GRID ACCESS CHARGE?

A. The only change to the GAC is the impact of an updated revenue requirement based on the additions I described earlier in my Rebuttal Testimony. The proposed charges are shown in Figure 5 below.

Figure 5. Rebuttal Revenue Requirement GAC Updates

GAC Rate	Present $/kW-DC	Proposed $/kW-DC	Difference $/kW-DC
R-TOU-E	0.242	0.605	0.363
R-2	0.250	0.734	0.484
R-3	0.215	0.593	0.378
R-EV	0.000	0.605	0.605

GAC Average Impact	Average kW-DC	Present $/month	Proposed $/month	Difference $/month
R-TOU-E	10	2.42	6.05	3.63
R-2	10	2.50	7.34	4.84
R-3	11	2.37	6.52	4.15
R-EV	11	0.00	6.66	6.66

Mr. Carpenter supports residential solar increases to base rates and the GAC. In addition, Mr. Georgis agrees that current and legacy solar customers are not fully recovering their cost of service and agrees that the proposed GAC and rates for legacy solar customers would bring those customer classes closer to their cost of service. It is important to recognize that, even with these increases, each affected customer class remains at least 20% below the calculated cost of service.[56]

[56] Carpenter Direct at 4:10-11; Staff, Direct Testimony of Anthony Georgis (Mar. 18, 2026) at 21:2-8.

Vote Solar witness Kate Bowman argues that solar charges are discriminatory and the Ms. Potter states that the Commission should not increase these charges and rates, given pending review by the Arizona Court of Appeals of APS's 2022 rate case.[57] However, multiple jurisdictions across the country apply GAC, minimum bills, or demand-based rate structures to DG customers to ensure more equitable recovery of fixed costs. These mechanisms, as seen in Figure 6 below, demonstrate that requiring DG customers to contribute to grid infrastructure consistent with their cost of service is a widely accepted and non-discriminatory ratemaking practice.

Figure 6. DG Fixed Cost Recovery Mechanisms

Utility	State	Mechanism	Charge Level
APS	AZ	Grid Access Charge	$0.242 per kW-dc/month
SRP	AZ	Fixed + demand-based DG rate	~$20-$40 fixed + up to ~$36/kW demand
Duke Energy Carolinas	NC	Minimum bill + grid access fee	$22/month + $2.05/kW
Duke Energy Progress	NC	Minimum bill + grid access fee	$28/month + $1.50/kW
Dominion Energy SC	SC	Minimum bill	$13.50/month
Rocky Mountain Power	UT	Minimum bill requirement	Varies by tariff
Austin Energy	TX	Demand-based DG rate	~$8.00/kW/month

X. LIMITED INCOME PROGRAM RECOMMENDATIONS

Q. PLEASE ADDRESS INTERVENOR PROPOSALS TO EXPAND THE LIMITED INCOME DISCOUNT PROGRAM.

A. Ms. Michael proposes that the Company add two additional tiers, increasing the two-tier discount program to four tiers and adding approximately $15 million in

[57] Vote Solar, Direct Testimony of Kate Bowman (Mar. 18, 2026) at 7:20; Potter Direct at 25:7-8.

additional funding. This additional funding would go above and beyond the current $10.8 million reflected in SFR C-2 column 24, which amortizes additional incremental costs to fund the program after Decision No. 79293 was approved.[58] Since that time, enrollment in APS's Energy Support Program has increased from 76,817 to 84,720 customers (as of the end of February 2026), and the average bill for a participant has decreased from $119.33 in 2023 to $118.04 in 2025 through the addition of a second 60% discount tier. The average discount went from ($41.22) in 2023 to ($56.07) in 2025, which is a 36% increase in the average bill discount.

In total, APS customers spent $56.3 million in 2025 annually to offer a robust discount program for vulnerable customers who need it the most, and to the Company's knowledge, this program provides a higher level of funding than any other utility limited income discount program in the state of Arizona. The increased enrollment and level of financial support provided to customers justifies that the program is working as intended and, therefore, the Company is not seeking additional funding at this time to expand it. This approach seeks to strike the balance between offering appropriate support to qualified participants with managing rate impacts for all customers who fund the discount.

XI. GENERAL SERVICE RATE DESIGN

Q. DID INTERVENING PARTIES PROPOSE CHANGES TO GENERAL SERVICE RATES AS WELL?

A. Yes. The Kroger Co. (Kroger) witness Stephen J. Baron makes recommendations to the energy charges included in the E-32M and E-32L rate schedules, and Mr. Sarver proposes modifications to the General Service Schools discount rider. FEA witness Jessica York proposes a larger increase be applied to the Dusk to Dawn

[58] Wildfire, Direct Testimony of Claire Michael (Mar. 18, 2026) at 17-19.

Streetlighting rate class, and Mr. Pollock proposes changes to the E-34 and E-35 rate classes energy charges based on the service voltage at the premise. Lastly, Staff witness Alexander J. Abramson and Arizona Solar energy Industries Association (AriSEIA) witness Kevin Lucas both propose changes to E-32L Storage Pilot.[59]

Q. PLEASE DISCUSS MR. BARON'S RECOMMENDATIONS.

A. Mr. Baron proposes two changes. First, he states that the kWh component of the delivery charge in the E-32M rate should not be increased, on the basis that delivery charges are driven by demand and not customer usage.[60] Second, he suggests that the E-32L generation energy charge and the E-32M Tier 2 generation energy charge are above production energy costs.[61] He recommends that these charges should not be increased and that the revenue should be recovered through larger increases to the corresponding demand charges instead.[62] Mr. Baron points out that, based on APS's COSS results, higher demand charges could be supported, and lower energy charges could also be supported. [63] However, under his proposal, businesses with a lower load factor would experience a larger increase from a higher demand charge, while those with a higher load factor would benefit from lower energy charges. Other intervenors are advocating for changes in the opposite direction, proposing an increase in energy charges and a decrease in demand charges. APS does not support proposed changes, currently, and maintains that the

[59] Kroger, Direct Testimony of Stephen J. Baron (Mar. 18, 2026) (Baron Direct) at 13-14; Sarver Direct at 19-21; FEA, Direct Testimony of Jessica A. York (Mar. 18, 2026) (York Direct) at 20-23; Pollock Direct at 46-47; Staff, Direct Testimony of Alexander J. Abramson (Mar. 18, 2026) (Abramson Direct) at 7-8; AriSEIA, Direct Testimony of Kevin Lucas (Mar. 18, 2026) (Lucas Direct) at 91.

[60] Baron Direct at 6-8.

[61] *Id.*

[62] *Id.* at 6-7.

[63] *Id.* at 6-8.

Company's proposed rate design strikes the correct balance between energy and demand charges, making continued progress toward alignment with costs.

Q. PLEASE DISCUSS MR. SARVER'S RECOMMENDATIONS.

A. Mr. Sarver proposes that the General Service Schools rate class discount rider be modified from a per kWh discount to a per kW discount.[64] The discount offered to schools is similar in nature to the discount provided to large, aggregated accounts taking service on the E-32 L and E-32 L TOU rates. For these aggregated accounts, there is a volume discount to recognize that, in total, they are a large energy consumer. Changing the design of the school discount rider as proposed by Mr. Sarver would benefit lower energy users with high demand levels at the expense of schools with higher energy consumption that do not have solar installed. Because of this, the Company does not propose adopting Mr. Sarver's change.

Q. PLEASE DISCUSS MS. YORK'S RECOMMENDATIONS.

A. Ms. York proposes larger increases to Residential and Dusk to Dawn rate classes, which are both achieving a level below their respective cost of service.[65] While achieving 100% cost of service is the goal, APS believes that the current proposal makes appropriate progress toward rate and cost parity with elements of the FRAM that will continue toward alignment. As such, Ms. York's proposal is not supported by the Company.

Q. WHAT CHANGES DO STAFF AND ARISEIA RECOMMEND FOR THE E-32 L STORAGE PILOT?

A. Mr. Lucas has proposed modifying the pilot program to include fewer hours and to create additional rates that would apply to a broader customer group based on size.[66] By contrast, Mr. Abramson proposes ending the pilot program.[67]

[64] Sarver Direct at 19-21.
[65] York Direct at 20-23.
[66] Lucas Direct at 91.
[67] Abramson Direct at 2.

APS supports Staff's recommendation. As Mr. Lucas points out, throughout the long history of this pilot program, there have been zero customers enrolled in this rate, despite multiple attempts to redesign the rate and increase adoption through collaboration and engagement with stakeholders.[68] Each iteration has required modifications to APS's billing and metering system to accommodate the changes, yet enrollment has not increased. Today, APS offers General Service customers an alternative program to encourage energy savings and demand shifting, which could include the use of energy storage or other means, through the Flex Solutions program. Through this program, APS compensates customers for three and five hour demand reduction events, which aligns with the request from Mr. Lucas. As such, APS has a more flexible means of accomplishing the same goal as the E-32 L Storage Pilot. Therefore, APS agrees with Staff that it would be appropriate to end the E-32L Storage Pilot program.

Q. DID APS MAKE ANY ADDITIONAL CHANGES TO THE E-32 L RATE?

A. Yes. In the Company's proposed E-32 L rate filed with my Direct Testimony, the delivery demand charges were inadvertently decreased and the generation demand charges increased larger than intended. APS has corrected that issue to align increases to those unbundled components in a similar method as other rate classes.

XII. GROWTH BASED DIRECT ASSIGNMENT

Q. DISCUSS GENERAL FEEDBACK TO THE COMPANY'S GROWTH-BASED DIRECT ASSIGNMENT.

A. Several intervening parties recognize potential risks associated with the current environment and offer general support for APS's proposed allocation changes described in Mr. Moe's Direct Testimony. These changes are intended to address rapid and sustained load growth among large, high load factor customers, such as

[68] Lucas Direct at 79-80.

data centers. Staff witness Dr. Randell M. Johnson offered testimony detailing the magnitude of growth in APS's service territory and the increasing influence on system demand characteristics, which have long-term planning implications. Similarly, Mr. Carpenter expressed support for the Company's XHLF proposal and Dr. McGovern generally supported the direct assignment of generation and fuel costs but cautioned that this protection fails if growth does not materialize.[69] I agree with Dr. McGovern's concern and for this reason the XHLF tariff includes minimum bill thresholds and other financial protections to prevent those costs from being shifted to other customers (Mr. Tetlow and Mr. Bauer, in their Rebuttal Testimonies, provide more detail on these requirements). Dr. McGovern further stresses that there is significant risk that the costs associated with procuring new generation needed to serve growth will be borne by all customer classes. For this reason, Dr. McGovern comments that the updated XHLF rate schedule protects customers by ensuring a linkage between cost-causation and the customer imposing the cost.

Q. DO INTERVENORS COMMENT ON WHETHER A SIMILAR APPROACH SHOULD BE TAKEN WITH TRANSMISSION AND DISTRIBUTION (T&D) COSTS?

A. Yes. Ms. Potter, Western Resource Advocates (WRA) witness Andy Eiden, and Mr. Madsen recommend that distribution and transmission costs be identified and assigned proportionally by the level of incremental demand caused by data centers for those assets.[70] Mr. Madsen agrees with the Company that the unique differences

[69] Carpenter Direct at 9-10; McGovern Direct at 12-13.

[70] Potter Direct at 13-14; RUCO, Direct Testimony of Dustin Madsen, CPA, CDP, CRRA, CPA (CAN), CA (CAN) (Mar. 18, 2026) (Madsen Direct-Rate Design) at 5; WRA, Direct Testimony of Andy Eiden (Mar. 18, 2026) at 16, 47-48.

of data center customers should be addressed through rate structures that reduce risk of unrecovered investments and mitigate cost shifts to other customers.[71]

The Company agrees with these recommendations and believes the line extension and economic feasibility study requirements in Service Schedule 3 adequately addresses distribution-related investments and costs. While APS has not yet had to make significant transmission-related investments for the sole purpose of serving a specific customer or group of customers, the Company recognizes the need for modifications to the allocation of retail transmission costs within the TCA mechanism to address growth-related issues. Docket No. E-00000A-25-0069 provides an opportunity to explore and propose solutions that address these concerns. As such, the Company intends to propose these changes in a future filing.

Q. DO YOU AGREE THAT REQUIRING DATA CENTERS TO TAKE SERVICE UNDER RATE SCHEDULE XHLF IS DISCRIMINATORY?

A. No, I do not. While I am not a lawyer, my understanding is that, to the extent groups of customers present unique shared characteristics impacting the utility company's cost to serve such customers, it is not unreasonably discriminatory to treat them differently. As I discussed in my Direct Testimony, data centers share a number of unique characteristics that bear directly on the utility company's risks and costs to serve them. For this reason, among others, APS's proposed treatment of data centers under the proposed changes to rate schedule XHLF is not discriminatory.

Microsoft witness Dr. Larry Blank claims that XHLF favors certain large load customers over others and opposes APS's proposal to require data centers to take service under XHLF. Dr. Blank claims it would be "discriminatory and would establish a precedent that would allow future discriminatory treatment of other

[71] Madsen Direct-Rate Design at 12, 14-15.

disfavored customers." However, creating facility specific criteria for rate design is not a new practice. In fact, APS has offered rates specifically for agricultural water pumping customers, schools, and houses of worship for several years. It is practical to evaluate customers based on their size and load attributes, and evaluate them as a class in COSSs. As stated earlier, in my Direct Testimony I describe some of these key distinctions for data centers.

Conversely, if APS did not require data centers to take service under rate schedule XHLF, eligible customers could switch between XHLF and E-34 or E-35 (APS's other Extra Large General Service rate schedules) and take advantage of rates that do not reflect costs associated with serving them. This would result in an under recovery of revenue, putting upward pressure on rates for other participants in the XHLF rate class and exacerbate cost shifts.

Q. HAVE UNIQUE TARIFF PROVISIONS SPECIFIC TO DATA CENTER CUSTOMERS BEEN EVALUATED IN OTHER JURISDICTIONS?

A. Yes. Other jurisdictions have addressed similar claims that data center-specific utility tariff provisions are discriminatory and have rejected this argument. For example, in a recent decision by the Public Utilities Commission of Ohio (PUCO), PUCO endorsed an American Electric Power (AEP) Ohio tariff that imposed special tariff provisions for data centers based on their unique characteristics.[72] There, PUCO determined that the unique characteristics of data centers represented differences reasonably impacting the expense or difficulty of performing the same or similar service in different areas or circumstances and, as such, may be reflected in cost recovery variations or differences, which would not be deemed unlawful

[72] *See* Public Utilities Commission of Ohio, Case No. 24-508-EL-ATA (*In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers*), 2025 OHIO PUC LEXIS 766 (Opinion and Order dated July 9, 2025).

nor discriminatory.[73] PUCO also recognized and acknowledged that Idaho, Arkansas and Wyoming have approved data center-tailored proposals to address the unique traits of data center and blockchain customers.[74]

Similarly, California recently adopted AB 222, which added new authorities to the state's Public Utilities Code, providing that the California Public Utilities Commission (CPUC) shall assess costs associated with new loads from data centers and the extent to which those costs result in a cost shift to other electrical corporation customers.[75] The CPUC is then charged with identifying opportunities to prevent or mitigate those shifts in costs.

Q. CAN YOU ADDRESS COMMENTS MADE REGARDING APS'S SUBSCRIPTION MODEL?

A. Yes. First, it is important to mention that there are no costs, expenses, or investments associated with serving potential participants in the Subscription Model being sought for recovery in this case, as discussed further by Mr. Tetlow in his Rebuttal Testimony. This program is still under development, so APS does not have specific terms and conditions that would apply to particular customers that it is proposing at this time. As such, the Company does not propose changes to any Rates, Rate Schedules, or Rate Riders to address any associated program costs. It is important to recognize as well that APS cannot extend service to any

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[73] *Id*. at ¶¶128-131 (PUCO found the following characteristics justified the unique treatment of data centers as opposed to other large general service customers: transmission/resource constraints impacting the ability to serve all customers; driving needs for constructing significant new infrastructure to serve data centers in particular; very high load factors for data centers as compared to other large customers, with loads that cycle periodically; and no ability to hedge based on impacts across different industries).

[74] *Id*. at ¶131.

[75] California Code, Pub. Util. Code § 913.22 (https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=913.22).

customer under this program until it brings forth a specific customer contract for approval by the Commission. At that time, the Commission and stakeholders will have opportunities to scrutinize the specific terms of service for a participating customer. For these reasons, evaluating this under-development program today would be premature and unnecessary.

Mr. Pollock asserts that it is a best practice to adopt large load tariffs that allow customers to procure electricity to meet their speed-to-market need, while also providing terms and conditions that reduce the risk for utilities and insulate existing customers. This is precisely what APS's proposed modifications to rate schedule XHLF, and the growth-based direct assignment allocation, are intended to accomplish. As APS develops its future Subscription Model, it is designing this program to achieve similar goals. Once that program is finalized, and APS has specific terms of service to propose for one or more participating customers, the Commission will engage in a rigorous evaluation process to ensure it accomplishes these goals and fully protects non-participating customers.

Q. IS THE COMPANY SEEKING APPROVAL TO ADOPT MINIMUM BILL OR USAGE THRESHOLDS IN THIS PROCEEDING?

A. No. These terms are already reflected in applicable General Service Rate Schedules. In addition to minimum kW requirements in the XHLF tariff, the Minimum Bill section states, "The bill will not be less than the minimum amount specified in the Customer's service agreement or contract." Similarly, item 5 under the Service Details section of E-35 states "Some customers will have a service agreement or contract that specifies certain provisions of their electric service, such as contract length, minimum and maximum monthly loads, special charges, and other service details." These provisions exist to ensure the Company can properly evaluate costs to serve a customer and require appropriate minimum thresholds to

protect other customers from exposure to those costs should a customer not energize, energize later than expected after the Company has already incurred costs to serve them, or consume less than anticipated. This, therefore, prevents such customers from paying less in rates than the Company incurred in costs to serve, avoiding a cost shift to other customers.

Dr. Blank argues that the Commission must review and approve the Load Commitment Agreements (LCA) and ESA on the basis that revenues collected are customer revenues just like other rates and charges and could potentially provide windfall revenues to APS. These agreements simply reflect the requirements, authorized under governing rate schedules.[76] I agree that these customers pay all Commission-approved rates and charges. For that reason, the Company will reflect the benefit of any associated revenues in the same manner as traditionally billed rates and charges. Every time class level rates are adjusted, both in a general rate case proceeding, or in an annual FRAM update, the revenues generated from minimum payments, termination fees, or other revenues generated from minimum usage levels or other attributes included in an LCA or ESA, will be applied to the respective class as a credit and any rate adjustment made will consider that credit.

I note also that because the minimum thresholds establish the level of capacity or energy that the customer is responsible for, the amount being charged is based on the approved rate schedule under which the customer is enrolled. The minimums simply outline the level of capacity and energy that the customer is asking the Company to procure on their behalf with a commitment to pay a fair portion of those costs, even if they don't end up consuming at that level.

[76] Microsoft, Direct Testimony of Larry Blank, Ph.D. (Mar. 18, 2026) (Blank Direct) at 12-13.

Finally, if each modification to the LCA or ESA required Commission approval, the Company would not have been able to evaluate changing circumstances associated with the current magnitude of high, load factor growth. This would hinder the Company's ability to make appropriate accommodation to protect other customers timely to mitigate from potential unintended consequences.

Q. DO YOU AGREE THAT THE REQUIREMENTS IN APS' LCA ACT AS A "RATE RIDER" THAT SHOULD BE SUBJECT TO EXPLICIT COMMISSION APPROVAL?

A. No. The requirements in the LCA do not reflect any incremental or additional cost recovery obligations on customers than what is contained within currently approved tariff language. Current APS tariffs already authorize APS to enter into service agreements with its largest customers; the XHLF tariff in fact requires that all customers taking service under that rate schedule enter into a service agreement with APS. In each of these cases, the governing tariffs also authorize the imposition of minimum bill and usage thresholds. Financial security and early termination payments, key financial elements of the LCA described in more detail by Mr. Bauer in his Rebuttal Testimony, simply represent agreed upon remedies cost recovery explicitly called out in the tariff. In other words, the LCA does not in any way expand upon what APS is already legally authorized to charge and collect from customers under existing tariffs. For this reason, no separate Commission approval is necessary for these terms in the LCA.

Q. HAVE OTHER UTILITIES ADOPTED CONTRACTUAL MINIMUMS TO PROTECT FROM STRANDED COST RISK AND POTENTIAL COST SHIFTS?

A. Yes. Several other utilities have adopted minimums usage and bill thresholds to address these concerns. Demand minimum charges are the most common, with

utilities such as Consumers Energy Michigan, Indiana Michigan Power, and Evergy Kansas, among several others, all implementing minimum demand charges of between 75% and 85% of contract capacity.[77] In addition, some utilities have also instituted or proposed minimum energy charges alongside minimum demand charges, such as Appalachian Power, who imposes minimum demand charges of 80% of contract capacity as well as minimum energy charges of 60% applying to their large load tariff.[78]

XIII. AG-X PROGRAM

Q. DOES APS OPPOSE NRG ENERGY INC'S (NRG) PROPOSED RESOURCE ADEQUACY CHARGE ASSERTIONS?

A. Yes. NRG witness Dr. Lance D. Kaufman argues that the resource adequacy (RA) charge applicable to AG-X customers should be lower than the unbundled generation demand charge used in Rate Schedule E-34.[79] Dr. Kaufman justifies this position, in part, based on a comparison to demand charges in an agricultural water-pumping rate.[80] APS disagrees with this comparison and the resulting

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[77] *In the matter of the application of Consumers Energy Company for ex parte approval of certain amendments to Rate GPD,* Michigan Case No. U-21859 - https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001Nipc9AAB; *In the Matter of the Verified Petition of Indiana Michigan Power Co. for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.,* Indiana Cause No. 46097 - https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/2b48cf93-d9ee-ef11-be20-001dd80b8c52/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_46097_021925.pdf; *In the Matter of the Application of Evergy Kansas Metro, Inc., et al. for Approval of Large Load Service Rate Plan and Associated Tariffs,* Kansas Docket No. 25-EKME-315-TAR, Order Approving Unanimous Settlement Agreement (Nov. 6, 2025), https://estar.kcc.ks.gov/estar/ViewFile.aspx/25-315_Settlement_Agreement.pdf?Id=f65c8223-c3d3-47a7-b83b-877f318cf355

[78] Appalachian Power Company Schedule L.C.P. - https://www.appalachianpower.com/lib/docs/ratesandtariffs/WestVirginia/ENG_Tariff_Sheets_Eff_11-19-25.pdf

[79] NRG, Direct Testimony of Lance D. Kaufman, Ph.D. (Mar. 18, 2026) (Kaufman Direct) at 6-14.

[80] *Id.* at 13.

conclusion. In Mr. Moe's Rebuttal Testimony, he clarifies that the revenue requirement for AG-X customers, which use APS-provided RA, is significantly higher than portrayed by Dr. Kaufman. In fact, based on APS's COSS results, AG-X RA could support a charge of more than $24/kW-month and for E-34 a charge of more than $23/kW-month could be supported.

In Decision No. 79293, the Commission determined that AG-X customers receive RA service from APS and, therefore, should be assigned production-related costs.[81] The Commission recognized that APS must maintain full backup capacity to ensure system reliability in the event a third-party Generation Service Provider (GSP) fails to deliver generation supplies to APS's service territory. As a result, AG-X customers were provided a clear choice: they may either purchase RA from APS or obtain RA from their GSP.

Accordingly, APS-provided RA is entirely optional. Under this structure, if an AG-X customer elects GSP-provided RA, the customer pays APS zero dollars for RA service as it is provided by their GSP. Dr. Kaufman's argument that APS's RA charge is "too high" fails to account for this fundamental feature of the AG-X design—customers who believe APS's RA charge is uneconomic are free to opt out and rely on their GSP instead.

Q. DID OTHER WITNESSES HAVE PROPOSED CHANGES TO THE AG-X PROGRAM?

A. Yes. Mr. Pollock proposes that the Commission reject APS's proposal to (1) rename the existing reserve capacity charge as the RA charge and (2) increase the

[81] Decision No. 79293 at 254-55.

AG-X management fee to $1.90 per MWh. APS disagrees with both recommendations.[82]

With respect to the reserve capacity charge, APS was expressly authorized in the prior rate case (Decision No. 79293) to use the E-34 unbundled generation charge to recover RA costs from those customers with GSP contracts that do not include RA.[83] APS's proposal in this case does not introduce a new charge or cost recovery mechanism; rather, it simply aligns the name of the charge with its actual purpose—recovering RA costs. In APS's 2022 rate case, Dr. Kaufman proposed to rename the charge to "remove ambiguity and potential confusion.[84]

Regarding the management fee, APS's proposed increase reflects an average adjustment level consistent with the level of increases applied to other rate components to achieve the proposed revenue requirement. There is no cost-based justification for exempting AG-X customers from this increase. Allowing AG-X customers to avoid an otherwise reasonable and broadly applied adjustment would result in unjustified preferential treatment.

For these reasons, APS recommends that both of Mr. Pollock's proposals be rejected.

[82] Pollock Direct at 53-54.
[83] Decision No. 79293 at 332:12-19.
[84] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Prop. for Ratemaking Purposes*, Docket No. E-01345A-22-0144, NRG, Direct Testimony of Lance D. Kaufman (Jun. 15, 2023) at 18:1-2.

XIV. OTHER ADJUSTMENT MECHANISMS

Q. IS THE COMPANY PROPOSING A CHANGE TO THE POWER SUPPLY ADJUSTMENT PLAN OF ADMINISTRATION (PSA POA)?

A. Yes. The Company is adding clarifying language to the embedded cap as it relates to the Fuel and Purchased Power Direct Assignment as discussed in Mr. Moe's Rebuttal Testimony.

Q. DOES APS SUPPORT MR. LUCAS'S PROPOSED CHANGES TO THE VIRTUAL POWER PLANT (VPP) PROGRAMS?

A. While APS appreciates Mr. Lucas's interest in the design and valuation of VPP programs,[85] APS believes the Demand Side Management (DSM) Implementation Plan filing is the appropriate venue to discuss these issues. In that venue, stakeholders and Staff have the opportunity to evaluate each program's cost-effectiveness, operational performance, and customer impacts on a program-by-program basis, including the detailed VPP design changes proposed in the context of the DSM plan.

Q. DOES APS AGREE WITH MR. POLLOCK'S PROPOSED CHANGES TO THE PSA?

A. No. Mr. Pollock proposes that purchased power capacity costs should not be recovered through the PSA but instead be recovered through the SRB) mechanism.[86] APS does not support this proposal for several reasons.

First, purchased power capacity costs are an integral component of APS's power supply portfolio and are appropriately recovered through the PSA, which was designed to recover these costs on a pass-through basis. This means that APS earns no returns or profits from any costs recovered through the PSA. The PSA is

[85] Lucas Direct at 92-93.
[86] Pollock Direct at 62-63.

specifically designed to recover the expenses associated with fuel and purchased power used to serve customers, including capacity-related components of power purchase agreements. Removing purchased power capacity costs from the PSA would undermine the fundamental purpose of this mechanism.

Second, the SRB was not designed to recover purchased power capacity costs. Rather, the SRB was intended to recover capital carrying costs associated with Company-owned qualified generating resources. Purchased power capacity costs, by contrast, are power supply expenses and do not represent capital investment. Using the SRB for such recovery, which includes a number of procedural and stakeholder review mechanisms specifically intended for large APS-owned generation capacity additions, would add substantial regulatory lag to the recovery of critical, and sometimes volatile, purchase power capacity costs. As such, APS's booking of costs for purchased power capacity costs is consistent with historical treatment within the PSA and should not be modified.

Finally, APS is proposing to eliminate the SRB as part of a package of modifications to the FRAM, discussed earlier in this testimony. In the absence of a stand-alone SRB mechanism, Mr. Pollock's proposal is unworkable.

XV. CUSTOMER COMMUNICATIONS

Q. DOES THE COMPANY AGREE WITH THE PROPOSED CHANGES TO RATE CASE RELATED CUSTOMER COMMUNICATIONS?

A. Ms. Potter requests that APS explain to customers how rates can change outside of the rate case through adjustor proceedings.[87] APS presently communicates changes in adjustor rates to customers through a variety of channels, including bill messages and presenting them on the APS website. The customer bill message explains the

[87] Potter Direct at 23-24.

rate impact of each adjustor change, which is provided by rate plan, as well as typical usage level impacts. APS also updates the website, at aps.com/adjustors, each time an adjustor rate changes. Ms. Potter's testimony also requests that additional information be provided to explain how customers on different rate plans may be impacted, including seasonal levels of impact.[88] There could be complications in providing customers with seasonal bill impacts based on the geographic diversity in APS's service territory, as customers in Northern Arizona may have higher winter heating related usage and customers in Central Arizona may consume more in the summer when homes are being cooled.

With that said, the Company does file bill impacts by rate class and season in connection with general rate cases. For example, this data is attached to my Direct Testimony as SFR H-4 and provides this level of detail by kWh bin. A customer could use this information to estimate base rate impacts by season and rate using their own typical levels of consumption during each season for more specific levels of monthly impact. Consistent with peer Arizona electric utilities, rate changes are communicated through centralized webpages that explain the drivers for the increase and present typical monthly bill impacts with any variation in customers' bills attributed to usage.

Q. IS THE COMPANY PROPOSING ANY OTHER CHANGES TO CUSTOMER COMMUNICATIONS?

A. Yes. The Company is proposing to rename the current March 31st off-peak holiday to Farmworker's Day. As the day is currently an off-peak holiday and will remain an off-peak holiday, there is no impact to rates and rate schedules. This change is solely to rename the holiday in the Time Periods section of impacted Rate Schedules.

[88] *Id.*

Q. WHERE CAN CUSTOMERS FIND INFORMATION ON THE AG-X ENROLLMENT PROCESS?

A. Currently, enrollment in the AG-X Rate Rider is being handled consistently with all other available rate options as the program has ample capacity to accommodate new requests. Sections 3 and 4 of the AG-X program guidelines are posted on the Company's website and made available to all interested participants. These sections provide information on how customers can participate in the program.[89] Similarly, APS Key Account Managers are available to discuss with General Service customers opportunities to participate in AG-X or any other Rate Schedule, Rate Rider, or Customer Program.

Dr. Kaufman requests that the program guidelines should clarify how customers can be added to the enrollment waiting list or participate on a first-come, first-served basis.[90] However, as there is currently 93 MW of available capacity within AG-X (as of March 2026), no waiting list is necessary. At this time, only one existing customer is inquiring about potentially expanding the number of currently-participating customer accounts on the program.

XVI. SERVICE SCHEDULES

Q. PLEASE DISCUSS ANY PROPOSED MODIFICATIONS OF SERVICE SCHEDULE 3.

A. Mr. Smith does not agree with the Company's proposed modifications to Service Schedule 3. To be clear, APS is committed to providing safe and reliable service

[89] https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Business/Service-Schedules/AG-X_Program_Guidelines.pdf?sc_lang=es-MX https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Business/Service-Schedules/AG-X_Program_Guidelines.pdf?sc_lang=es-MX.

[90] Kaufman Direct at 2, 16.

to all customers within its Certificate of Convenience and Necessity (CC&N) territory, consistent with Arizona law and its terms and conditions of service.

Historically, Electrical Districts have served residential, small commercial, and irrigation customers within and outside of their district boundaries to achieve their "primary purpose of providing water for irrigation."[91] APS has recently observed that Electrical Districts operating within APS's CC&N territory are now seeking to provide electric service to certain large, high load factor customers, including data centers.

After further review, APS no longer believes this clarification is necessary and is, therefore, withdrawing this proposed modification from this rate case (*see* Attachment JEH-06RB and JEH-07RB). As with any other similarly situated customer, large, high load factor customers requesting to change service from an Electrical District to APS will need to comply with the Company's terms and conditions of service, including the process established in APS's Large Customer Project Queue.

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO THE PROPOSED LANGUAGE IN SERVICE SCHEDULE 1 IN RESPONSE TO STAFF'S CONCERNS REGARDING SUBSECTION 1.1(I)?

A. Yes. Staff witness Mr. Abramson proposed revisions intended to protect tenants or subletters who paid their share of electric service costs to the previous account holder but were unaware that the full balance was not paid to APS.[92] The Company agrees that such circumstances warrant clarification to avoid unintended outcomes

[91] *Hohokam Irrigation & Drainage Dist. v. Ariz. Pub. Serv. Co.*, 204 Ariz. 394, 400 (2003).

[92] Abramson Direct at 4.

and recommends some slight adjustments to ensure the effective and consistent administration of the rule.

APS notes that its proposed language was not intended to hold an applicant responsible for a delinquent balance beyond the period during which the applicant resided at the premises or received the benefit of service without payment to APS. Rather, the intent of subsection 1.1(I) is to ensure that individuals who received electric service and did not make payment to APS, are not able to avoid responsibility for those amounts. The currently proposed language by Mr. Abramson states the customer will not be held responsible for the past due balance incurred "if [the customer] can either show that they paid a proportion of its amount for service provided by APS." This leads to potential difficulties in administration as there can be disputes on what "showing" may include.

To address Staff's concern while maintaining the principle on which APS and Staff agree, the Company proposes the following clarifying revisions to Service Schedule 1 (*see* Attachments JEH-08RB and JEH-09RB):

> "(I) The Applicant previously resided at or benefited from the same class of service at the Applicant's Premises during the period the outstanding balance was incurred, and the Applicant is unwilling to make arrangements with APS for payment.
>
> i. Applicants for residential service may demonstrate that they are not responsible for all or a portion of the prior balance associated with the Applicant's Premises by demonstrating, to APS's reasonable satisfaction, that the Applicant paid their proportional share of the balance owed to APS for electric

service during the period they resided at the Applicant's Premises."

This clarification ensures that applicants are only held responsible for service from which they received benefit, while also providing a reasonable mechanism for tenants or subletters to demonstrate that they satisfied their share of the prior balance. At the same time, it preserves APS's ability to recover unpaid amounts for service rendered.

XVII. PRO FORMA ADJUSTMENTS TO TEST YEAR REVENUE

Q. DO YOU AGREE THAT CRISIS BILL ASSISTANCE DOLLARS ARE ALREADY ALLOCATED IN RATE DESIGN?

A. Mr. Smith removes the $2.5 million reduction to operating income shown on column 53 of SFR C-2 on the basis that it is already allocated in rates.[93] Since the Company proposes to maintain the previously approved level of funding in rates to support this program, that would be true under normal circumstances. However, in preparation of this filing, it was discovered that the dollars booked to fund Crisis Bill Assistance are treated as a below the line expense, which means that, absent a pro forma adjustment, those costs are not included in unadjusted income statement expenses. Because the costs associated with Crisis Bill Assistance were not actually booked as an above the line operating expense, even though funding in rates was approved by the Commission in Decision No. 79293,[94] APS has not received adequate cost recovery for these program costs. APS, therefore, does not propose to recover lost revenue from prior years that the program was funded, instead proposing to leave funding at the current level which requires a pro forma

[93] Staff, Direct Testimony of Ralph C. Smith (Mar. 2, 2026) at 80-81.

[94] Decision No. 79293 at 439 ("APS's Crisis Bill Assistance Program shall be retained with an annual budget of $2.5 million.").

adjustment to reflect the absence of recognition for these Commission-approved costs within APS's Test Year income statement.

Q. PLEASE FURTHER DISCUSS THE AUTOPAY CREDIT REMOVAL PROPOSAL TO CLARIFY WHY THE ADJUSTMENT IS NO LONGER NECESSARY.

A. When the AutoPay credit was first introduced nearly 20 years ago, a large portion of customers were still paying their bills by paper check as electronic payment options were limited. For this reason, incentives were used to encourage customers to move away from higher cost channels to the lower cost AutoPay. Over the past 20 years, electronic payment options have grown in both options (beyond AutoPay) and customer adoption – and are now the norm for customers. Therefore, incentives are not required to drive adoption. Over 90% of payments are now remitted through electronic channels. That means many customers signing up for AutoPay are doing so from another electronic payment method (like online bill pay or a banking app). Transitions from one electronic method (already a relatively lower cost payment channel) to another do not reduce processing costs to the same degree that transitions from paper check payments to electronic payments do (*see* Figure 7).

Figure 7. Payment Method Costs

Payment type	Detail	APS Average Cost Per Transaction
Walk Up locations	In-person customer payments at locations statewide (e.g., grocery store, convenience store, kiosks, etc.)	$0.04
Paper Checks	Customer pays with a physical, paper check that must be mailed, processed, and deposited	$0.42
Electronic Payments (EDI)	Payments made via Electronic Data Interchange - typically for large commercial accounts	$0.09
Electronic Payments (Checking/Savings Account)	Payment made through APS website or IVR directly from customer bank account	$0.07
Electronic Payments (AutoPay)	Customer authorizes APS to pull funds directly from their bank account	$0.02
Electronic Payments (Bank bill pay)	Customer pays APS bill via their bank's app or website	$0.02
Electronic Payments (debit card, credit card, Apple Pay, PayPal, Venmo, Google Pay)	Payments made electronically through APS website or IVR	$0.00

Q. ARE THERE CORRECTIONS TO THE AUTOPAY AND BASE REVENUE ANNUALIZATION IMPACTS DESCRIBED IN YOUR DIRECT TESTIMONY?

A. Yes. On page 36, line 19 of my Direct Testimony, I discuss the base revenue annualization adjustment by describing it as a decrease to operating income, when it should have been described as an increase to operating income to align with the pro forma adjustment impact. Similarly, on page 39 of my Direct Testimony, I describe the AutoPay credit removal pro forma adjustment on lines 17 and 18 accurately as an increase to operating income. However, on line 19, this adjustment is erroneously described as a decrease. For clarity, the pro forma adjustments

reflected in SFR C-2 columns 20 and 36 are correct, so there is no financial impact associated with these narrative corrections.

Q. PLEASE DESCRIBE ANY REBUTTAL UPDATES MADE TO PRO FORMA ADJUSTMENTS YOU SPONSOR.

A. To reflect the updated Rebuttal revenue requirement, the following pro forma adjustment change was made:

- Amortize Limited Income Discount Accumulation was updated from $10.757 million to $15.953 million in pre-tax operating income reduction.

XVIII. MISCELLANEOUS ITEMS

Q. DOES APS HAVE ANY CHANGES TO ITS SERVICE SCHEDULE 1 PROPOSAL?

A. Yes. APS withdraws the previously proposed Service Schedule 1 modification to Section 5.1, Payment of Bills, related to Discontinuance of Service. The proposed revision would have required customers to provide a minimum of three working days' notice prior to disconnecting service and would have imposed a specific prior written notice requirement on non-residential customers. Withdrawal of this recommendation is warranted due to further review of the proposed change, which identified meaningful impacts on customers, as well as substantial administrative and operational burdens.

Q. ARE YOU PROVIDING ADDITIONAL INFORMATION REQUESTED BY CHAIRMAN MYERS?

A. Yes. Chairman Myers issued two letters in this docket requesting more information regarding various topics discussed in APS's rate case Application. The Company's responses are included as Attachments JEH-10RB and JEH-11RB to my Rebuttal Testimony.

XIX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-1
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDED DECEMBER 31, 2024 ADJUSTED

		Base Revenues in the Test Year (a)		Proposed Increase (a)					
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	
Line No.	Customer Classification	Present Rates (b) [1,2] ($000)	Proposed Rates (c) [2] ($000)	Change ($000) (B) - (A)	% (C) / (A)	Adjustor Transfers [3] ($000)	Net Change ($000) (C) - (E)	Net Increase [4] % (F) / (A)	Line No.
1.	Residential	$ 2,152,227	$ 2,523,056	$ 370,828	17.23%	$ 40,147	$ 330,681	15.36%	1.
2.	General Service	1,924,927	2,237,262	312,335	16.23%	40,885	271,450	14.10%	2.
3.	Irrigation/Water Pumping	36,363	42,448	6,085	16.73%	1,764	4,321	11.88%	3.
4.	Outdoor Lighting	20,417	23,838	3,421	16.75%	104	3,317	16.24%	4.
5.	Dusk to Dawn Lighting Service	9,295	10,853	1,558	16.76%	18	1,540	16.57%	5.
6.	Total Sales to Ultimate Retail Customers	$ 4,143,229	$ 4,837,456	$ 694,227	16.76%	$ 82,918	$ 611,309	14.75% (d)	6.

NOTES TO SCHEDULE:

1) Base Revenues under Present Rates reflect adjusted test year revenues including applicable proforma adjustments.
2) Present and Proposed Rates base revenues include transmission costs based on OATT rates effective during Test Year.
3) Test Year adjustor revenue, less revenue credits and all other non-jurisdictional ACC revenues, transferred to base rates.
4) Average base bill impact net of adjustor transfers.

Supporting Schedules:
(a) H-2
(b) G-1
(c) G-2

Recap Schedules:
(d) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-2
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDED DECEMBER 31, 2024 ADJUSTED

Line No.	(A) Customer Classification and Current Rate Designation	(B) Average Number of Customers	(C) Adjusted MWh [2] Sales	(D) Average Annual kWh Usage per Customer	(E) Base Revenues under Present Rates [1] ($000)	(F) Proposed Rate Designation	(G) Proposed Revenue Base Revenues ($000)	(H) Change - Base Rates ($000) (G) - (E)	(I) % (H) / (E)	(J) Net Increase With Adjustor Transfers ($000)	(K) % (J) / (E)	(L) Adjustor ($000)	Line No.
1	Residential												1
2	R-1 S	274,172	1,544,024	5,632	$ 234,004	R-1 S	$ 279,100	$ 45,096	19.27%	$ 40,909	17.48%	$ 4,187	2
3	R-1 M	140,646	1,328,500	9,446	206,521	R-1 M	241,121	34,600	16.75%	31,043	15.03%	3,558	3
4	R-1 L	64,807	1,077,499	16,626	174,782	R-1 L	201,139	26,357	15.08%	23,517	13.45%	2,840	4
5	RTOUE47 Non-Solar	254,932	3,124,324	12,256	478,297	RTOUE47 Non-Solar	558,376	80,079	16.74%	71,134	14.87%	8,945	5
6	R-2 Non-Solar	53,973	751,684	13,927	108,682	R-2 Non-Solar	126,890	18,208	16.75%	15,722	14.47%	2,486	6
7	R3-47 Non-Solar	295,695	5,275,447	17,841	703,914	R3-47 Non-Solar	821,882	117,968	16.76%	104,134	14.79%	13,834	7
8	REV-47 Non-Solar	224	6,576	29,359	888	REV-47 Non-Solar	1,037	149	16.76%	145	16.28%	4	8
9	Subtotal	1,084,449	13,108,055	12,087	$ 1,907,089	Subtotal	$ 2,229,545	$ 322,456	16.91%	$ 286,602	15.03%	$ 35,855	9
10	RTOUE47 Solar	75,216	738,726	9,821	$ 122,055	RTOUE47 Solar	$ 145,551	$ 23,497	19.25%	$ 21,528	17.64%	$ 1,969	10
11	R-2 Solar	8,638	94,703	10,963	15,550	R-2 Solar	18,546	2,996	19.27%	2,649	17.03%	347	11
12	R3-47 Solar	14,863	230,105	15,482	33,839	R3-47 Solar	40,359	6,520	19.27%	5,934	17.54%	586	12
13	REV-47 Solar	93	2,343	25,197	310	REV-47 Solar	374	64	20.66%	50	16.25%	14	13
14	E-12	28,958	116,834	4,035	21,834	E-12	26,401	4,567	20.92%	4,236	19.40%	332	14
15	ET-1	9,268	68,555	7,397	9,680	ET-1	11,704	2,024	20.91%	1,832	18.92%	193	15
16	ET-2	33,212	278,775	8,394	38,511	ET-2	46,574	8,064	20.94%	7,285	18.92%	779	16
17	ECT-1R	206	3,034	14,728	526	ECT-1R	624	98	18.61%	86	16.38%	12	17
18	ECT-2	1,217	16,619	13,656	2,834	ECT-2	3,377	543	19.16%	480	16.95%	62	18
19	Subtotal	171,671	1,549,694	9,027	$ 245,139	Subtotal	$ 293,511	$ 48,372	19.73%	$ 44,079	17.98%	$ 4,293	19
20	Total Residential	1,256,120	14,657,749	11,669	$ 2,152,227	Total Residential	$ 2,523,056	$ 370,828	17.23%	$ 330,681	15.36%	$ 40,147	20

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-2
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDED DECEMBER 31, 2024 ADJUSTED

Line No.	(A) Customer Classification and Current Rate Designation	(B) Average Number of Customers	(C) Adjusted MWh [2] Sales	(D) Average Annual kWh Usage per Customer	(E) Base Revenues under Present Rates[1] ($000)	(F) Proposed Rate Designation	(G) Proposed Revenue Base Revenues ($000)	(H) Change - Base Rates ($000)	(I) %	(J) Net Increase With Adjustor Transfers ($000)	(K) %	(L) Adjustor ($000)	Line No.
21	General Service											-	21
22	E-20	367	31,041	84,657	$ 4,358	E-20	$ 5,088	$ 730	16.76%	$ 547	12.54%	$ 184	22
23	E-30	3,885	4,055	1,044	1,243	E-30	1,358	115	9.22%	110	8.88%	4	23
24	E-32 XS	109,163	1,701,112	15,583	283,514	E-32 XS	309,625	26,111	9.21%	19,072	6.73%	7,039	24
25	E-32 XSD	1,455	50,738	34,874	6,997	E-32 XSD	7,642	645	9.22%	511	7.30%	134	25
26	E-32 S	19,499	2,638,104	135,294	373,012	E-32 S	407,409	34,397	9.22%	23,868	6.40%	10,529	26
27	E-32 M	4,427	3,423,163	773,261	406,115	E-32 M	443,565	37,450	9.22%	25,518	6.28%	11,932	27
28	E-32M AG-X	25	48,335	1,933,387	6,708	E-32M AG-X	7,994	1,286	19.17%	1,286	19.17%	-	28
29	E-32 L	845	2,897,640	3,427,469	299,967	E-32 L	350,332	50,364	16.79%	47,146	15.72%	3,218	29
30	E-32L AG-X	21	119,946	5,622,488	14,075	E-32L AG-X	17,025	2,950	20.96%	2,950	20.96%	-	30
31	E-32TOU XS	822	24,107	29,324	3,708	E-32TOU XS	4,050	342	9.22%	270	7.27%	72	31
32	E-32TOUS	150	29,566	197,000	4,233	E-32TOUS	4,624	390	9.22%	292	6.89%	99	32
33	E-32TOUM	119	123,212	1,031,786	14,678	E-32TOUM	16,031	1,353	9.22%	963	6.56%	390	33
34	E-32TOUL	94	382,536	4,080,385	40,802	E-32TOUL	47,638	6,837	16.76%	6,470	15.86%	367	34
35	E-34	26	1,073,758	41,970,986	97,137	E-34	117,360	18,991	19.31%	17,964	18.26%	1,028	35
36	E-34 AG-X	1	11,589	13,907,256	1,232	E-34 AG-X	-	-				0	36
37	E-35	44	2,085,255	47,302,560	161,669	E-35	208,741	47,072	29.12%	44,391	27.46%	2,681	37
38	E-35 AG-X	2	578,551	289,275,666	41,253	E-35 AG-X	52,979	11,727	28.43%	11,727	28.43%	-	38
39	XHLF	11	2,014,787	183,162,496	135,145	XHLF	202,336	67,191	49.72%	65,098	48.17%	2,092	39
40	GS-SchM	278	137,783	496,368	19,391	GS-SchM	22,314	2,924	15.08%	2,198	11.33%	726	40
41	GS-SchL	54	80,209	1,496,896	9,690	GS-SchL	11,152	1,461	15.08%	1,072	11.06%	390	41
42	Subtotal	141,287	17,455,488	123,546	$ 1,924,927	Subtotal	$ 2,237,262	$ 312,335	16.23%	$ 271,451	14.10%	$ 40,885	42

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE H-2
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDED DECEMBER 31, 2024 ADJUSTED

Line No.	(A) Customer Classification and Current Rate Designation	(B) Average Number of Customers	(C) Adjusted MWh [2] Sales	(D) Average Annual kWh Usage per Customer	(E) Base Revenues under Present Rates [1] ($000)	(F) Proposed Rate Designation	Proposed Revenue (G) Base Revenues ($000)	(H) Change - Base Rates ($000)	(I) %	(J) Net Increase With Adjustor Transfers ($000)	(K) %	(L) Adjustor ($000)	Line No.
	Irrigation/Municipal					Irrigation/Municipal							
43	E-221	1,242	332,852	268,051	$ 36,256	E-221	$ 42,331	$ 6,075	16.76%	$ 4,315	11.90%	$ 1,760	43
44	E-221 AG	6	999	164,219	107	E-221 AG	117	10	9.18%	6	5.76%	4	44
45	Subtotal	1,248	333,851	267,545	$ 36,363	Subtotal	$ 42,448	$ 6,085	16.73%	$ 4,321	11.88%	$ 1,764	45
46	Outdoor Lighting					Outdoor Lighting							46
47	E-58	761	20,164	26,511	$ 9,347	E-58	$ 10,863	$ 1,516	16.22%	$ 1,495	16.00%	$ 20	47
48	E-59	416	57,679	138,763	9,577	E-59	11,224	1,647	17.20%	1,582	16.52%	66	48
49	E-67	151	6,672	44,210	417	E-67	488	72	17.25%	64	15.47%	7	49
50	Contract 12	43	16,046	371,006	1,077	Contract 12	1,262	186	17.24%	175	16.30%	10	50
51	Subtotal	1,370	100,561	73,380	$ 20,417	Subtotal	$ 23,838	$ 3,421	16.75%	$ 3,317	16.25%	$ 104	51
52	E-47 [3]	-	17,570	-	$ 9,295	E-47 [3]	$ 10,853	$ 1,558	16.76%	$ 1,540	16.57%	$ 18	52
53	Total Retail (a)	1,400,026	32,565,219	23,260	$ 4,143,229		$ 4,837,456	$ 694,227	16.76%	$ 611,309	14.75%	$ 82,918	53

1. Base Revenues under Present Rates reflect adjusted test year revenues based on rates established in Decision No. 79293.
2. MWh and sales excludes revenue credits. MWh with revenue credits = 32,672,449
3. Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.

Additional Notes
Rider rate schedules are included in the "Parent" rate schedules listed on schedule H-2 as applicable.
Riders include: E-3, E-4, CPP-RES, PPR, CPP-GS, GPS-1, GPS-2, GPS-3, E-56, E-56 R and SGSP.
Rate Schedule E-36 is not included as proposed price changes are market-related.
Transmission revenues based on OATT charges effective during Test Year.

Supporting Schedules:
N/A

Recap Schedules:
(a) H-1

NOTE: There may be variances in displayed values due to rounding.

Formula Rate Adjustment Mechanism
Plan of Administration

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1. General Description

This document describes the Plan of Administration (POA) for Arizona Public Service Company's (APS or Company) Formula Rate Adjustment Mechanism (FRAM) and Formula Rate Adjustment Schedule (Schedule FRA-1). As authorized by the Arizona Corporation Commission (ACC or Commission) in Decision No. XXXXX (DATE), the FRAM provides for an annual rate adjustment for base rates through Schedule FRA-1 using a Commission-approved formula, which recovers costs for serving electric retail service, excluding costs recovered through the Company's other approved adjustment mechanisms. Schedule FRA-1 is applicable to all Standard Offer customers.

Unless otherwise defined in Section 2, Definitions, capitalized terms have the meaning provided in the body of this POA.

2. Definitions

Annual Update – The Annual Revenue Requirement (ARR) applicable under the Formula Rate Adjustor (FRA) calculated through the Formula Rate Adjustment Mechanism (FRAM) for the upcoming Rate Effective Year. The filing will be based on APS's most recently filed Federal Energy Regulatory Commission (FERC) Form No. 1, using Historical Test Year costs, revenues, and other financial information, with certain pro forma adjustments necessary to annualize base revenues net of base fuel as applicable, interest synchronization and tax normalization, account for crisis bill spending, or adjustments related to surcharges and explicit items removed or otherwise adjusted in the Company's most recently approved rate case applicable to the evaluation year. The Annual Update filing will also include an overview of specific cost drivers and major capital investments impacting each annual reset.

Authorized Rate of Return – The ROE and capital structure authorized in the most recent rate case, adjusted for fair value increment, with an updated cost of debt for the Historical Test Year, adjusted annually until the conclusion of the Company's next general rate case.

Earned Return on Equity (ROE) – APS's earned return on equity percentage is calculated by dividing the operating income less synchronized interest by the equity weighted Historical Test Year Rate Base original cost rate base (OCRB). The equity weighting is determined by the capital structure authorized in APS's most recent rate case.

Earnings Test – Comparison of the Historical Test Year Earned ROE with the ROE Deadband.

Filing Date – The date on which APS files an Annual Update to determine the ARR for the next FRA reset.

Historical Test Year – The twelve (12) month period ended December 31 of the calendar year immediately preceding the filing of the Annual Update.

Rate Effective Year – December 1 following the Filing Date of the Annual Update through November 30 of the subsequent calendar year.

Revenue Requirement Index – An index based on each cost of service class revenues during the Historical Test Year compared to its revenue requirement, which will be used in each Annual Update as a guide to help move the classes toward recovering their cost of service and to minimize cost shifts.

ROE Deadband – The ROE authorized in the Company's most recent rate case, adjusted for fair value increment, plus +/- 0.40%. When the earnings test falls within the ROE Deadband the company will not adjust the FRA.

3. Annual Update

APS will file the calculated Annual Update with true-ups, a reset of Schedule FRA-1, and all compliance schedules with the Commission annually by July 31. APS will also publish the application on the Company's website by July 31. On the day of the filing, the Company will provide notice in the last approved rate case docket of having posted its Annual Update, noting where it can be accessed and providing the dates for the Information Exchange and Informal Challenge Period as described in Section 6 below. The notice will also include details for the annual Interested Party Meeting.

The Annual Revenue Requirement applicable under Schedule FRA-1 shall be calculated in Attachment 1 of the FRAM. This calculation produces the Annual Update for the upcoming Rate Effective Year. The Annual Update will be based on: (1) a Historical Test Year utilizing FERC Form No. 1 and supporting data, (2) actual net plant additions for the six (6) month period

following the Historical Test Year, and (3) any true-ups related to the challenge period from the prior year's filing.

The FRAM is premised upon the following predicates (i) - (iv) (the Fundamental Predicates):

(i) FERC's Uniform System of Accounts (USoA), as adopted by the Commission in R14-2-212(G);
(ii) Commission filing requirements, as applicable;
(iii) Commission decisions establishing generally applicable rate making policies, accounting directives and precedents; and
(iv) APS's accounting policies, practices and procedures.

Changes to the Fundamental Predicates that require a change to the FRAM will be submitted by APS to the Commission for review and approval.

Any Interested Party that disagrees with the application of the FRAM due to a change in one or more of the Fundamental Predicates shall raise the matter with APS in accordance with the informal challenge procedures identified in Section 6 below. If Informal Challenges to the application of the FRAM for the current Annual Update are not resolved by August 31, any Interested Party shall have the right to submit a Formal Challenge as described in Section 6.B.

The Annual Update for the Rate Effective Year shall:

(i) Be provided in both a Portable Document Format (PDF) and Microsoft Excel file format with all formulas and links intact, where possible;
(ii) To the extent specified in Schedule FRA-1, be based upon the FRAM's Attachments 1, 2, 3, and data supported by APS's Standard Filing Requirements (SFRs) B-1, B-2, B-5, C-1, C-2, C-3, D-1, E-1, E-2 and other relevant data schedules for the most recent historical calendar year, along with APS's financial records consistent with the Uniform System of Accounts (USoA) and FERC accounting policies;
(iii) To the extent specified in the FRAM or through Information Exchange pursuant to Section 5, provide supporting documentation or workpapers for data not otherwise available in the above SFRs and schedules that are used in the FRAM;
(iv) Provide notice of changes in APS's accounting policies and practices from those in effect for the calendar year upon which the immediately preceding Annual Update was based (Accounting Changes);
(v) Disclose any Accounting Changes or adjustments that affect inputs to the FRAM calculations;
(vi) Identify items included in the FRAM calculations at an amount other than on a historical cost basis (e.g., fair value adjustments, projected plant);
(vii) Identify any reorganization or merger transaction and explain the effect of the accounting for such transactions on inputs to the FRAM;

(viii) Make note of any aspects of the FRAM or its inputs that are the subject of an ongoing dispute under the Challenge Procedures in Section 6;

(ix) To the extent Accounting Changes and other matters affect APS's inputs to its FRAM, provide a narrative explanation of the individual impact of those items on charges billed under the FRAM;

(x) Be subject to review and challenge, in accordance with the procedures set forth in this FRAM POA, as to whether the input data are properly reflected, and as to the accuracy of the data and the consistency with the FRAM of the changes shown in the Annual Update;

(xi) Include the costs of new "prudently invested" plant placed into service that are used and useful for APS customers consistent with Arizona Administrative Code ("A.A.C.") R14-2-103(A)(3)(l); and

(xii) Not seek to modify the FRAM and shall not be subject to challenge by seeking to modify the FRAM (i.e., all such modifications to the FRAM, including the items specified in Section 3, will require, as applicable, a decision by the Commission).

The following FRAM inputs from APS's most recent general rate case will be used to calculate the Annual Update and the Earnings Test, and will not be revised or updated until such revision is approved by the Commission:

(i) return on equity;
(ii) capital structure;
(iii) cash working capital factor; and
(iv) depreciation and amortization rates.

All data provided pursuant to and in accordance with the procedures set forth in this document may be used in any challenge to the Annual Update of the FRAM.

4. Determination of Schedule FRA-1 Adjustor Rate

Schedule FRA-1 shall be based on the FRAM Annual Update, utilizing an Earnings Test as calculated in Attachment 1 to determine the amount of excess or deficient revenues for the Historical Test Year in conjunction with the established ROE Deadband. If the Earned ROE falls within the ROE Deadband, no change will be made to Schedule FRA-1 and the prior approved adjustor rate will carry over to the current Rate Effective Year. If the Earned ROE is outside of the ROE Deadband, then the ARR as calculated in Attachment 1 will reflect the change in revenues needed to align with the authorized ROE. APS will calculate any percentage change to base rates in Attachment 3. Any such change will be reflected in Schedule FRA-1 and will be applied to the customer's monthly bill over a twelve-month period. The Commission shall take action to approve the FRAM rate reset by no later than December 1 of each year and, unless the Commission has otherwise acted on the Annual Update by December 1, the FRAM rate reset shall be effective with the first December billing cycle, and will not be prorated.

5. Annual Update Information Exchange Procedures

Each Annual Update shall be subject to the following review procedures: (Annual Update Procedures):

(i) Interested Party Meeting (Meeting): Each year APS shall organize and hold a meeting among Interested Parties during which APS shall present details about its Annual Update. The Meeting shall provide Interested Parties the chance to seek information and clarifications from APS about the Annual Update and shall take place on or before August 5, or in any event, no later than (5) days after the Filing Date. Notice of the Meeting, including the time, date, location and how to request remote access information shall be posted on an APS website, posted in APS's last approved rate case docket, and distributed via email notice (or other written notice if email is not available for certain parties) to the parties of record in APS's last approved rate case.

(ii) Information Exchange Period: Interested Parties shall have until August 12 to serve data requests as part of the Informal Information Exchange (Informal Information Exchange Period). For Informal Challenges that APS and the Parties were unable to resolve, Parties shall have until September 22 to serve data requests as part of the Formal Information Exchange (Formal Information Exchange Period). Data requests shall be limited to what is necessary to determine:

a) if APS has properly applied the FRAM and procedures in Schedule FRA-1; and
b) that the input data are properly recorded, to verify the accuracy of the costs and expenditures included for recovery in the Annual Update (including with respect to the prudence of such costs or expenditures), and as to the accuracy of the data and consistency with the FRAM of the charges shown in the Annual Update; or
the effect of any change to the underlying Schedules, USoA or the FERC Form No. 1.

Data requests shall not solicit information concerning costs or allocations where the cost or allocation method has previously been approved or accepted by the Commission, except that such data requests shall be permitted if they seek to determine if there has been a material change in circumstances, Accounting Change or pursuant to discovery of a calculation error.

APS shall make a good faith effort to respond to data requests served as part of the Information Exchange Period within ten (10) business days of receipt of such requests and must respond to all data requests served as part of the Informal Information Exchange by August 26 and by October 6 for all data requests served as part of the Formal Information Exchange.

APS shall, upon request, make all information, requests, and APS's responses to data requests available to Interested Parties — except when such responses to information requests include confidential or proprietary information of APS or a third-party. In such

cases, the information will be made available only after the Interested Party executes an appropriate confidentiality or protective agreement with APS.

Any changes or adjustments to the Annual Update resulting from the Informal Information Exchange Period that are agreed to by APS will be posted on an APS site on September 1, and later filed with the Commission by September 8 (the "Adjusted Annual Update"). The Adjusted Annual Update will be the basis of the current Effective Year FRAM rate adjustment, subject to approval by the Commission.

6. Challenge Procedures

A. Informal Challenges

Informal Challenges shall be subject to the procedures and limitations in this Section.

Objections involving Fundamental Predicates are limited solely to adjustments or revisions as to the content of the above specified Fundamental Predicates that may produce material consequences for the application of the FRAM. Objections involving Fundamental Predicates shall not be pursued in order to achieve other revisions to the FRAM as provided for in Decision No. XXX dated XXX.

Interested Parties may raise an Informal Challenge by August 19. To raise an Informal Challenge, Parties must send an email to APS at ArizonaPublicServiceRegulatoryDepartment@apsc.com, or as otherwise agreed to by the APS and the Interested Parties, specifying the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support the challenge. APS shall post all Informal Challenges received from Interested Parties, along with APS's responses to such Informal Challenges on the Company's website. However, if any Informal Challenges or response includes confidential or proprietary information of APS or third-parties, such information will not be publicly posted but will be made available to requesting Interested Parties pursuant to a confidentiality or protective agreement to be executed by APS and the requesting Interested Party. APS shall respond to all Informal Challenges by August 26.

To the extent APS and Interested Party(ies) are unable to resolve disputes related to Informal Challenges by August 31, APS or Interested Party(ies) may participate in the Formal Information Exchange described in Section 5 and/or file a Formal Challenge with the Commission in accordance with the procedures in Section 6.B., Formal Challenges.

B. Formal Challenges

Formal Challenges shall be subject to the procedures and limitations set forth in this section.

An Interested Party may file a Formal Challenge with the Commission once the Informal Challenge Period has been completed and the Adjusted Annual Update has been posted, which

shall be posted on the APS website by September 1 and then filed by APS with the Commission by September 8. Interested Parties shall have until September 22 to file a Formal Challenge. APS shall respond to all Formal Challenges by October 6.

A Formal Challenge shall satisfy the following requirements:

(i) Clearly identify the action or inaction which is alleged to violate this plan of administration as approved in Decision No. XXXXX;

(ii) Explain how the action or inaction violates this plan of administration as approved in Decision No. XXXXX;

(iii) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the Interested Party(ies) filing the Formal Challenge, including, but not limited to: (a) the extent or effect of an Accounting Change; (b) whether the Annual Update fails to include data properly recorded in accordance with these protocols; (c) the proper application of the Formula Rate and procedures in these protocols; (d) the accuracy of data and consistency with the FRAM of the charges shown in the Annual Update; (e) the accuracy of actual costs and expenditures; (f) the effect of any change to the Fundamental Predicates.; or (g) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate (e.g., assessing the prudence of any costs or expenditures included within the Annual Update);

(iv) Make a good faith effort to quantify the financial impact or burden (if any) created for the Interested Party filing the Formal Challenge as a result of the action or inaction;

(v) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(vi) State the specific relief or remedy requested, and the basis for that relief;

(vii) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing Interested Party, including, but not limited to, contracts and affidavits; and

(viii) State whether the Interested Party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge and describe the outcome of the Informal Challenge.

Any Interested Party filing a Formal Challenge must serve a copy of the Formal Challenge to APS. Service to APS must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail, express delivery, or messenger. The Interested Party filing the Formal Challenge shall serve the individual listed as the contact person on APS's Adjusted Annual Update filing required under Section 5 of these protocols.

C. Challenge Restrictions and Formal Hearings

Informal and Formal Challenges, except those related to Accounting Changes or Fundamental Predicates, are not intended to serve as a means of pursuing other changes to the Formula Rate.

Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (i) the extent or effect of an Accounting Change; (ii) whether the Annual Update fails to include data properly recorded in accordance with these protocols; (iii) the proper application of the Formula Rate and procedures in these protocols; (iv) to determine the prudence of the costs and expenditures included for recovery in the Annual Update; (v) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update; (vi) the accuracy of actual costs and expenditures; or (vii) the effect of any change to the Fundamental Predicates.

In any proceeding initiated by the Commission concerning the Annual Update or in response to a Formal Challenge, APS shall bear the burden of proving that it has reasonably applied the terms of the Formula Rate, including the applicable procedures in these protocols, in that year's Annual Update. Nothing herein is intended to alter the burdens otherwise applied to prudence with respect to A.A.C. R14-2-103(A)(3)(l).

The Commission shall issue a final decision before December 1, absent Commission action by December 1, the Annual Update shall take effect automatically with the first December billing cycle. Staff may commence analysis once the Adjusted Annual Update is posted on the Company extranet site. The Commission's evaluation of the Adjusted Annual Update must include: a current finding of fair value by supplementing and updating the fair value determination from the previous rate case using data contained within the Annual Update filing.

Except as specifically provided, nothing herein shall be deemed to limit in any way the right of APS to file a general rate case to seek to change the FRAM or any of its inputs (including, but not limited to, the rate of return).

Challenges, Rate Effective Date, and Commission Decision Timeline

Action	Deadline
ACC filing/publication of Annual Update; Informal Information Exchange Period and Informal Challenges begin	July 31
Annual Interested Parties Meeting	August 5
Last Day to Serve Data Requests as Part of the Informal Information Exchange	August 12
Last Day to Submit Informal Challenges	August 19
Last Day for Company to Respond to 1) Data Requests Served as Part of the Informal Information Exchange, and 2) Informal Challenges	August 26
Informal Challenge Resolution Deadline	August 31
Adjusted Annual Update Posted	September 1
ACC Filing/Publication of Adjusted Annual Update	September 8

Last Day to 1) Serve Data Requests as part of the Formal Information Exchange, and 2) File Formal Challenges	September 22
Last Day for Company to Respond 1) Data Requests Served as Part of the Formal Information Exchange, and 2) Formal Challenges	October 6
Staff Report (if hearing not required)	October 31
Commission Decision (if necessary)	Before December 1
Rate Effective Date	First billing cycle of December
If any date should fall on a weekend or holiday the deadline shall move to the next business day.	

7. Update of the Formula Rate for FERC Form No. 1 and USoA References

APS may make a filing with the Commission that updates the FERC Form No. 1 and USoA references in its Formula Rate to reflect any FERC-mandated changes in the format for the FERC Form No. 1 or USoA that do not affect the rates derived from the Annual Update, which proceeding may not be used to raise issues unrelated to the proposed changes.

8. Updates related to Rate Cases

After a general rate case implementation, APS will effectuate a transfer of the FRAM Revenue recognized during the test year to base rates by (1) removing FRAM Revenues through an income statement pro forma adjustment, and (2) reduce the targeted FRAM revenue from Attachment 3 that correspond to the amount of the pro forma adjustment which will reduce the FRA applied to customer bills. For an Annual Update to the FRAM where a rate case was implemented during the FRAM test year, annualized adjustments will be made to reflect the outcomes of that rate case.

9. Interim Reporting and Review

APS shall file with the Commission a quarterly report of its asset additions. The reports shall be based on the three months ended March 31, June 30, September 30, and December 31 and shall be filed no later than the end of each subsequent quarter. At a minimum, the report shall include capital project numbers, descriptions, and asset addition amounts. Information requests from Staff and Interested Parties in accordance with Section 5 is permitted. The Company shall respond to any such requests in accordance with Section 5.

10. Term

APS will file a general rate case after five Annual Updates, or earlier if ordered by the Commission. The FRAM Annual Updates will continue through the resolution of the of the full rate case. At any point in the term of the FRAM, APS may voluntarily file a general rate case.

11. Supporting Schedules

The following Attachments and Standard Filing Requirements (SFRs) will be included with each Annual Update:

- Attachment 1 – FRAM Annual Adjustment Summary Schedule
- Attachment 2 – FRAM Interim Reports
- Attachment 3 – FRA Calculation
- SFR B-1 – Summary of Original Cost Rate Base Elements
- SFR B-2 – Original Cost Rate Base Pro Forma Adjustments
- SFR B-5 – Computation of Working Capital
- SFR C-1 – Income Statement
- SFR C-2 – Income Statement Pro Forma Adjustments
- SFR C-3 – Computation of Gross Revenue Conversion Factor
- SFR D-1 – Summary of Cost of Capital
- SFR E-1 – Comparative Balance Sheets
- SFR E-2 – Comparative Income Statements

Renewable Energy Standard Adjustment Schedule
Plan of Administration

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1. General Description

This document describes the plan for administering Arizona Public Service Company's (APS or the Company) Adjustment Schedule REAC-1, Renewable Energy Adjustment Charge (Schedule REAC-1). Schedule REAC-1 is the tariff required by the Arizona Corporation Commission's (Commission) Renewable Energy Standard and Tariff rules (the Rules) approved in Decision No. 69127 (November 14, 2006) and codified in A.A.C. R14-2-1801 *et. seq*., which provides for recovery of the costs incurred by the Company to meet its annual renewable energy requirement as set forth in the Rules.[1]

2. Allowable Costs

Schedule REAC-1 shall recover the cost of renewable programs included in the Company's annual Renewable Energy Standard Implementation Plan (RES Plan), and approved by the Commission, that are not otherwise recovered in base rates or other recovery mechanism. Allowable Costs include, but are not limited to, program development, program implementation, purchased power costs not recovered through the Power Supply Adjustor, customer incentives, customer education and communication, technical assistance and training, marketing and advertising, administrative and general expense, funds approved by the Commission for Coal Community Transition or similar programs, monitoring and evaluation, capital carrying costs for renewable energy-related capital investments made by APS[2] and other relevant costs.

Capital carrying costs include (1) a return at the Company's Weighted Average Cost of Capital found by the Commission in the Company's most recent general rate case; (2) depreciation expense; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits where appropriate and (6) associated operations and maintenance expenses.

[1] The Company's initial Schedule RES was approved by the Commission in Decision No. 70313 (April 28, 2008) and has been revised on an annual basis as described in this Plan of Administration.

[2] Capital carrying costs for any APS renewable energy-related capital investments made in conjunction with projects outside the scope of Decision Nos. 71448, 76295, and 78317 shall not be recovered through Schedule REAC-1 without separate Commission approval.

3. Balancing Account

Actual Allowable Costs shall be recorded in a separately maintained Balancing Account. Revenues received by APS through Schedule REAC-1, Rate Rider LFCR DG,[3] as well as other relevant revenue (including, but not limited to, forfeited PBI Reservation Deposits and Service Schedule 6 payments), shall be credited to the Balancing Account.

4. Adjustor Components

Schedule REAC-1 shall consist of a monthly kilowatt-hour (kWh) charge applied equally to all Standard Offer and Direct Access service. The kilowatt-hour charge is subject to a monthly surcharge limit calculated for specific customer billing classes as determined by the Company and approved by the Commission.

If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in Schedule REAC-1 in the subsequent calendar year.

5. Determination of the kWh Rate and Surcharge Limits for Schedule REAC-1

In accordance with Commission Decision No. 73183, customers who receive an incentive under the Renewable Energy Standard and install their system after July 1, 2012 will pay the applicable monthly surcharge limit. This provision shall be effective in billing cycle 1 after APS reprograms its billing system to accomplish this, or with the March 2013 billing, whichever is first.

Schedule REAC-1 shall be revised annually to recover projected Allowable Costs for the upcoming calendar year, and shall be based on programs and budgets contained in the Company's RES Plan and approved by the Commission. The Schedule REAC-1 kWh rate and surcharge limits shall be designed using projected billing determinants for the same period. The billing determinants shall include total retail kWh subject to Schedule REAC-1 and the number of customers and associated kWh that are billed under each surcharge limit.

6. Review and Approval Process

Schedule REAC-1 shall be filed for the upcoming calendar year as part of the Company's RES Plan, which is filed on July 1st each year as set forth in the Rules. Supporting information for the calculation of the kWh rate and surcharge limits as shown in Exhibit 1 to this Plan of Administration shall be provided. Schedule REAC-1 shall be updated to reflect the final approved budget for the upcoming year and an updated projected over and under collection in the Balancing Account through the end of the current year.

Once approved by the Commission, the Schedule REAC-1 rate and surcharge limits will be effective each year beginning with billing cycle 1 of the January revenue month or as otherwise

[3] LFCR DG revenues will be recorded in the Balancing Account following the first Formula Rate Adjustor Mechanism reset and the elimination of the Lost Fixed Cost Recovery mechanism.

ordered by the Commission and will not be prorated.

Renewable Energy Standard Adjustment Schedule
Plan of Administration

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1. General Description

This document describes the plan for administering Arizona Public Service Company's (APS or the Company) Adjustment Schedule REAC-1, Renewable Energy Adjustment Charge (Schedule REAC-1). Schedule REAC-1 is the tariff required by the Arizona Corporation Commission's (Commission) Renewable Energy Standard and Tariff rules (the Rules) approved in Decision No. 69127 (November 14, 2006) and codified in A.A.C. R14-2-1801 *et. seq*., which provides for recovery of the costs incurred by the Company to meet its annual renewable energy requirement as set forth in the Rules.[1]

2. Allowable Costs

Schedule REAC-1 shall recover the cost of renewable programs included in the Company's annual Renewable Energy Standard Implementation Plan (RES Plan), and approved by the Commission, that are not otherwise recovered in base rates or other recovery mechanism. Allowable Costs include, but are not limited to, program development, program implementation, purchased power costs not recovered through the Power Supply Adjustor, customer incentives, customer education and communication, technical assistance and training, marketing and advertising, administrative and general expense, funds approved by the Commission for Coal Community Transition or similar programs, monitoring and evaluation, capital carrying costs for renewable energy-related capital investments made by APS[2] and other relevant costs.

Capital carrying costs include (1) a return at the Company's Weighted Average Cost of Capital found by the Commission in the Company's most recent general rate case; (2) depreciation expense; (3) income taxes; (4) property taxes; (5) deferred taxes and tax credits where appropriate and (6) associated operations and maintenance expenses.

[1] The Company's initial Schedule RES was approved by the Commission in Decision No. 70313 (April 28, 2008) and has been revised on an annual basis as described in this Plan of Administration.

[2] Capital carrying costs for any APS renewable energy-related capital investments made in conjunction with projects outside the scope of Decision Nos. 71448, 76295, and 78317 shall not be recovered through Schedule REAC-1 without separate Commission approval.

3. Balancing Account

Actual Allowable Costs shall be recorded in a separately maintained Balancing Account. Revenues received by APS through Schedule REAC-1, Rate Rider LFCR DG,[3] as well as other relevant revenue (including, but not limited to, forfeited PBI Reservation Deposits and Service Schedule 6 payments), shall be credited to the Balancing Account.

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Schedule REAC-1 shall consist of a monthly kilowatt-hour (kWh) charge applied equally to all Standard Offer and Direct Access service. The kilowatt-hour charge is subject to a monthly surcharge limit calculated for specific customer billing classes as determined by the Company and approved by the Commission.

If the Balancing Account has accrued an over or under collected balance in a given period, any such over or under collection shall be included in Schedule REAC-1 in the subsequent calendar year.

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In accordance with Commission Decision No. 73183, customers who receive an incentive under the Renewable Energy Standard and install their system after July 1, 2012 will pay the applicable monthly surcharge limit. This provision shall be effective in billing cycle 1 after APS reprograms its billing system to accomplish this, or with the March 2013 billing, whichever is first.

Schedule REAC-1 shall be revised annually to recover projected Allowable Costs for the upcoming calendar year, and shall be based on programs and budgets contained in the Company's RES Plan and approved by the Commission. The Schedule REAC-1 kWh rate and surcharge limits shall be designed using projected billing determinants for the same period. The billing determinants shall include total retail kWh subject to Schedule REAC-1 and the number of customers and associated kWh that are billed under each surcharge limit.

6. Review and Approval Process

Schedule REAC-1 shall be filed for the upcoming calendar year as part of the Company's RES Plan, which is filed on July 1st each year as set forth in the Rules. Supporting information for the calculation of the kWh rate and surcharge limits as shown in Exhibit 1 to this Plan of Administration shall be provided. Schedule REAC-1 shall be updated to reflect the final approved budget for the upcoming year and an updated projected over and under collection in the Balancing Account through the end of the current year.

Once approved by the Commission, the Schedule REAC-1 rate and surcharge limits will be effective each year beginning with billing cycle 1 of the January revenue month or as otherwise

[3] LFCR DG revenues will be recorded in the Balancing Account following the first Formula Rate Adjustor Mechanism reset and the elimination of the Lost Fixed Cost Recovery mechanism.

ordered by the Commission and will not be prorated.

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

General Description

This schedule establishes the terms and conditions under which Company will extend, relocate, and upgrade its facilities in order to provide service. Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or the relocation or upgrade of existing facilities. Costs for construction depend on the applicant's location, scope of project, load size, and load characteristics. Costs include, but are not limited to, project management, coordination, engineering, design, surveys, permits, construction inspection, and support services.

All facility installations and upgrades will be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following provisions govern the installation of overhead and underground electric distribution facilities to applicants whose requirements are deemed by Company to be usual and reasonable in nature.

1. Definitions

1.1. **APS Approved Electrical Distribution Contractor** means an electrical contractor who is licensed in the State of Arizona and properly qualified to install electric distribution facilities in accordance with Company standards and good utility construction practices as determined by Company.

1.2. **Backbone Infrastructure** means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

1.3. **Conduit Only Design** means the conduit layout design for the installation of underground Extension Facilities that will be required when the Extension Facilities are to be installed at a later date.

1.4. **Conversion** means converting overhead distribution facilities to underground facilities.

1.5. **Corporate Business and Industrial Park Development** means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial or industrial use.

1.6. **Doubtful Permanency means** a customer who, in the opinion of the Company, is neither Permanent nor Temporary. Service which, in the opinion of the Company, is for operations of a speculative character is considered Doubtfully Permanent.

1.7. **Economic Feasibility** means a determination by Company that the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding

taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the applicant.

1.8. **Execution Date** means the date Company signs the agreement after the applicant has signed the agreement and money has been collected by company.

1.9. **Extension Facilities** means the electrical facilities, including conductors, cables, transformers, and related equipment, installed solely to serve an individual applicant or groups of applicants. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to connect the subdivision to Company's existing system as well as Company's electrical facilities constructed within the subdivision which would include primary and service lines, and transformers.

1.10. **High Rise Development** means a building built with four or more floors (usually using elevators for accessing floors) that may consist of residential or non-residential use, or a combination of both residential and non-residential uses.

1.11. **Irrigation** means water pumping service.

1.12. **Limited-Income Multi-Unit Residential Housing** means multi-unit housing that primarily leases to lower income or very low-income residents as defined by the U.S. Department of Housing and Urban Development HUD Public Housing Program.

1.13. **Line Extension Agreement** means the contractual agreement between Company and applicant that defines applicant payment requirements, terms of refund, scope of project, estimated costs, and construction responsibilities for Company and the applicant. Line Extension Agreements may be assigned to applicant's successors in interest with Company approval, which approval will not be unreasonably withheld.

1.14. **Master Planned Community Development** means a development that consists of a number of separately subdivided parcels for different Residential Subdivisions. The development may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.

1.15. **Master Meter** means a meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

1.16. **Metro Area** means a city with a population of 750,000 or more and its contiguous and surrounding communities.

1.17. **Mixed-Use Development** means a development that consists of both residential and non-residential uses, such as a building with three stories or less, where the first level is for commercial purposes and the upper floors are for residential units, or a development that includes an apartment complex and a commercial center, or a development that includes a subdivision and a water treatment plant.

1.18. **Permanent** means a customer who is a tenant or owner of a service location who applies for and receives electric service, which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature. Permanency at the service location may be established by such things

as city/county/state permits, a permanent water system, an approved sewer/septic system, or other permanent structures.

1.19. **Project-Specific Cost Estimate** means cost estimates that are developed recognizing the unique characteristics of large or special projects to which the Schedule of Charges is not applicable. A Project-Specific Cost Estimate provided to an applicant is valid for a period of up to six months from the date the estimate is provided to the applicant.

1.20. **Relocation** means moving a distribution line or facilities from its current location to a new location.

1.21. **Residential "Lot Sale" Development** means a tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home and the costs to provide service, which may include backbone, transformer and service.

1.22. **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses with less than four floors.

1.23. **Residential Single Family** means a house, or a manufactured or mobile home Permanently affixed to a lot or site.

1.24. **Residential Subdivision** means a tract of land, which has been divided into four or more contiguous lots with an average size of one acre or less, in which the developer is responsible for the costs to provide service, including backbone, transformers and services for the residential homes or permanent manufactured or mobile home sites.

1.25. **Residual Value** means the remaining un-depreciated original cost of the existing facilities to be removed.

1.26. **Arizona Rural Municipality** means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

1.27. **Rural Municipal Business Development** means a tract of land which has been divided into contiguous lots, is owned and developed by an Arizona Rural Municipality, and where the Arizona Rural Municipality will be the lease-holder for future permanent applicants.

1.28. **Schedule of Charges** means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities.

1.29. **Service Entrance Upgrade** means the replacement of the customer's electric panel to one with larger load capacity. This includes panels that are upgraded to a larger amperage rating, greater voltage or additional phases (1 phase to 3 phase).

1.30. **Temporary** means premises or enterprises which are temporary in character, or where it is known in advance that the Extension Facilities will be of limited duration.

1.31. **Voltage** for purposes of APS rates, secondary voltage is considered 600v and below. Primary is considered 601v up to 69k~~v~~V. Transmission is 69k~~v~~V and above. For clearances or engineering purposes refer to APS's Electric Service Requirements Manual.

2. General Provisions for Service

2.1. **Applicant Classification** - For the purposes of this Service Schedule 3, applications for Extension Facilities will be classified as "Residential" or "General Service" as listed below, and further described in the referenced sections.

(A) Residential classifications are: "Residential Single Family Home" (Section 3), "Residential Subdivision Developments" (Section 4), "Residential "Lot Sale" Developments (Section 5), "Master Planned Community Developments" (Section 6) or "Residential Multi-Family Developments" (Section 7).

(B) General Service classifications are: "Basic General Service" (Section 9), "High Rise Developments" (Section 10), Mixed-Use Developments (Section 11), "Corporate Business & Industrial Park Developments" (Section 12), Temporary Applicants (Section 13), and Doubtful Permanency Customers (Section 14).

2.2. **Schedule of Charges** - An applicant requesting an extension will be provided a sketch showing the Extension Facilities and a quote based on the Schedule of Charges or other applicable details. When the Schedule of Charges is not applicable, charges for Extension Facilities will be determined by the Company based on Project-Specific Cost Estimates. The Schedule of Charges is not applicable for the following:

(A) Extension Facilities requiring modifications, removal, relocations or conversions of existing facilities in conjunction with a new extension or existing customer requested upgrade. The removal, replacement, conversion, and new Extension Facilities charges will be determined by a combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project and may include residual value costs as computed in accordance with the method described in A.R.S 40-347.

(B) Extension Facilities required for modifications, relocations or conversions of existing facilities not in conjunction with a new extension or existing customer upgrade.

(C) Subdivisions 100 lots or greater or that require feeder, backbone and/or major infrastructure to serve development.

(D) Extension Facilities for General Service applicants that require feeder, backbone and/or major infrastructure or specialized equipment to serve project.

(E) Extension Facilities required for High Rise Developments, Mixed-Use Developments, Master Planned Developments, Residential Lot Sale, Corporate Business and Industrial Park Developments, or Temporary service.

(F) Extension Facilities involving spot networks, vault installations, primary metering, or specialized or additional equipment for enhanced reliability.

(G) Special studies, leases or permits required by the city, county, state or federal governmental agency for installing electric facilities on private, government or public lands.

2.3. **General Underground Construction Policy** - With respect to all underground installations under a Line Extension Agreement, Company will install underground facilities only if all of the following conditions are met:

(A) The Extension Facilities meet all requirements as specified in "Residential" or "General Service" Sections 2.1 (A) & (B) of this Service Schedule 3.

(B) The applicant signs a trench agreement and provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

(C) The applicant provides installation of equipment pads, pull-boxes, manholes, conduits, and appurtenances as required and in accordance with Company specifications.

(D) In lieu of applicant providing these services and equipment, the applicant may pay Company to provide these services and equipment as a non-refundable contribution in aid of construction. The payment will equal the cost of such work plus any administrative or inspection fees incurred by Company. Applicants electing this option will be required to sign an agreement indemnifying and holding Company harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than Company's contractors, which Claims arise out of the trenching and conduit placement, provided the Claims are not attributable to the Company's gross negligence or intentional misconduct.

2.4. **Refunds** – The following general refund conditions will apply:

(A) No refund will be made to any applicant for an amount more than the unrefunded balance of the applicant's refundable advance.

(B) The Company reserves the right to withhold refunds to any applicant who is delinquent on any account, agreement, or invoice, including the payment of electric service, and may apply these refund amounts to past due bills.

(C) The refund eligibility period for Basic General Service and High-Rise Development will be five years from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(D) The refund eligibility period for Residential Subdivisions and Multi-Family Developments will be five years and will start three months from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(E) Refunds will be mailed to the applicant of record noted on the executed agreement no later than 60-days from the annual review date.

2.5. **Interest** - All refundable advances made by the applicant to the Company will be non-interest bearing.

2.6. **Ownership** - Except for applicant owned facilities, all Extension Facilities installed in accordance with this Service Schedule 3 will be owned, operated, and maintained by Company.

RESIDENTIAL

3. Residential Single Family Homes

3.1. Extension Facilities will be installed to new Permanent residential applicants or groups of new Permanent residential applicants on an allowance under the following conditions:
- (A) A Line Extension Agreement signed by the applicant and construction costs in excess of the allowances, as described in 3.1(C) and 3.2 will be paid by the applicant before the Company begins installing facilities. Payment is due at the time the Line Extension Agreement is signed by the applicant.
- (B) The site plan has been approved and recorded in the county having jurisdiction.
- (C) The total cost of the Extension Facilities (primary, secondary, service), as determined by Company, is less than $10,000 per applicant.

3.2. All additional construction costs over $10,000 per applicant will be paid by applicant as a non-refundable contribution in aid of construction.

3.3. Applicants who combine to form a group may also combine their allowance as specified in Sections 3.1(C) and 3.2.

3.4. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project which will exclude the cost of one single-phase transformer.

3.5. The allowance cap of $10,000 will be reviewed from time to time with the Arizona Corporation Commission.

4. Residential Subdivision Developments

4.1. Extension Facilities will be installed to Residential Subdivision developments of four or more homes in advance of application for service by Permanent customers under the following conditions:
- (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of construction by the Company. Payment is due at the time the Line Extension Agreement is signed by the applicant.
- (B) The subdivision development plat has been approved and recorded in the county having jurisdiction. Applicant is responsible for providing Company an approved subdivision plat prior to project design. If the final approved plat is different from what was originally submitted to the Company, it may cause delays and additional cost for redesign.

4.2. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

4.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per lot" allowance provisions of Section 4.6 and in accordance with Section 2.4.

4.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition or organizational structure of developer.

4.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights.

4.6. The refundable advance will be eligible for refund based on a "per lot" allowance of $3,500 for each Permanently connected residential customer over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date the Company executes the Line Extension Agreement with the applicant. A review of the project will be conducted annually to determine subdivision buildout, and if the qualifications have been met for any refunds.

4.7. Examples of the application of Section 4 can be found in Attachment 1 – Residential Subdivision Illustrative Example.

5. Residential "Lot Sale" Developments

5.1. Extension Facilities will be installed to residential "Lot Sale" developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The development plat has been approved and recorded in the county having jurisdiction.

5.2. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost Estimate.

5.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

5.4. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

5.5. Extension Facilities will be installed to individual applicants in accordance with provisions listed in Section 3.

6. Master Planned Community Developments

6.1. Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by Permanent applicants under the following conditions:
   (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
   (B) The site development plan has been approved and recorded in the county having jurisdiction.

6.2. The cost of extending service to applicant will be determined by a Project-Specific Cost Estimate.

6.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

6.4. Extension Facilities will be installed to each subdivided tract within the planned development in accordance with the applicable sections of this Service Schedule 3.

7. Residential Multi-Family Developments

7.1. Extension Facilities will be installed to Residential Multi-Family Developments in advance of application for service by Permanent customers under the following conditions:
   (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
   (B) The site development plan has been approved and recorded in the county having jurisdiction.

7.2. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost estimate.

7.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per unit" refundable allowance provisions of Section 7.6 and in accordance with Section 2.4.

7.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition, or organizational structure of applicant.

7.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights etc.

7.6. The refundable advance will be eligible for refund based on a "per unit" allowance of $1,000 for each new meter, installed for a permanent residential structure, over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement. A review of the project will be conducted annually to determine buildout and if the qualifications have been met for any refunds.

GENERAL SERVICE

8. General Service Provisions

8.1. Extension Facilities that do not meet the requirements under Residential Sections 3, 4, 5, 6, or 7 will be considered General Service and will be installed to all applicants who meet the qualifications under Sections 9, 10, 11, 12, 13, or 14 of this Service Schedule 3.

9. Basic General Service

9.1. Extension Facilities will be installed to Basic General Service in advance of application for service by Permanent applicants under the following conditions:
   (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
   (B) The site development plan for the project for which the Line Extension has been requested has been approved and recorded in the county having jurisdiction.

9.2. The project costs for Basic General Service installations will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or a combination of Schedule of Charges and Project-Specific Cost Estimate depending on the scope of the project.

9.3. The cost for Extension Facilities that require feeder, backbone, major infrastructure, or specialized equipment to serve the project, will be determined in accordance with a Project-Specific Cost Estimate.

9.4. Economic Feasibility Analysis for Basic General Service Applicants - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:
   (A) Project Cost $25,000 or less - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant

contributions such as street lights and other non-standard construction charges) is $25,000 or less will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) multiplied by six is equal to or greater than the cost of the applicant's Extension Facilities.

(B) Project Cost greater than $25,000 - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(C) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(D) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

(E) Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(F) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10. High Rise Developments

10.1. Extension Facilities will be installed to High Rise Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

(D) Extension Facilities will be installed to designated points of delivery in accordance with APS' Electric Service Requirements Manual (ESRM). It is the applicant's responsibility to provide and maintain the electrical facilities within the building.

10.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

10.3. Economic Feasibility Analysis for High Rise Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10.4. Before Company orders specialized materials or equipment required to provide service, applicant will be required to make an advance payment to the Company for the

estimated cost of the material or equipment in accordance with Section 27.2.

11. Mixed-Use Developments

11.1. Extension Facilities will be installed to Mixed-Use Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

11.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

11.3. Economic Feasibility Analysis for Mixed Use Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the

unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

11.4. Before Company orders specialized materials or equipment required to provide service applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

12. Corporate Business & Industrial Park Developments

12.1. Extension Facilities will be made to Corporate Business and Industrial Park Developments in advance of application for service by Permanent customer under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

12.2. The cost of installing Extension Facilities will be determined in accordance with a Project-Specific Cost Estimate.

12.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

12.4. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

12.5. Extension Facilities will be installed to individual lots (at the request of an applicant) within the Corporate Business and Industrial Park Development in accordance with the applicable sections of this Service Schedule 3.

13. Temporary Applicants

13.1. Where Temporary Extension Facilities are required to provide service to the applicant, the applicant will make a non-refundable payment in advance of installation or construction equal to the cost of installing and removing of the facilities required in providing Temporary service, less the salvage value of such facilities. Charges will be determined by Company based on a Project-Specific Cost Estimate.

13.2. A Line Extension Agreement signed by the applicant and advance payment of all project

costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

13.3. When use of the Temporary service is discontinued or service is terminated, Company may dismantle and remove its facilities and the materials and equipment provided by Company will remain Company property.

14. Doubtful Permanency Customers

14.1. When, in the opinion of Company, permanency of the applicant's residence or operation is doubtful, the applicant will be required to pay the total cost of the Extension Facilities. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost Estimate. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

14.2. A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

OTHER CONDITIONS

15. Municipalities and Other Governmental Agencies

15.1. Extension Facility installations, relocations, or conversions of existing facilities required to serve loads of municipalities or other governmental agencies may be constructed before the receipt of a signed Line Extension Agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the Extension Facilities costs in accordance with the applicable sections of this Service Schedule 3.

15.2. The effective date for projects enacted under this provision for purposes of Section 2.4 will be the date the municipality or agency provided written approval to the Company to proceed with construction.

16. Change in Applicant's Service Requirements

16.1. Company will rebuild, modify, or upgrade its existing facilities to meet the applicant's added load, service entrance upgrade, or change in service requirements on the basis specified in Sections 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, or 14. Charges for such changes will be in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a Project-Specific Cost Estimate determined by the Company based on project-specific requirements.

17. Relocations, Conversions and Upgrades of Company Facilities

17.1. **Relocations** - Company will relocate its facilities at the applicant's request. The cost of relocations not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) When the relocation of Company facilities involves "prior rights" conditions, the applicant will be required to make payment equal to the estimated cost of relocation as a non-refundable contribution in aid of construction. In addition, applicant will be required to provide similar "rights" for the relocated facilities.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by applicant.

17.2. **Conversions** - Company will convert from overhead to underground its facilities at applicant request. The cost of conversions not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate and may include residual value costs as computed in accordance with the method described in A.R.S. Section 40-347.

(A) The applicant will be required to make a payment equal to the estimated cost of conversion as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

17.3. **Upgrades** - Company will upgrade its facilities at applicant request. The cost of Company facility upgrades not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) The applicant will be required to make a payment equal to the estimated cost of the upgrade as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

18. Additional Primary Feed or Specialized Equipment

18.1. When specifically requested by an applicant to provide an alternate primary feed or specialized equipment (excluding transformation), Company will perform a special study to determine the feasibility of the request. The applicant will be required to pay for the cost of the additional feed requested as a non-refundable contribution in aid of construction. Installation cost will be based on a Project-Specific Cost Estimate. Payment for the installation of Extension Facilities is due at the time the Line Extension Agreement is signed by the applicant.

19. Unusual Circumstances

19.1. In unusual circumstances as determined by Company, when the application and provisions of this Service Schedule 3 appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when applicant's estimated demand load will exceed 3,000 kW, Company may make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

20. Abnormal Loads

20.1. Company, at its option, may install Extension Facilities to serve certain abnormal loads (such as transformer type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the applicant will be included in the payment described in previous sections of this Service Schedule 3.

21. Master Metering

21.1. **Mobile Home Parks** - Company will refuse service to all new construction or expansion of existing Permanent residential mobile home parks unless the construction or expansion is individually metered by Company.

21.2. **Residential Apartment Complexes, Condominiums** - Company will refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Arizona Administrative Code and the requirements discussed in 21.3 below. This section is not applicable under the following conditions:

(A) For Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care or;

(B) For Limited-Income Multi-Unit Residential Housing that uses solar power in a "behind-the-meter" application

21.3. **Multi-Unit High Rise Residential Developments** - Company will allow master metering for high rise residential units under the following conditions:

(A) The building will be served by a centralized heating, ventilation or air conditioning system.

(B) Each residential unit will be individually sub-metered and responsible for energy consumption of that unit.

(C) Sub-metering will be provided and maintained by the builder or homeowners association.

(D) Responsibility and methodology for determining each unit's energy billing will be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company before Company installing Extension Facilities.

21.4. **Conversion from master meter to individually metered system** - Company will convert its facilities from a master metered system to a permanent individually metered system at the applicant's request provided the applicant makes a non-refundable contribution in aid of construction equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended in accordance with the applicable sections of this Service Schedule 3. Applicant is responsible for all costs related to the installation of new service entrance equipment.

22. Voltage

22.1. All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the Extension Facilities are located. At the request of applicant, Company may, at its option, deliver service for special applications of non-standard or higher voltages with prior approval from Company's Engineering Department. Applicant will be required to pay the costs of any required studies as a non-refundable payment.

22.2. Extension Facilities installed at higher voltages will be limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or separated by public property or public right–of- way.

23. Point of Delivery

23.1. For overhead service, the point of delivery will be where Company's service conductors terminate at the applicant's weatherhead or bus riser.

23.2. For underground service, the point of delivery will be where Company's service conductors terminate in the applicant's or development's service equipment. The applicant will furnish, install and maintain any risers, raceways and termination cabinets necessary for the installation of Company's underground service conductors.

23.3. For special applications where service is provided at voltages higher than the standard voltages specified in the APS Electric Service Requirements Manual, Company and applicant will mutually agree upon the designated point of delivery.

24. Easements

24.1. Before Company begins construction of Extension Facilities, all suitable easements and rights-of-way required for any portion of the extension will be obtained by applicant and provided to Company in Company's name without cost to or condemnation by Company. All easements and rights-of-way obtained on behalf of Company will be on Company's standard easement form which contains the terms and conditions that are acceptable to Company.

25. Grade Modifications

25.1. If after construction of Extension Facilities, the final grade of the property established by the applicant is changed in such a way as to require relocation of Company facilities, or the applicant's actions or those of his contractor results in damage to such facilities, the cost of replacement, relocation, or any resulting repairs will be borne by applicant as a non-refundable contribution in aid of construction.

26. Measurement and Location

26.1. Measurement must be along the proposed route of construction.
26.2. Construction will be on public streets, roadways, highways, or easements acceptable to Company.
26.3. The Extension Facilities must be a branch from, the continuation of, or an addition to, Company's existing distribution facilities.

27. Agreements

27.1. **Study and Design Agreements** - Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company in an amount equal to the estimated cost of preparation. When the applicant authorizes Company to proceed with construction of the Extension Facilities, the payment will be credited to the cost of the Extension Facilities otherwise the payment will be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.
27.2. **Material Order Agreements** - Any applicant requesting Company to enter into a Line Extension Agreement or relocation agreement which requires either large quantities of material or material and equipment which the Company does not keep in stock will be required to make a payment to Company before the material being ordered in an amount equal to the material/equipment's estimated cost. When the applicant authorizes Company to proceed with construction of the extension, the payment will be

credited to the cost of the extension; otherwise, the payment will be non-refundable.

27.3. **Line Extension Agreements** - All facility installations or equipment upgrades requiring payment by an applicant will be in writing and signed by both the applicant and Company.

28. Applicant Construction of Company Distribution Facilities

28.1. Applicant may provide construction related labor only services associated with the installation of new distribution line facilities (21 kV and below) to serve the applicant's new or added load provided the applicant receives written approval from Company before performing any such services and uses electrical contractors who are qualified and licensed in the State of Arizona to construct such facilities and designated as an APS Approved Electrical Distribution Contractor.

28.2. This option is not available for the following:

(A) Replacement, modifications, upgrades, relocation, or conversions of existing systems.

(B) Where all or a portion of the distribution line facilities are to be constructed on or installed on existing distribution line or transmission lines.

28.3. All construction services provided by the applicant will be subject to inspection by a duly authorized Company representative and will comply with Company designs, construction standards, and other requirements which may be in effect at the time of construction. Any work found to be substandard in the sole opinion of the Company must be corrected by applicant before energization by Company.

28.4. Applicant will reimburse Company for all inspection and project coordination costs as a non-refundable contribution in aid of construction. Estimated costs for inspection and project coordination will be identified in the construction agreement executed by Company and applicant.

28.5. Costs for Extension Facilities for applicants who provide construction of Company distribution facilities will be based on a Project-Specific Cost Estimate.

28.6. A signed agreement and payment of all project costs minus labor are required before the start of applicant construction. Payment is due at the time the agreement is signed by the applicant.

28.7. For applicants that are not served by the terms in General Service Sections of this document, Company will provide a Project-Specific Cost Estimate. Applicants may submit an invoice detailing costs of Extension Facilities and apply any allowance provided in Residential Sections 3, 4, or 7 to these costs. At no point will these costs exceed the Company's Project-Specific Cost Estimate.

28.8. Applicants served by the terms in General Service Sections 9, 10, 11, 12, 13, or 14 of this document will be subject to the rules set forth in the respective section and Refund Section 2.4.

29. Settlement of Disputes

29.1. Any dispute between the applicant or prospective applicant and the Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may be referred to the Arizona Corporation Commission or a designated representative or employee for determination by either party.

30. Policy Exceptions

30.1. This Schedule 3 is applicable to all applicants unless specific exceptions are approved by the Arizona Corporation Commission.

(A) The following exceptions have been approved for Rural Municipality applicants:

i. Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of application for service by permanent applicants.

ii. The cost of installing Extension Facilities to Rural Municipal Business Developments will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project.

iii. The refund eligibility period for Rural Municipal Business Developments will be 7 years from the date the Company executes the Line Extension Agreement with the Rural Municipality applicant.

iv. Rural Municipal Business Development applicants will be required to advance payment of one-half of the project costs at the time the Line Extension Agreement is signed and before the start of Company construction. The balance of the project cost will be required 7 years from the Execution Date of the agreement if the project has not become economically feasible by the end of the 7th year refundable period. Any unrefunded advance balance paid at the start of the project, plus the balance of project costs due at the end of refund period, will become a non-refundable contribution in aid of construction 7 years from the Execution Date of the agreement.

v. Company may require a Surety Bond, Irrevocable Letter of Credit or Assignment of Monies in amount equal to any Advance not collected at the start of construction.

vi. The Economic Feasibility analysis for the Rural Municipal Business Development's Extension Facilities will be reviewed at the end of the third, fifth and seventh year of the Line Extension Agreement based on the average monthly demand within the Rural Municipal Business Development for the preceding year and to the degree that the average monthly demand supports

the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

vii. Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

(B) The following exceptions for sections 3, 7, 9, 10, and 11 have been approved for Hopi and Navajo applicants for the extension of electric service to residential and commercial buildings within the Navajo Nation and the Hopi Reservation that are in the APS service territory.

i. APS distribution facilities will be extended up to 2,000 feet at no cost to such applicants.

ii. Applicants requiring distribution facilities extending more than 2,000 feet will pay the amount as calculated through the schedule of charges or project specific costs for any distribution facilities after the initial 2,000 feet from existing APS distribution consistent with the application sections of this schedule.

SCHEDULE OF CHARGES

Description	Rate	Unit
Single Family Underground	$ ~~8.40~~11.47	Per foot
Single Family Overhead	$ ~~22.40~~23.89	Per foot
Residential Subdivision*	$ ~~12.26~~16.86	Per foot
General Service and Commercial, Single Phase, Underground	$ ~~16.06~~21.05	Per foot
General Service and Commercial, Single Phase, Overhead	$ ~~28.12~~33.46	Per foot
General Service and Commercial, Three Phase, Underground	$ ~~42.81~~54.53	Per foot
General Service and Commercial, Three Phase, Overhead	$ ~~59.04~~65.29	Per foot
Single Phase Pole Interset (pole set in existing line)	$ 7,133.39	Each
Three Phase Pole Interset (pole set in existing line)	$ 9,378.39	Each
*Residential Subdivision projects with 100 or more lots will be determined via project specific costs.		

Attachment 1
Residential Subdivision Illustrative Example

Scenario 1	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 2	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 3	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Scenario 4	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

General Description

This schedule establishes the terms and conditions under which Company will extend, relocate, and upgrade its facilities in order to provide service. Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or the relocation or upgrade of existing facilities. Costs for construction depend on the applicant's location, scope of project, load size, and load characteristics. Costs include, but are not limited to, project management, coordination, engineering, design, surveys, permits, construction inspection, and support services.

All facility installations and upgrades will be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following provisions govern the installation of overhead and underground electric distribution facilities to applicants whose requirements are deemed by Company to be usual and reasonable in nature.

1. Definitions

1.1. **APS Approved Electrical Distribution Contractor** means an electrical contractor who is licensed in the State of Arizona and properly qualified to install electric distribution facilities in accordance with Company standards and good utility construction practices as determined by Company.

1.2. **Backbone Infrastructure** means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.

1.3. **Conduit Only Design** means the conduit layout design for the installation of underground Extension Facilities that will be required when the Extension Facilities are to be installed at a later date.

1.4. **Conversion** means converting overhead distribution facilities to underground facilities.

1.5. **Corporate Business and Industrial Park Development** means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial or industrial use.

1.6. **Doubtful Permanency means** a customer who, in the opinion of the Company, is neither Permanent nor Temporary. Service which, in the opinion of the Company, is for operations of a speculative character is considered Doubtfully Permanent.

1.7. **Economic Feasibility** means a determination by Company that the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding

taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the applicant.

1.8. **Execution Date** means the date Company signs the agreement after the applicant has signed the agreement and money has been collected by company.

1.9. **Extension Facilities** means the electrical facilities, including conductors, cables, transformers, and related equipment, installed solely to serve an individual applicant or groups of applicants. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to connect the subdivision to Company's existing system as well as Company's electrical facilities constructed within the subdivision which would include primary and service lines, and transformers.

1.10. **High Rise Development** means a building built with four or more floors (usually using elevators for accessing floors) that may consist of residential or non-residential use, or a combination of both residential and non-residential uses.

1.11. **Irrigation** means water pumping service.

1.12. **Limited-Income Multi-Unit Residential Housing** means multi-unit housing that primarily leases to lower income or very low-income residents as defined by the U.S. Department of Housing and Urban Development HUD Public Housing Program.

1.13. **Line Extension Agreement** means the contractual agreement between Company and applicant that defines applicant payment requirements, terms of refund, scope of project, estimated costs, and construction responsibilities for Company and the applicant. Line Extension Agreements may be assigned to applicant's successors in interest with Company approval, which approval will not be unreasonably withheld.

1.14. **Master Planned Community Development** means a development that consists of a number of separately subdivided parcels for different Residential Subdivisions. The development may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.

1.15. **Master Meter** means a meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.

1.16. **Metro Area** means a city with a population of 750,000 or more and its contiguous and surrounding communities.

1.17. **Mixed-Use Development** means a development that consists of both residential and non-residential uses, such as a building with three stories or less, where the first level is for commercial purposes and the upper floors are for residential units, or a development that includes an apartment complex and a commercial center, or a development that includes a subdivision and a water treatment plant.

1.18. **Permanent** means a customer who is a tenant or owner of a service location who applies for and receives electric service, which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature. Permanency at the service location may be established by such things

as city/county/state permits, a permanent water system, an approved sewer/septic system, or other permanent structures.

1.19. **Project-Specific Cost Estimate** means cost estimates that are developed recognizing the unique characteristics of large or special projects to which the Schedule of Charges is not applicable. A Project-Specific Cost Estimate provided to an applicant is valid for a period of up to six months from the date the estimate is provided to the applicant.

1.20. **Relocation** means moving a distribution line or facilities from its current location to a new location.

1.21. **Residential "Lot Sale" Development** means a tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home and the costs to provide service, which may include backbone, transformer and service.

1.22. **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses with less than four floors.

1.23. **Residential Single Family** means a house, or a manufactured or mobile home Permanently affixed to a lot or site.

1.24. **Residential Subdivision** means a tract of land, which has been divided into four or more contiguous lots with an average size of one acre or less, in which the developer is responsible for the costs to provide service, including backbone, transformers and services for the residential homes or permanent manufactured or mobile home sites.

1.25. **Residual Value** means the remaining un-depreciated original cost of the existing facilities to be removed.

1.26. **Arizona Rural Municipality** means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.

1.27. **Rural Municipal Business Development** means a tract of land which has been divided into contiguous lots, is owned and developed by an Arizona Rural Municipality, and where the Arizona Rural Municipality will be the lease-holder for future permanent applicants.

1.28. **Schedule of Charges** means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities.

1.29. **Service Entrance Upgrade** means the replacement of the customer's electric panel to one with larger load capacity. This includes panels that are upgraded to a larger amperage rating, greater voltage or additional phases (1 phase to 3 phase).

1.30. **Temporary** means premises or enterprises which are temporary in character, or where it is known in advance that the Extension Facilities will be of limited duration.

1.31. **Voltage** for purposes of APS rates, secondary voltage is considered 600v and below. Primary is considered 601v up to 69kV. Transmission is 69kV and above. For clearances or engineering purposes refer to APS's Electric Service Requirements Manual.

2. General Provisions for Service

2.1. **Applicant Classification** - For the purposes of this Service Schedule 3, applications for Extension Facilities will be classified as "Residential" or "General Service" as listed below, and further described in the referenced sections.

(A) Residential classifications are: "Residential Single Family Home" (Section 3), "Residential Subdivision Developments" (Section 4), "Residential "Lot Sale" Developments (Section 5), "Master Planned Community Developments" (Section 6) or "Residential Multi-Family Developments" (Section 7).

(B) General Service classifications are: "Basic General Service" (Section 9), "High Rise Developments" (Section 10), Mixed-Use Developments (Section 11), "Corporate Business & Industrial Park Developments" (Section 12), Temporary Applicants (Section 13), and Doubtful Permanency Customers (Section 14).

2.2. **Schedule of Charges** - An applicant requesting an extension will be provided a sketch showing the Extension Facilities and a quote based on the Schedule of Charges or other applicable details. When the Schedule of Charges is not applicable, charges for Extension Facilities will be determined by the Company based on Project-Specific Cost Estimates. The Schedule of Charges is not applicable for the following:

(A) Extension Facilities requiring modifications, removal, relocations or conversions of existing facilities in conjunction with a new extension or existing customer requested upgrade. The removal, replacement, conversion, and new Extension Facilities charges will be determined by a combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project and may include residual value costs as computed in accordance with the method described in A.R.S 40-347.

(B) Extension Facilities required for modifications, relocations or conversions of existing facilities not in conjunction with a new extension or existing customer upgrade.

(C) Subdivisions 100 lots or greater or that require feeder, backbone and/or major infrastructure to serve development.

(D) Extension Facilities for General Service applicants that require feeder, backbone and/or major infrastructure or specialized equipment to serve project.

(E) Extension Facilities required for High Rise Developments, Mixed-Use Developments, Master Planned Developments, Residential Lot Sale, Corporate Business and Industrial Park Developments, or Temporary service.

(F) Extension Facilities involving spot networks, vault installations, primary metering, or specialized or additional equipment for enhanced reliability.

(G) Special studies, leases or permits required by the city, county, state or federal governmental agency for installing electric facilities on private, government or public lands.

2.3. **General Underground Construction Policy** - With respect to all underground installations under a Line Extension Agreement, Company will install underground facilities only if all of the following conditions are met:

(A) The Extension Facilities meet all requirements as specified in "Residential" or "General Service" Sections 2.1 (A) & (B) of this Service Schedule 3.

(B) The applicant signs a trench agreement and provides all earthwork including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.

(C) The applicant provides installation of equipment pads, pull-boxes, manholes, conduits, and appurtenances as required and in accordance with Company specifications.

(D) In lieu of applicant providing these services and equipment, the applicant may pay Company to provide these services and equipment as a non-refundable contribution in aid of construction. The payment will equal the cost of such work plus any administrative or inspection fees incurred by Company. Applicants electing this option will be required to sign an agreement indemnifying and holding Company harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than Company's contractors, which Claims arise out of the trenching and conduit placement, provided the Claims are not attributable to the Company's gross negligence or intentional misconduct.

2.4. **Refunds** – The following general refund conditions will apply:

(A) No refund will be made to any applicant for an amount more than the unrefunded balance of the applicant's refundable advance.

(B) The Company reserves the right to withhold refunds to any applicant who is delinquent on any account, agreement, or invoice, including the payment of electric service, and may apply these refund amounts to past due bills.

(C) The refund eligibility period for Basic General Service and High-Rise Development will be five years from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(D) The refund eligibility period for Residential Subdivisions and Multi-Family Developments will be five years and will start three months from the date the Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.

(E) Refunds will be mailed to the applicant of record noted on the executed agreement no later than 60-days from the annual review date.

2.5. **Interest** - All refundable advances made by the applicant to the Company will be non-interest bearing.

2.6. **Ownership** - Except for applicant owned facilities, all Extension Facilities installed in accordance with this Service Schedule 3 will be owned, operated, and maintained by Company.

RESIDENTIAL

3. Residential Single Family Homes

3.1. Extension Facilities will be installed to new Permanent residential applicants or groups of new Permanent residential applicants on an allowance under the following conditions:
   (A) A Line Extension Agreement signed by the applicant and construction costs in excess of the allowances, as described in 3.1(C) and 3.2 will be paid by the applicant before the Company begins installing facilities. Payment is due at the time the Line Extension Agreement is signed by the applicant.
   (B) The site plan has been approved and recorded in the county having jurisdiction.
   (C) The total cost of the Extension Facilities (primary, secondary, service), as determined by Company, is less than $10,000 per applicant.

3.2. All additional construction costs over $10,000 per applicant will be paid by applicant as a non-refundable contribution in aid of construction.

3.3. Applicants who combine to form a group may also combine their allowance as specified in Sections 3.1(C) and 3.2.

3.4. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project which will exclude the cost of one single-phase transformer.

3.5. The allowance cap of $10,000 will be reviewed from time to time with the Arizona Corporation Commission.

4. Residential Subdivision Developments

4.1. Extension Facilities will be installed to Residential Subdivision developments of four or more homes in advance of application for service by Permanent customers under the following conditions:
   (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of construction by the Company. Payment is due at the time the Line Extension Agreement is signed by the applicant.
   (B) The subdivision development plat has been approved and recorded in the county having jurisdiction. Applicant is responsible for providing Company an approved subdivision plat prior to project design. If the final approved plat is different from what was originally submitted to the Company, it may cause delays and additional cost for redesign.

4.2. The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

4.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per lot" allowance provisions of Section 4.6 and in accordance with Section 2.4.

4.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition or organizational structure of developer.

4.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights.

4.6. The refundable advance will be eligible for refund based on a "per lot" allowance of $3,500 for each Permanently connected residential customer over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date the Company executes the Line Extension Agreement with the applicant. A review of the project will be conducted annually to determine subdivision buildout, and if the qualifications have been met for any refunds.

4.7. Examples of the application of Section 4 can be found in Attachment 1 – Residential Subdivision Illustrative Example.

5. Residential "Lot Sale" Developments

5.1. Extension Facilities will be installed to residential "Lot Sale" developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The development plat has been approved and recorded in the county having jurisdiction.

5.2. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost Estimate.

5.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

5.4. Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

5.5. Extension Facilities will be installed to individual applicants in accordance with provisions listed in Section 3.

6. Master Planned Community Developments

6.1. Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by Permanent applicants under the following conditions:
   (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
   (B) The site development plan has been approved and recorded in the county having jurisdiction.

6.2. The cost of extending service to applicant will be determined by a Project-Specific Cost Estimate.

6.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

6.4. Extension Facilities will be installed to each subdivided tract within the planned development in accordance with the applicable sections of this Service Schedule 3.

7. Residential Multi-Family Developments

7.1. Extension Facilities will be installed to Residential Multi-Family Developments in advance of application for service by Permanent customers under the following conditions:
   (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
   (B) The site development plan has been approved and recorded in the county having jurisdiction.

7.2. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost estimate.

7.3. A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per unit" refundable allowance provisions of Section 7.6 and in accordance with Section 2.4.

7.4. In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond, based on the financial condition, or organizational structure of applicant.

7.5. That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as streetlights etc.

7.6. The refundable advance will be eligible for refund based on a "per unit" allowance of $1,000 for each new meter, installed for a permanent residential structure, over a five-year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement. A review of the project will be conducted annually to determine buildout and if the qualifications have been met for any refunds.

GENERAL SERVICE

8. General Service Provisions

8.1. Extension Facilities that do not meet the requirements under Residential Sections 3, 4, 5, 6, or 7 will be considered General Service and will be installed to all applicants who meet the qualifications under Sections 9, 10, 11, 12, 13, or 14 of this Service Schedule 3.

9. Basic General Service

9.1. Extension Facilities will be installed to Basic General Service in advance of application for service by Permanent applicants under the following conditions:
   (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
   (B) The site development plan for the project for which the Line Extension has been requested has been approved and recorded in the county having jurisdiction.

9.2. The project costs for Basic General Service installations will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or a combination of Schedule of Charges and Project-Specific Cost Estimate depending on the scope of the project.

9.3. The cost for Extension Facilities that require feeder, backbone, major infrastructure, or specialized equipment to serve the project, will be determined in accordance with a Project-Specific Cost Estimate.

9.4. Economic Feasibility Analysis for Basic General Service Applicants - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:
   (A) Project Cost $25,000 or less - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant

contributions such as street lights and other non-standard construction charges) is $25,000 or less will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) multiplied by six is equal to or greater than the cost of the applicant's Extension Facilities.

(B) Project Cost greater than $25,000 - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(C) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(D) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

(E) Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(F) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10. High Rise Developments

10.1. Extension Facilities will be installed to High Rise Developments in advance of application for service by Permanent applicants under the following conditions:

(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

(C) The residential units are individually metered or master metered in accordance with Section 21.

(D) Extension Facilities will be installed to designated points of delivery in accordance with APS' Electric Service Requirements Manual (ESRM). It is the applicant's responsibility to provide and maintain the electrical facilities within the building.

10.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

10.3. Economic Feasibility Analysis for High Rise Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:

(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year, and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10.4. Before Company orders specialized materials or equipment required to provide service, applicant will be required to make an advance payment to the Company for the

estimated cost of the material or equipment in accordance with Section 27.2.

11. Mixed-Use Developments

11.1. Extension Facilities will be installed to Mixed-Use Developments in advance of application for service by Permanent applicants under the following conditions:
(A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
(B) The site development plan has been approved and recorded in the county or city having jurisdiction.
(C) The residential units are individually metered or master metered in accordance with Section 21.

11.2. The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate and will be paid by the applicant before Company installing facilities.

11.3. Economic Feasibility Analysis for Mixed Use Developments - Applicants whose Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:
(A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than $25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.
(B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.
(C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the

unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

(D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

11.4. Before Company orders specialized materials or equipment required to provide service applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

12. Corporate Business & Industrial Park Developments

12.1. Extension Facilities will be made to Corporate Business and Industrial Park Developments in advance of application for service by Permanent customer under the following conditions:

(A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

(B) The site development plan has been approved and recorded in the county or city having jurisdiction.

12.2. The cost of installing Extension Facilities will be determined in accordance with a Project-Specific Cost Estimate.

12.3. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

12.4. Company will provide a “Conduit Only Design” provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

12.5. Extension Facilities will be installed to individual lots (at the request of an applicant) within the Corporate Business and Industrial Park Development in accordance with the applicable sections of this Service Schedule 3.

13. Temporary Applicants

13.1. Where Temporary Extension Facilities are required to provide service to the applicant, the applicant will make a non-refundable payment in advance of installation or construction equal to the cost of installing and removing of the facilities required in providing Temporary service, less the salvage value of such facilities. Charges will be determined by Company based on a Project-Specific Cost Estimate.

13.2. A Line Extension Agreement signed by the applicant and advance payment of all project

costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

13.3. When use of the Temporary service is discontinued or service is terminated, Company may dismantle and remove its facilities and the materials and equipment provided by Company will remain Company property.

14. Doubtful Permanency Customers

14.1. When, in the opinion of Company, permanency of the applicant's residence or operation is doubtful, the applicant will be required to pay the total cost of the Extension Facilities. The cost of extending service to applicant will be determined in accordance with a Project-Specific Cost Estimate. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for streetlights and other non-standard construction charges.

14.2. A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

OTHER CONDITIONS

15. Municipalities and Other Governmental Agencies

15.1. Extension Facility installations, relocations, or conversions of existing facilities required to serve loads of municipalities or other governmental agencies may be constructed before the receipt of a signed Line Extension Agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the Extension Facilities costs in accordance with the applicable sections of this Service Schedule 3.

15.2. The effective date for projects enacted under this provision for purposes of Section 2.4 will be the date the municipality or agency provided written approval to the Company to proceed with construction.

16. Change in Applicant's Service Requirements

16.1. Company will rebuild, modify, or upgrade its existing facilities to meet the applicant's added load, service entrance upgrade, or change in service requirements on the basis specified in Sections 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, or 14. Charges for such changes will be in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a Project-Specific Cost Estimate determined by the Company based on project-specific requirements.



SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

17. Relocations, Conversions and Upgrades of Company Facilities

17.1. **Relocations** - Company will relocate its facilities at the applicant's request. The cost of relocations not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) When the relocation of Company facilities involves "prior rights" conditions, the applicant will be required to make payment equal to the estimated cost of relocation as a non-refundable contribution in aid of construction. In addition, applicant will be required to provide similar "rights" for the relocated facilities.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by applicant.

17.2. **Conversions** - Company will convert from overhead to underground its facilities at applicant request. The cost of conversions not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate and may include residual value costs as computed in accordance with the method described in A.R.S. Section 40-347.

(A) The applicant will be required to make a payment equal to the estimated cost of conversion as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

17.3. **Upgrades** - Company will upgrade its facilities at applicant request. The cost of Company facility upgrades not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) The applicant will be required to make a payment equal to the estimated cost of the upgrade as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

18. Additional Primary Feed or Specialized Equipment

18.1. When specifically requested by an applicant to provide an alternate primary feed or specialized equipment (excluding transformation), Company will perform a special study to determine the feasibility of the request. The applicant will be required to pay for the cost of the additional feed requested as a non-refundable contribution in aid of construction. Installation cost will be based on a Project-Specific Cost Estimate. Payment for the installation of Extension Facilities is due at the time the Line Extension Agreement is signed by the applicant.

19. Unusual Circumstances

19.1. In unusual circumstances as determined by Company, when the application and provisions of this Service Schedule 3 appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when applicant's estimated demand load will exceed 3,000 kW, Company may make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

20. Abnormal Loads

20.1. Company, at its option, may install Extension Facilities to serve certain abnormal loads (such as transformer type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the applicant will be included in the payment described in previous sections of this Service Schedule 3.

21. Master Metering

21.1. **Mobile Home Parks** - Company will refuse service to all new construction or expansion of existing Permanent residential mobile home parks unless the construction or expansion is individually metered by Company.

21.2. **Residential Apartment Complexes, Condominiums** - Company will refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Arizona Administrative Code and the requirements discussed in 21.3 below. This section is not applicable under the following conditions:

(A) For Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care or;

(B) For Limited-Income Multi-Unit Residential Housing that uses solar power in a "behind-the-meter" application

21.3. **Multi-Unit High Rise Residential Developments** - Company will allow master metering for high rise residential units under the following conditions:

(A) The building will be served by a centralized heating, ventilation or air conditioning system.

(B) Each residential unit will be individually sub-metered and responsible for energy consumption of that unit.

(C) Sub-metering will be provided and maintained by the builder or homeowners association.

(D) Responsibility and methodology for determining each unit's energy billing will be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company before Company installing Extension Facilities.

21.4. **Conversion from master meter to individually metered system** - Company will convert its facilities from a master metered system to a permanent individually metered system at the applicant's request provided the applicant makes a non-refundable contribution in aid of construction equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended in accordance with the applicable sections of this Service Schedule 3. Applicant is responsible for all costs related to the installation of new service entrance equipment.

22. Voltage

22.1. All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the Extension Facilities are located. At the request of applicant, Company may, at its option, deliver service for special applications of non-standard or higher voltages with prior approval from Company's Engineering Department. Applicant will be required to pay the costs of any required studies as a non-refundable payment.

22.2. Extension Facilities installed at higher voltages will be limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or separated by public property or public right–of- way.

23. Point of Delivery

23.1. For overhead service, the point of delivery will be where Company's service conductors terminate at the applicant's weatherhead or bus riser.

23.2. For underground service, the point of delivery will be where Company's service conductors terminate in the applicant's or development's service equipment. The applicant will furnish, install and maintain any risers, raceways and termination cabinets necessary for the installation of Company's underground service conductors.

23.3. For special applications where service is provided at voltages higher than the standard voltages specified in the APS Electric Service Requirements Manual, Company and applicant will mutually agree upon the designated point of delivery.

24. Easements

24.1. Before Company begins construction of Extension Facilities, all suitable easements and rights-of-way required for any portion of the extension will be obtained by applicant and provided to Company in Company's name without cost to or condemnation by Company. All easements and rights-of-way obtained on behalf of Company will be on Company's standard easement form which contains the terms and conditions that are acceptable to Company.

25. Grade Modifications

25.1. If after construction of Extension Facilities, the final grade of the property established by the applicant is changed in such a way as to require relocation of Company facilities, or the applicant's actions or those of his contractor results in damage to such facilities, the cost of replacement, relocation, or any resulting repairs will be borne by applicant as a non-refundable contribution in aid of construction.

26. Measurement and Location

26.1. Measurement must be along the proposed route of construction.
26.2. Construction will be on public streets, roadways, highways, or easements acceptable to Company.
26.3. The Extension Facilities must be a branch from, the continuation of, or an addition to, Company's existing distribution facilities.

27. Agreements

27.1. **Study and Design Agreements** - Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company in an amount equal to the estimated cost of preparation. When the applicant authorizes Company to proceed with construction of the Extension Facilities, the payment will be credited to the cost of the Extension Facilities otherwise the payment will be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.
27.2. **Material Order Agreements** - Any applicant requesting Company to enter into a Line Extension Agreement or relocation agreement which requires either large quantities of material or material and equipment which the Company does not keep in stock will be required to make a payment to Company before the material being ordered in an amount equal to the material/equipment's estimated cost. When the applicant authorizes Company to proceed with construction of the extension, the payment will be

credited to the cost of the extension; otherwise, the payment will be non-refundable.

27.3. **Line Extension Agreements** - All facility installations or equipment upgrades requiring payment by an applicant will be in writing and signed by both the applicant and Company.

28. Applicant Construction of Company Distribution Facilities

28.1. Applicant may provide construction related labor only services associated with the installation of new distribution line facilities (21 kV and below) to serve the applicant's new or added load provided the applicant receives written approval from Company before performing any such services and uses electrical contractors who are qualified and licensed in the State of Arizona to construct such facilities and designated as an APS Approved Electrical Distribution Contractor.

28.2. This option is not available for the following:

(A) Replacement, modifications, upgrades, relocation, or conversions of existing systems.

(B) Where all or a portion of the distribution line facilities are to be constructed on or installed on existing distribution line or transmission lines.

28.3. All construction services provided by the applicant will be subject to inspection by a duly authorized Company representative and will comply with Company designs, construction standards, and other requirements which may be in effect at the time of construction. Any work found to be substandard in the sole opinion of the Company must be corrected by applicant before energization by Company.

28.4. Applicant will reimburse Company for all inspection and project coordination costs as a non-refundable contribution in aid of construction. Estimated costs for inspection and project coordination will be identified in the construction agreement executed by Company and applicant.

28.5. Costs for Extension Facilities for applicants who provide construction of Company distribution facilities will be based on a Project-Specific Cost Estimate.

28.6. A signed agreement and payment of all project costs minus labor are required before the start of applicant construction. Payment is due at the time the agreement is signed by the applicant.

28.7. For applicants that are not served by the terms in General Service Sections of this document, Company will provide a Project-Specific Cost Estimate. Applicants may submit an invoice detailing costs of Extension Facilities and apply any allowance provided in Residential Sections 3, 4, or 7 to these costs. At no point will these costs exceed the Company's Project-Specific Cost Estimate.

28.8. Applicants served by the terms in General Service Sections 9, 10, 11, 12, 13, or 14 of this document will be subject to the rules set forth in the respective section and Refund Section 2.4.

29. Settlement of Disputes

29.1. Any dispute between the applicant or prospective applicant and the Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may be referred to the Arizona Corporation Commission or a designated representative or employee for determination by either party.

30. Policy Exceptions

30.1. This Schedule 3 is applicable to all applicants unless specific exceptions are approved by the Arizona Corporation Commission.

(A) The following exceptions have been approved for Rural Municipality applicants:

i. Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of application for service by permanent applicants.

ii. The cost of installing Extension Facilities to Rural Municipal Business Developments will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project.

iii. The refund eligibility period for Rural Municipal Business Developments will be 7 years from the date the Company executes the Line Extension Agreement with the Rural Municipality applicant.

iv. Rural Municipal Business Development applicants will be required to advance payment of one-half of the project costs at the time the Line Extension Agreement is signed and before the start of Company construction. The balance of the project cost will be required 7 years from the Execution Date of the agreement if the project has not become economically feasible by the end of the 7th year refundable period. Any unrefunded advance balance paid at the start of the project, plus the balance of project costs due at the end of refund period, will become a non-refundable contribution in aid of construction 7 years from the Execution Date of the agreement.

v. Company may require a Surety Bond, Irrevocable Letter of Credit or Assignment of Monies in amount equal to any Advance not collected at the start of construction.

vi. The Economic Feasibility analysis for the Rural Municipal Business Development's Extension Facilities will be reviewed at the end of the third, fifth and seventh year of the Line Extension Agreement based on the average monthly demand within the Rural Municipal Business Development for the preceding year and to the degree that the average monthly demand supports

the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.

vii. Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

(B) The following exceptions for sections 3, 7, 9, 10, and 11 have been approved for Hopi and Navajo applicants for the extension of electric service to residential and commercial buildings within the Navajo Nation and the Hopi Reservation that are in the APS service territory.

i. APS distribution facilities will be extended up to 2,000 feet at no cost to such applicants.

ii. Applicants requiring distribution facilities extending more than 2,000 feet will pay the amount as calculated through the schedule of charges or project specific costs for any distribution facilities after the initial 2,000 feet from existing APS distribution consistent with the application sections of this schedule.

SCHEDULE OF CHARGES

Description	Rate	Unit
Single Family Underground	$ 11.47	Per foot
Single Family Overhead	$ 23.89	Per foot
Residential Subdivision*	$ 16.86	Per foot
General Service and Commercial, Single Phase, Underground	$ 21.05	Per foot
General Service and Commercial, Single Phase, Overhead	$ 33.46	Per foot
General Service and Commercial, Three Phase, Underground	$ 54.53	Per foot
General Service and Commercial, Three Phase, Overhead	$ 65.29	Per foot
Single Phase Pole Interset (pole set in existing line)	$ 7,133.39	Each
Three Phase Pole Interset (pole set in existing line)	$ 9,378.39	Each
*Residential Subdivision projects with 100 or more lots will be determined via project specific costs.		

Attachment 1
Residential Subdivision Illustrative Example

Scenario 1	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 2	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	100
Credited Allowance	$ 350,000
Potential Remaining Allowance	$ -

Scenario 3	
Number of Planned Homes	100
Estimated Construction Cost	$ 350,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ -
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

Scenario 4	
Number of Planned Homes	100
Estimated Construction Cost	$ 400,000
Total Potential Refundable Allowance	$ 350,000
Non-Refundable Contribution	$ 50,000
Number of Homes Completed	45
Credited Allowance	$ 157,500
Potential Remaining Allowance	$ 192,500

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

Terms and Conditions

The following Terms and Conditions and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (APS or Company). These Terms and Conditions are considered a part of all service schedules and rate schedules including but not limited to rider and adjustor schedules, except where specifically excluded or changed by a written agreement. For a Customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required. If there is a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule apply.

1. **Application for Service**

Before supplying service, APS will verify the identity of Applicant. Applicant may be required to appear at the Company's place of business to produce proof of identity, sign an application, or execute a contract for service before APS supplies service. If there is no signed application or contract for service, APS's standard contract terms apply and the supplying of Standard Offer or Direct Access services and the Customer's acceptance of service forms a service agreement between APS and the Customer for delivery, acceptance, and payment for services.

1.1 **Grounds for Refusal of Service** – APS may refuse service if any of the following conditions exist:

(A) The Applicant has an outstanding amount due with APS for the same class of service and is unwilling to make payment arrangements that are acceptable to the Company.

(B) A condition exists that, in the Company's judgment, is unsafe or hazardous.

(C) The Applicant has failed to meet the Company's security-deposit requirements outlined in Section 3.

(D) The Applicant is known to be in violation of a Company Tariff.

(E) The Applicant fails to furnish the funds, service, equipment, rights-of-way or easements required to serve the Applicant that APS has specified as a condition for providing service.

(F) The Applicant falsifies his or her identity for the purpose of obtaining service.

(G) Service is already being provided at the address for which the Applicant is requesting service.

(H) A prior Customer, who will reside at or benefit from service at the Applicant's Premises, owes APS a delinquent bill for the same class of service from the same or a prior service address.

(I) The Applicant previously resided at or benefited from the same class of service at the Applicant's Premises during the period the outstanding balance was incurred, and the Applicant is unwilling to make arrangements with APS for payment.

~~(H)~~i. Applicants for residential service may demonstrate that they are not responsible for all or a portion of the prior balance associated with the Applicant's Premises by demonstrating, to APS's reasonable satisfaction, that the Applicant paid their proportional share of the balance owed to APS for electric service during the period they resided at the Applicant's Premises.

~~(I)~~(J) The Applicant has failed to obtain any required permit or inspection indicating that the Applicant's facilities comply with current local construction and safety codes.

2. **Service Establishment**

A Service Establishment Charge of $0.00 for residential or $0.00 non-residential plus applicable adjustments will be assessed each time APS is asked to establish or re-establish electric service, or to make a special read without a disconnect and calculate a bill for a partial month. All service establishment requests are subject to availability; there is no guarantee that the Company will have the ability to provide service establishment, re-establishment, or reconnection of service on same-day requests or requests made outside of regular business hours. For situations where the Company is unable to complete same-day or after-hours requests, service establishment will be scheduled for the next available business day.

2.1 **Multiple Connects** – If multiple connects are performed during the same site visit, in the same Applicant name, at the same address, and for the same class of service, APS will assess the Service Establishment Charge once for every two Delivery Points.

2.2 **After-hours Connect** – The Customer must also pay an after-hours charge plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203(~~.~~D~~.~~)(3), be established or re-established after 5:00 p.m. on a day other than the day of request. The after-hours charge will be $0.00 for residential with standard

metering, $0.00 plus applicable adjustments for residential with non-standard metering or $164.00 plus applicable adjustments for non-residential.

2.3 **Same-Day Connect** – The Customer must also pay a same-day connect charge of $0.00 plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203(~~.~~D)~~.~~(3), be established or re-established on the same business day the request is being made, and APS agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by APS on that day. APS may, where no additional costs are incurred by the Company, waive the same-day fee.

2.4 **Non-Standard Service Request** – The Customer must also pay $164.00 plus applicable adjustments per crew-person per hour when the Customer requests services that do not meet the definition of Service Establishment as defined in A.A.C. R14-2-203(~~.~~D)(~~.~~3) and that require the availability of Company representatives after-hours, on a weekend day, or on a Company holiday. Examples of non-standard service requests are Customer-requested outages for maintenance and metering-equipment installations that include instrument transformers. The number of representatives the Company uses to fulfill a request is in the Company's sole discretion. Customers will be given notice of estimated charges before the work is performed.

2.5 **Waiving of Service Establishment Charge** – The Company may waive the Service Establishment Charge if:

(A) The establishment of service is effective with the last Meter read date billed and a field trip is not required because Applicant accepts responsibility for energy billed and not yet paid.

(B) Applicant has an active Landlord Automatic Transfer of Service Agreement on file with the Company.

3. **Establishing Credit, Security Deposits and other forms of Credit Assurance**
When credit cannot be established as provided for in Section 3.1 and 3.2 or when it is determined that the Applicant left an unpaid final bill owed to another utility company, the Applicant will be required to provide a security deposit to secure payment of bills for service.

3.1 **Residential Establishment of Credit** – APS will not require a security deposit from a new Applicant for service at a primary or secondary residence if the Applicant can meet any of the following requirements:

(A) The Applicant has had service of a comparable nature with APS within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months or been disconnected for nonpayment.

(B) The Company receives an acceptable credit rating, as determined by the Company, for the Applicant from a credit-rating agency used by the Company.

(C) The Applicant can produce a letter regarding verification of credit from an electric utility that provided service of a comparable nature to the Applicant within six months of the current date, and the utility states that the Applicant had a timely payment history for the prior 12 consecutive months.

(D) If, in lieu of a security deposit, the Company receives an acceptable deposit-guarantee notification from a social or governmental agency or a surety bond in a sum equal to the required deposit.

3.2 **Nonresidential Establishment of Credit** – All nonresidential Applicants will be required to place a cash deposit to secure payment of bills for service, unless:

(A) The Applicant had service of a comparable nature with the Company within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months and was not disconnected for nonpayment.

(B) The Applicant provides a noncash security deposit in the form of a surety bond, irrevocable letter of credit, or assignment of monies in an amount equal to the required security deposit.

3.3 **General Deposits Guidelines** – If a security deposit is required, a separate deposit may be required for each service location.

(A) A Customer's security deposit will not preclude the Company from terminating an agreement for service or suspending service if the Customer fails to meet service-agreement obligations.

(B) The Company may choose to accept less than the full deposit required at the time service is established based on the Customer's financial condition.

(C) A security deposit may increase or decrease if the Customer's average consumption increases or decreases by more than 10% for residential accounts or 5% for nonresidential accounts within 12 consecutive months and credit has not been established.

(D) Where three or more additional residential services are requested, the Company may require the Customer to establish or reestablish a security deposit.

3.4 **Residential Security Deposits –** Residential security deposits will not exceed two times the Customer's average monthly bill as estimated by the Company. APS may require a residential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within a 12 consecutive month period or has been disconnected for non-payment during the last 12 months.

3.5 **Nonresidential Security Deposits –** Nonresidential security deposits will not exceed two- and-one-half times the Customer's maximum monthly billing as estimated by the Company. APS may require a nonresidential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within 12 consecutive months or if the Customer has been disconnected for nonpayment during the last 12 months, or when the Customer's financial condition may jeopardize the payment of the bill, as determined by the Company based on the results of using a credit-scoring worksheet. The Company will inform all Customers of the Arizona Corporation Commission's complaint process should the Customer dispute the deposit based on the financial data.

3.6 **Deposit Interest –** Cash deposits held by APS six months (183 days or longer) earn interest from the date the deposit was collected at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website.

3.7 **Deposit Refunds –** If the Customer terminates all service with the Company, the Customer's security deposit may be credited to any remaining final bills. Any remaining credit balance will be refunded to the Customer of record within 30 days of the Customer's final bill due date.

3.8 **Residential security deposits** or other instruments of credit will automatically expire or be credited or returned to the Customer's account after 12 consecutive months of service, if the Customer has not been delinquent in payments more than twice and the Customer has not filed bankruptcy in the last 12 months.

3.9 **Nonresidential security deposits** and noncash deposits on file with the Company will be reviewed after 24 months of service and will be returned if:

(A) The Customer has not been delinquent in payments more than twice, has not been disconnected for non-payment, and has not filed for bankruptcy during the previous 12 consecutive months; and

(B) The Customer's financial condition does not warrant an extension of the security deposit.

4. **Rates**

The Customer's service characteristics and service requirements determine the selection of the applicable rate schedule.

4.1 **Rate Selection** – APS will use reasonable care in initially establishing service to the Customer under the most advantageous rate schedule applicable to the Customer. Because of varying Customer usage patterns and other reasons beyond APS's reasonable knowledge or control, the Company cannot guarantee that the most economic applicable rate will be applied. APS will not make any refunds in any instance where it is determined that the Customer would have paid less for service had the Customer been billed on an alternate rate or provision of that rate.

4.2 **Rate Information** – APS will make available, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to the Customer for the requested type of service. In addition, APS will notify its Customers of any changes in the Company's Tariff affecting those Customers.

4.3 **Optional Rates** – Optional rate schedules are available for certain classes of service. After establishing service, a Customer may choose an alternate rate schedule effective from the next regularly scheduled Meter reading, after the appropriate metering equipment is reprogramed or installed. For non-residential customers, no further rate schedule changes may be made within the succeeding 12-month period. If the rate schedule or contract under which the Customer is provided service specifies a term, the Customer may not exercise its option to select an alternate rate schedule until expiration of that term.

4.4 The Company may, at its discretion, place a Customer on an available rate schedule (consistent with the existing meter's ability to measure service) while the Company seeks satisfactory and unassisted access to the Company's equipment if the Customer refuses to allow meter access. Please also see 7.3(E).

5. **Billing**

Billing Periods for service normally consist of approximately 30 days unless otherwise designated under rate schedules, through contractual agreement, or at the Company's option.

5.1 **Payment of Bills** – The Customer is responsible for paying bills until service is ordered discontinued and the Company has had reasonable time to secure a final Meter reading for those services involving energy usage, or, if nonmetered services

are involved, until the Company has had reasonable time to process the disconnect request.

5.2 **Failure to Receive Bills or Notices** (including notices of disconnection) which have been properly placed in the United States mail to the Customer's last address on file or sent by or through alternative methods of communications, such as electronic mail to the Customer's last email address on file, will not prevent such bills from becoming delinquent or prevent the notices from being effective, or relieve the Customer of their obligations.

~~5.3 **Incentive for Electronic Payments –** A monthly incentive of $0.48 per Customer will be given to Customers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.~~

~~5.4~~5.3 **Billing Errors –** When an error is found in the billing sent to the Customer, APS will correct the error to recover or refund the difference between the original billing and the correct billing. Adjusted billings will not be sent for periods beyond the applicable statute of limitations from the date the error is discovered.

~~5.5~~5.4 **Corrected Charges for Overbilling –** Refunds or credits to Customers resulting from overbillings will be made promptly upon discovery by the Company.

~~5.6~~5.5 **Corrected Charges for Underbilling –** Except as specified below, corrected charges for underbillings will be limited to three months for residential accounts and six months for nonresidential accounts. Customers will be given an equal length of time, such as the number of months underbilled, to pay the backbill without late-payment penalties. Where the account is billed on a special contract or nonmetered rate, corrected charges for underbillings will be billed in accordance with the contract or rate-schedule requirements and will not be limited to three or six months.

(A) Where service has been established but no bills have been rendered, corrected charges for underbillings will go back to the date service was established.

(B) Where there is evidence of Meter Tampering or energy diversions, corrected charges for underbillings will go back to the date Meter Tampering or energy diversions began, as determined by the Company, and APS is not required to give an equal length of time, such as the number of months underbilled, to pay the backbill. APS will work with the Customer to establish a payment plan that is acceptable to the Company.

(C) Where lack of access to the Meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings will go back to the Billing Month of the last Company-obtained Meter-read date.

(D) Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event may such rebilling exceed the applicable statute of limitations.

~~5.7~~5.6 The Company may forgo correcting a billing error if the amount over or under billed is de minimis and the cost of rebilling does not justify the cost and time required to rebill.

6. **Collection Policy**

The following collection policies apply to all Customer accounts:

6.1 **Delinquent Bills –** All bills rendered by the Company are due and payable no later than 21 calendar days from the billing date. Any payment not received within this time frame is delinquent. All delinquent accounts, for which payment has not been received, are subject to the provisions of the Company's termination procedure. The Company may suspend or terminate a Customer's service for nonpayment of any Arizona Corporation Commission approved charges.

6.2 **Late Charges –** All delinquent charges, including past due security deposits, are subject to a late charge at the rate of 18% per annum (1.5% per month) plus applicable adjustments.

6.3 **Transfer of Outstanding Bills –** If a Customer has two or more services with APS and one or more services are terminated for any reason leaving an outstanding bill, and the Customer is unwilling to make payment arrangements that are acceptable to the Company, the Company may transfer the balance due on the terminated service to any other active account of the Customer for the same class of service. The Customer's failure to pay the active account will result in the suspension or termination of service. If service is requested by two or more individuals, the Company has the right to collect the full amount owed from any one of the Customers.

6.4 **Dishonored Payments –** If the Company is notified by the Customer's financial institution that it will not honor a payment tendered by the Customer for payment of any bill, the Company may require the Customer to make payment in cash, or by money order, certified or cashier's check, or other means that guarantee the Customer's payment to the Company.

(A) The Customer will be charged a fee of $15.00 plus applicable adjustments for each instance where the Customer's payment is not honored by the Customer's financial institution.

(B) The Company will waive the $15.00 Dishonored Payment fee if the Customer has not, in the previous 12 months, had a dishonored payment.

(C) The tender of a dishonored payment does not relieve the Customer of the obligation to pay the Company under the original terms of the bill, nor does it defer the Company's right to terminate the Customer's service for nonpayment of bill(s).

(D) Where the Customer has tendered two or more dishonored payments in the past 12 consecutive months, the Company may require the Customer to make payment in cash, or money order or cashier's check for the next 12 consecutive months.

6.5 **Collection Agency Referrals** – All unpaid delinquent final bills may be referred to a collection agency for collection. If collection-agency referral is warranted, the Customer may be responsible for the associated collection-agency fees incurred.

7. **Termination of Service**

7.1 To avoid termination of service: The Customer will make payment in full, including any necessary deposit as outlined in Section 3, or make payment arrangements that are satisfactory to the Company.

7.2 If service is terminated, APS will not restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Company. APS may also require payment of Same-Day and After-Hours charges prior to restoring service.

7.3 **Termination of Service with Notice** – APS may, without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, if the Company has met the notice requirements established by the Arizona Corporation Commission.~~.~~

(A) The Customer's violation of any applicable rules of the Arizona Corporation Commission or Company Tariff.

(B) The Customer's failure to pay a Delinquent Bill for services provided by Company.

(C) The Customer's breach of a written contract for service.

(D) The Customer's failure to comply with the Company's deposit requirements.
(E) The Customer's failure to provide the Company with satisfactory and unassisted access to the Company's equipment.
(F) When necessary to comply with an order of any governmental agency having jurisdiction.
(G) A prior Customer's failure to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the Premises.
(H) Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.
(I) The Company learns of the existence of any condition in Section 1.1 - Grounds For Refusal of Service.
(J) When the Company learns of the unauthorized resale of utility equipment or services by the Customer.

7.4 **Termination of Service Without Notice** – Notwithstanding subsections 7.1, 7.3, 7.5, and 7.7, the Company may, without liability for injury or damage, disconnect service to any Customer without advance notice under any of the following conditions:

(A) An obvious hazard to the safety or health of the Customer, the general population or the utility's personnel or facilities;
(B) The Company has evidence of Meter Tampering or fraud related to the Customer or the service address; or
(C) The Customer fails to comply with the curtailment procedures imposed by the Company during a supply shortage.

7.5 **Termination of Service for Dishonored Payment** – Before reconnecting service, payment of funds resulting from a dishonored payment and all other delinquent amounts will be required in cash, money order, certified funds, or cashier's check. If Customer has already received a final notice of disconnection at the time the bill became past due, APS may, without liability for injury or damage, disconnect service without additional notice under any of the following conditions:

(A) When the Customer makes payments to avoid or stop disconnection with a dishonored payment and has already received a notice at the time the bill became past due.
(B) When the Customer pays to reconnect service with a dishonored payment and has already received a notice at the time the bill became past due.

7.6 **Termination Charges** – The Company will require payment of a Field Call Charge of $0.00 plus applicable adjustments when an authorized Company representative travels to the Customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements, or terminate the service. This charge only applies for field calls resulting from the termination process.

(A) If a termination is required at the pole the reconnection charge will be $89.00 plus applicable adjustments.

(B) If a termination is in underground equipment the reconnection charge will be $135.00 plus applicable adjustments.

7.7 **Residential Service Termination Process**

(A) Except as provided in subsection 7.4, the Company shall not disconnect residential service to a Customer:

(1) From June 1 through October 15;

(2) If the Customer has paid at least half of the Customer's Delinquent Bill balance within the last 25 days;

(3) Due to a Customer's failure to pay the disputed portion of a bill if the Customer has complied with A.A.C. Rl4-2-212(B);

(4) If the Customer's Delinquent Bill balance is less than or equal to $300.00; or

(5) If the Customer can establish, on an annual basis, through medical documentation that, in the opinion of a licensed medical practitioner:

a. Termination would be especially dangerous to the health of the Customer or a permanent resident residing at the Customer's service address; or

b. If life support equipment used in the home is dependent on utility service for operation of such apparatus.

(B) At least 48 hours before the date upon which termination for failure to pay is scheduled to occur, the Company shall have completed:

(1) Providing at least two written notices of the termination to the customer, and if applicable, the customer's designated third party, by using First Class Mail, email, or both, depending on the listed customer contact information provided to APS; and

(2) Providing an additional communication by using any of the listed customer contact information provided to APS, and, if applicable, the customer's designated third party, to provide additional notice of the termination. The listed customer contact information may include, but is not limited to,

email, text, or telephone. APS may provide notifications via text messages to the customer and their designated third party, provided that the Company allow the option to "opt out" of text messaging at any time.

(C) The Company shall provide notice of the following to a Customer, and if applicable, the customer's designated third party, whose service would be disconnected except for subsection 7.7(A)(1).
  (1) The Customer would have been disconnected if not for subsection 7.7(A)(1);
  (2) The reason the Company is not permitted to disconnect service;
  (3) The Customer's continued financial responsibility for the charges accruing to the account for energy used;
  (4) The potential actions the Customer may take to prevent the disconnection of service when subsection 7.7(A)(1) no longer applies; and
  (5) The requirement to enter into a payment plan as specified in subsection (D).

(D) The Company shall not disconnect residential service unless the Company's office is open to the public on the day of disconnection and the day following the day of disconnection.

(E) A Customer with a Delinquent Bill balance of over $75 whose service disconnection was prevented by subsection 7.7(A)(1) shall be automatically placed on a six-month deferred payment arrangement prior to beginning the service termination process. The Company shall not impose any late fees or interest on any past due amounts that accrued during the no disconnect period.

(F) If a residential Customer is delinquent on an account and has a cash deposit with the Company, the Company shall use the deposit to pay the delinquent amount before disconnecting service, then allow the Customer time to repay the deposit in installments over a period of six months.

8. **Metering & Metering Equipment**

8.1 **Standard Metering –** The Company's standard method of measuring energy usage is through the use of Automated Metering Infrastructure (AMI) metering equipment. All Customers will be served using the Company's standard metering equipment unless:

(A) The Customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used; or

(B) The Customer meets all eligibility requirements for non-standard metering and requests non-standard metering.

8.2 **Non-Standard Metering** – The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and must be read manually each month. Certain optional rates may not be available to Customers who select a non-standard meter.

8.3 **Non-Standard Metering Eligibility** – Only residential Customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or Customers with newly installed rooftop solar, are not eligible for non-standard metering.

8.4 **Non-Standard Metering Charges** – The following charges will apply when a Customer requests, and is granted, non-standard metering as described in Section 8.1(B):

(A) Monthly Meter Reading Charge: $5.00

(B) Non-Standard Metering Set-up Fee: A $50.00 one-time charge for Customers with existing AMI meter.

(C) Customers in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used [see Section 8.1(A)] will not be billed a non-standard meter reading charge.

8.5 **Discontinuation of Non-Standard Metering** – The Company may replace a non-standard meter with a standard meter, without notifying the Customer prior to replacement, under any of the following conditions:

(A) The Company employees observe or have evidence of a safety hazard to employees, Customers, or the Company's or Customer property.

(B) The Company employees observe or have evidence of meter tampering, energy diversion, or fraud.

(C) The Company has evidence of unauthorized resale of electricity.

(D) The Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to the Company equipment, and physical threats such as weapons or dogs.

All terms and conditions in Section 7, regarding termination of service, will also apply.

8.6 **Measuring Customer Service** – All energy sold to the Customer by the Company will be measured by commercially acceptable measuring devices. Where it is impractical to meter loads, such as street lighting, security lighting, or special

installations, consumption will be determined by the Company. The readings of the Meter will be conclusive as to the amount of electric power supplied to the Customer unless there is evidence of Meter Tampering or energy diversion or unless a test reveals the Meter is in error by more than 3%, either fast or slow.

8.7 **Meter Rereads** – When requested by a Customer, APS will reread the Customer's Meter within 10 working days after the request. The cost of each reread is $14.00 plus applicable adjustments if the original reading was not in error.

8.8 **Meter Testing** – APS tests its Meters regularly in accordance with a Meter testing and maintenance program approved by the Arizona Corporation Commission. APS will individually test a Company owned and maintained Meter upon a Customer's request. If after testing, a Meter is found to be more than 3% in error, either fast or slow, correction will be made of previous readings and adjusted bills will be rendered.

8.9 **Meter Test Charge** – If the Meter is found to be within the plus or minus 3% limit, the Company may charge the Customer $44.00 plus applicable adjustments for a Customer-requested Meter test if the Meter is removed from the site and tested in the meter shop, or $93.00 plus applicable adjustments if the Meter remains on site and is tested in the field.

(A) The Company will waive the Meter Test Charge if the Customer has not, within the previous 12 months, requested a meter test that was found to be within the plus or minus 3% limit.

8.10 **Meter Tampering** – If there is evidence of Meter Tampering or energy diversion, the Customer, person, or entity demonstrated to have tampered with the Meter, or benefited from the tampering or diversion, will be billed for the estimated energy and, if applicable, Demand, for the period in which the energy diversion took place. Additionally, where there is evidence of Meter Tampering, energy diversion, or by-passing the Meter, the Customer, person or entity demonstrated to have tampered with the Meter or diverted energy will also be charged the cost of the investigation as determined by the Company.

9. **Service Installations & Metering** – The Customer's service installation will normally be arranged to accept only one type of service at one Point of Delivery to enable service measurement through one Meter. If the Customer requires more than one type of service, or total service cannot be measured through one Meter according to the Company's regular practice, separate Meters will be used and separate billing rendered for the service measured by each Meter.

9.1 **Customer Equipment** – The Customer must install and maintain all wiring and equipment beyond the Point of Delivery except for the Company's Meters and special equipment. The Customer's entire installation must conform to all applicable construction standards and safety codes, and the Customer must furnish an inspection or permit if required by law or by the Company. In circumstances where a clearance is not required by law, the Company may require the Customer to execute a Letter In-Lieu of Electrical Clearance. The Customer must also provide, in accordance with APS's current service standards and Electric Service Requirements Manual, at no expense to the Company, and close to the Point of Delivery, a space that is, in the Company's opinion, both suitable and sufficient for installing, accessing and maintaining the Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line on the Company's website.

9.2 **Special Meter-Reading Device** – Where a Customer requests, and the Company approves, a special Meter-reading device or communications services or devices to accommodate the Customer's needs, the cost for the additional equipment and usage fees are the Customer's responsibility.

9.3 **Totalized Metering and Billing** – The Company normally meters and bills each site separately. But, at the Customer's request, adjacent and contiguous sites (not separated by private or public property or right of way), operated as one integral unit under the same name and as a part of the same business, may at the Company's option, be considered a single site as specified in the Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

9.4 **Service Connections** – The Company is not required to install or maintain any lines and equipment on the Customer's side of the Point of Delivery except its Meter.

(A) For overhead service, the Point of Delivery is where the Company's service conductors terminate at the Customer's weatherhead or bus rider.

(B) For underground service, the Point of Delivery is where the Company's service conductors terminate in the Customer's or development's service equipment. The Customer must furnish, install, and maintain any risers, raceways, or termination cabinet necessary for installing the Company's underground service conductors.

(C) For special Applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements

Manual, the designated Point of Delivery must be mutually agreed on by the parties.

(D) For the mutual protection of the Customer and the Company, only authorized employees or agents of the Company are permitted to make and energize the connection between the Company's service wires and the Customer's service entrance conductors. APS employees must carry the Company-issued identification that they will show on request.

10. **Customer Obligations**

10.1 **Load Characteristics** – The Customer must exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine-wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Demand, do not impair service to other Customers or interfere with operating any telephone, television, or other communication facilities. Customers must meet power factor requirements as specified in the applicable rate schedules.

10.2 **Easements** – All suitable Easements or rights-of---way required by the Company for any portion used to serve Customer(s), which are either on sites owned, leased, or otherwise controlled by the Customer(s) or developer(s), or other property required for the Company's use, will be furnished in the Company's name by the Customer(s) without cost to or condemnation by the Company and in reasonable time to meet proposed service requirements. All Easements or rights-of---way granted to, or obtained on behalf of, the Company will contain terms and conditions that are acceptable to the Company. Notwithstanding the terms of a written Easement or right-of-way, when the Company discovers that a Customer or the Customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, adjacent to or within an Easement or right-of-way or adjacent to Company-owned equipment, and the work, construction, vegetation, or facility poses a hazard, or violates federal, state, or local laws, ordinances, statutes, rules, or regulations, or significantly interferes with the Company's safe use, operation, or maintenance of, or access to, equipment, or facilities, the Company will notify the Customer or the Customer's agent and may take whatever actions are necessary to eliminate the hazard, obstruction, interference, or violation at the Customer's expense. The Company will notify the Customer in writing before taking such action.

10.3 **Access for Repair, Maintenance and Service Restoration** – The Company's authorized agents must have satisfactory unassisted, 24-hour-a-day, seven days a

week access to the Company's equipment located on the Customer's sites for the purpose of repair, maintenance, and service-restoration work that the Company may need to perform.

10.4 **Access for Install, Inspect, Read, or Remove –** The Company's authorized agents must have satisfactory unassisted access to the Customer's sites at all hours to install, inspect, read, or remove its Meters or to install, operate, or maintain other Company property, to verify that Customer is in compliance with its obligations, or to inspect and determine the connected electrical load.

10.5 **Trip Charge –** A trip charge of $22.00 for residential or $26.00 for non-residential, plus applicable adjustments will be assessed each time an authorized Company representative travels to a site and is unable to complete a Customer's service request because of lack of access to the Point of Delivery.

(A) The Company will waive the Trip Charge if, within the last 12 months, there have not been any instances where an authorized Company representative traveled to a site and was unable to complete the Customer's service request because of lack of access to the Point of Delivery.

10.6 **Six Months No Access –** If the Company, in its opinion, does not have satisfactory unassisted access to the Meter after six months (not necessarily consecutive) of good-faith efforts to work with the Customer, then the Company has sufficient cause to terminate service or deny any rate options where, in the Company's opinion, access is required.

10.7 **Remedies –** The remedy for unassisted access will be at APS's discretion and may include the installation by the Company of a specialized Meter. If a specialized Meter is installed, the Customer will be billed the difference between the otherwise applicable Meter for the Customer's rate and the specialized Meter plus the cost incurred to install the specialized Meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, APS verification of unassisted access will be required before service is restored. Written termination notice is required before disconnecting service under this section.

11. **Company Obligations**

11.1 **Customer-Specific Information –** Customer-specific information will not be released without the Customer's specific prior written authorization unless the information is requested by a law-enforcement or other public agency, or is

requested by the Arizona Corporation Commission or its staff, or is reasonably required for legitimate account-collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with the Company if the goods or services will help the Company to provide efficient, effective, safe, or reliable service; and the contract includes a requirement that the information be kept confidential and be used only to fulfill the supplier's obligations to the Company.

11.2 **Service Voltage** – The Company will deliver electric service to the designated Point of Delivery, as specified in Section 9.4 of this Schedule, at the standard voltages specified in the Company's Electric Service Requirements Manual and as specified in A.A.C. R14-2-208(F). The Company may deliver service for special applications at higher voltages, with prior approval from the Company's Engineering Department and in accordance with the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services approved by the Arizona Corporation Commission.

12. **Limitations on Liability of Company**

12.1 **General Liability**

(A) The Company will not be responsible for any third-party claims against the Company that arise from a Customer's use of the Company's electric services or the Company's provision of electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

(B) A Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

(C) Except in the case of the Company's willful misconduct or gross negligence, the Company will not be liable to a Customer or any other party for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of, or related to, establishing, furnishing,

rearranging, moving, terminating, or changing the service or facilities or equipment, except that for an interruption of service to a Customer, to the extent resulting from error, mistake, omission, interruption or delay by the Company, the Company's liability, if any, to the Customer shall not exceed an amount equal to the charges for service applicable under the Company's Rates (calculated on a proportionate basis where appropriate) for the period of service interruption.

(D) In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue, loss of current or prospective business opportunities, lost profits and lost rent) of any kind whatsoever regardless of the cause or foreseeability thereof.

(E) The Company will not be responsible on any occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

12.2 **Service Interruptions**

(A) The Company will make reasonable provisions to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 12.3(A), a Public Safety Power Shutoff (PSPS) event, or to any other cause that the Company could not have reasonably foreseen and made provision against, or that in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission or distribution equipment, to eliminate the possibility of damage to the Company's property or to the person or property of others, or otherwise address threats to public health or safety.

(B) In the event of a service interruption, including but not limited to, a planned, unplanned, or PSPS outage, the Company may provide notice to customers, and if applicable, the customer's designated third party, by using any of the listed customer contact information provided to APS. The listed customer contact information may include, but is not limited to, email, text, or telephone. APS may provide notifications via text messages to the customer and their designated third party, provided

that the Company allow the option to "opt out" of text messaging at any time

(C) Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this interruption or limitation will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

(D) The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

(E) In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

(F) The use of electric energy upon the Customer's Premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

12.3 **Force Majeure**

(A) Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

(1) flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

(2) accident or explosion;

(3) war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

(4) acts of God;

(5) interference of civil and/or military authorities;

(6) strikes, lockouts or other labor difficulties;

(7) vandalism, sabotage or malicious mischief;

(8) usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

(9) breakage, failure, or accidents to equipment or facilities; or

(10) lack, limitation or loss of electrical or fuel supply; or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

(B) A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

(C) Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

13. **Successors and Assigns –** Agreements for Service are binding on and for the benefit of the successors and assigns of the Customer and the Company, but no assignments by the Customer are effective until the Customer's assignee agrees in writing to be bound and until the assignment is accepted in writing by the Company.

14. **Warranty –** There are no understanding, agreements, representations, or warranties, expressed or implied (including warranties regarding merchantability or fitness for a particular purpose), not specified here or in the applicable rules of the Arizona Corporation Commission concerning the sale and delivery of services by the Company to the Customer. These Terms and Conditions and the applicable rules of the Arizona Corporation Commission state the entire obligation of the Company in connection with sales and deliveries.

15. **Direct Access Service** – *NOTE: Retail Electric Competition is currently on hold in APS Service Territory.*

15.1 **Direct Access Service Request (DASR) –** A Direct Access Service Request charge of $10.00 plus any applicable adjustments will be assessed to the Electric Service Provider (ESP submitting the DASR each time the Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.

15.2 **Direct Access Service** – Direct Access Service will be effective upon the next Meter read date if DASR is processed 15 calendar days before that read date and the appropriate metering equipment is in place. If a DASR is made less than 15 calendar days before the next regular read date, the effective date will be at the next Meter read date. The above timeframes are applicable for Customers

changing their selection of ESP or for Customers returning to Standard Offer service.

(A) Any Customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Arizona Corporation Commission. The Customer will not be eligible for Direct Access service for the succeeding 12 months.

(B) If a Customer returning to Standard Offer Service, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will apply only if the Customer fails to select another ESP within 60 days of returning to Standard Offer Service.

(C) Unpaid charges incurred before the Customer selects Direct Access Service will not delay the Customer's request for Direct Access Service. These charges remain the responsibility of the Customer to pay. Normal collection activity, including discontinuing service, may result from failure to pay.

(D) Where the ESP is the MSP or MRSP, and the ESP or its' agent fails to provide the Meter data to the Company under the Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, the Company may, at its option, obtain the data or estimate the billing determinants.

(E) Where the Company is the MRSP, the Company will, at the request of the Customer or the ESP, reread or test the Customer's Meter within 10 working days after the request. The cost of each reread or test may be applied to the Customer or ESP when applicable.

(F) All energy sold to the Customer by MRSP will be measured by commercially acceptable measuring devices and under the terms and conditions of the Company's Schedule 10 - Terms and Conditions for Direct Access.

15.3 **Direct Access Deposits –** If the Customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount that reflects the portion of the Customer's service being provided by a Load Serving ESP. If the Load Serving ESP is providing ESP Consolidated Billing under the Company's Schedule 10 Section 7, the entire deposit will be credited to the Customer's account; or, if the Customer chooses to change from Direct Access to Standard

Offer service, the requested deposit amount may be increased by an amount under Section 3.3 which reflects that the Company is providing bundled electric service.

15.4 **Direct Access and Company Equipment**

(A) **Meters –** A Meter Service Provider (MSP) or its authorized agents may remove the Company's metering equipment under the Company's Schedule 10 Terms and Conditions for Direct Access. Meters not returned to the Company or returned damaged will result in charge(s) to the MSP of the replacement costs, plus an administration fee of 15%, less five year's depreciation.

(B) **Lock-rings –** The Company will lease lock-ring keys to MSP's or their agents who are authorized to remove Company Meters under the terms and conditions of the Company's Schedule 10 at a refundable charge of $70.00 plus applicable adjustments per key. The charge will not be refunded if a key is lost, stolen, or damaged. If the Company must replace 10% of the issued keys within any 12-month period because of loss by the MSP's agent, the Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock-ring keys must be returned to the Company within five working days if the MSP or its authorized agents are:

(1) No longer permitted to remove Company Meters under the conditions of the Company's Schedule 10;

(2) No longer authorized by the Arizona Corporation Commission to provide services; or

(3) The ESP Agreement has been terminated.

(C) **Site Meetings –** If the MSP, the Customer, or the Customer's agent requests a joint site meeting for removal of Company metering and associated equipment or lock ring, a base charge of $62.00 plus applicable adjustments per site will be assessed. The Company may assess an additional charge of $53.00 plus applicable adjustments per hour for joint site meetings that exceed 30 minutes. If the Company must temporarily replace the MSP's Meter or associated metering equipment during emergency situations or to restore power to a Customer, the above charges may apply.

DEFINITIONS

Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

Billing Date is the date the statement was created either in electronic or paper form as shown on the bill regardless of the postmark, mailing, or electronic transmittal date.

Billing Month means the period between any two regular readings of the utility's Meters at approximately 30-day intervals. [A.A.C. R14-2-201-(5)]

Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

Company Holidays (as referred to in section 2.4) are New Year's Day, Martin Luther King Jr. Day, President's Day Memorial Day, Juneteenth, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, the day after Thanksgiving, Christmas Eve, Christmas Day, and New Year's Eve.

Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]

Delinquent Bill means a bill in which current electric charges are considered past due (22 *calendar* days after the statement date).

Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(13)]

Distribution Lines means the utility lines operated at distribution voltages which are constructed along public roadways or other bona fide rights-of-way, including Easements on a Customer's property. [A.A.C. R-14-2-201-(14)]

Easement means the right to use land owned by another party by grant or as allowed by law. An easement gives the Company the right to have Company lines or facilities on property not owned by the Company. This allows the Company to build, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity and for other purposes. The owner may continue to use the land in the easement as provided by a written easement or by law.

Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer ("Landlord") and the Company, that provides continuous and uninterrupted service to the Landlord during intervals when a Landlord has no tenants. A Service Establishment Charge will not apply, and service will automatically be transferred into the Landlord's name. Landlord Automatic Transfer of Service Agreements are available to property owners that have established credit with the Company.

Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(27)]

Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(29)]

Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from the Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(30)]

Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(31)]

On-site means on a single Premises served by the Company's facilities.

Premises means all of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by alleys, canals, streets, railways, or other public rights-of-way.

Public Safety Power Shutoff (PSPS) means an event where the Company temporarily shuts off electric service within a specific area when extreme weather and other environmental conditions create an elevated wildfire risk such that proactive service interruption becomes necessary to help protect public health and safety and/or prevent damage to person(s) or property. The purpose of a PSPS event is to reduce the risk of wildfires caused by ignition from tree strikes, downed wires, equipment failures, or other events exacerbated by high-risk wildfire conditions in the environment (including, without limitation, relative high temperatures, low humidity, precipitation conditions, wind speeds and gusting, terrain, fuel complexity and moisture, or other acts of the elements that contribute to heightened wildfire risk in a given location).

Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C. R14-2-201(35)]

Working Day means a weekday (during normal business hours) that is not designated as a Company holiday.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

Statement of Charges		
Description	**Charge**	**Reference**
Residential Service Establishment Charge	$0.00	2
Nonresidential Service Establishment Charge	$0.00	2
After hours Charge – Residential Standard Metering	$0.00	2.2
After hours Charge – Residential Non-Standard Metering	$0.00	2.2
After hours Charge – Nonresidential	$164.00	2.2
Same Day Connect Charge	$0.00	2.3
Non-Standard Service Request Charge (per crew person, per hour)	$164.00	2.4
~~Electronically Transmitted Payment Discount~~	~~($0.48)~~	~~5.3~~
Dishonored Payment Fee	$15.00	6.4
Field Call Charge	$0.00	7.6
Overhead Reconnection Charge	$89.00	7.6
Underground Reconnection Charge	$135.00	7.6
Non-Standard Metering – Monthly Meter Reading	$5.00	8.4
Non-Standard Metering Set-up fee for customer with existing AMI meter	$50.00	8.4
Meter Reread	$14.00	8.7
Meter test in shop	$44.00	8.9
Meter test at site	$93.00	8.9
Trip Charge – Residential	$22.00	10.5
Trip Charge – Nonresidential	$26.00	10.5

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

Terms and Conditions

The following Terms and Conditions and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (APS or Company). These Terms and Conditions are considered a part of all service schedules and rate schedules including but not limited to rider and adjustor schedules, except where specifically excluded or changed by a written agreement. For a Customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required. If there is a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule apply.

1. **Application for Service**

Before supplying service, APS will verify the identity of Applicant. Applicant may be required to appear at the Company's place of business to produce proof of identity, sign an application, or execute a contract for service before APS supplies service. If there is no signed application or contract for service, APS's standard contract terms apply and the supplying of Standard Offer or Direct Access services and the Customer's acceptance of service forms a service agreement between APS and the Customer for delivery, acceptance, and payment for services.

1.1 **Grounds for Refusal of Service** – APS may refuse service if any of the following conditions exist:

(A) The Applicant has an outstanding amount due with APS for the same class of service and is unwilling to make payment arrangements that are acceptable to the Company.

(B) A condition exists that, in the Company's judgment, is unsafe or hazardous.

(C) The Applicant has failed to meet the Company's security-deposit requirements outlined in Section 3.

(D) The Applicant is known to be in violation of a Company Tariff.

(E) The Applicant fails to furnish the funds, service, equipment, rights-of-way or easements required to serve the Applicant that APS has specified as a condition for providing service.

(F) The Applicant falsifies his or her identity for the purpose of obtaining service.

(G) Service is already being provided at the address for which the Applicant is requesting service.

(H) A prior Customer, who will reside at or benefit from service at the Applicant's Premises, owes APS a delinquent bill for the same class of service from the same or a prior service address.

(I) The Applicant previously resided at or benefited from the same class of service at the Applicant's Premises during the period the outstanding balance was incurred, and the Applicant is unwilling to make arrangements with APS for payment.

i. Applicants for residential service may demonstrate that they are not responsible for all or a portion of the prior balance associated with the Applicant's Premises by demonstrating, to APS's reasonable satisfaction, that the Applicant paid their proportional share of the balance owed to APS for electric service during the period they resided at the Applicant's Premises.

(J) The Applicant has failed to obtain any required permit or inspection indicating that the Applicant's facilities comply with current local construction and safety codes.

2. **Service Establishment**

A Service Establishment Charge of $0.00 for residential or $0.00 non-residential plus applicable adjustments will be assessed each time APS is asked to establish or re-establish electric service, or to make a special read without a disconnect and calculate a bill for a partial month. All service establishment requests are subject to availability; there is no guarantee that the Company will have the ability to provide service establishment, re-establishment, or reconnection of service on same-day requests or requests made outside of regular business hours. For situations where the Company is unable to complete same-day or after-hours requests, service establishment will be scheduled for the next available business day.

2.1 **Multiple Connects –** If multiple connects are performed during the same site visit, in the same Applicant name, at the same address, and for the same class of service, APS will assess the Service Establishment Charge once for every two Delivery Points.

2.2 **After-hours Connect –** The Customer must also pay an after-hours charge plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203(D)(3), be established or re-established after 5:00 p.m. on a day other than the day of request. The after-hours charge will be $0.00 for residential with standard

metering, $0.00 plus applicable adjustments for residential with non-standard metering or $164.00 plus applicable adjustments for non-residential.

2.3 **Same-Day Connect** – The Customer must also pay a same-day connect charge of $0.00 plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203(D)(3), be established or re-established on the same business day the request is being made, and APS agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by APS on that day. APS may, where no additional costs are incurred by the Company, waive the same-day fee.

2.4 **Non-Standard Service Request** – The Customer must also pay $164.00 plus applicable adjustments per crew-person per hour when the Customer requests services that do not meet the definition of Service Establishment as defined in A.A.C. R14-2-203(D)(3) and that require the availability of Company representatives after-hours, on a weekend day, or on a Company holiday. Examples of non-standard service requests are Customer-requested outages for maintenance and metering-equipment installations that include instrument transformers. The number of representatives the Company uses to fulfill a request is in the Company's sole discretion. Customers will be given notice of estimated charges before the work is performed.

2.5 **Waiving of Service Establishment Charge** – The Company may waive the Service Establishment Charge if:

(A) The establishment of service is effective with the last Meter read date billed and a field trip is not required because Applicant accepts responsibility for energy billed and not yet paid.

(B) Applicant has an active Landlord Automatic Transfer of Service Agreement on file with the Company.

3. **Establishing Credit, Security Deposits and other forms of Credit Assurance**
When credit cannot be established as provided for in Section 3.1 and 3.2 or when it is determined that the Applicant left an unpaid final bill owed to another utility company, the Applicant will be required to provide a security deposit to secure payment of bills for service.

3.1 **Residential Establishment of Credit** – APS will not require a security deposit from a new Applicant for service at a primary or secondary residence if the Applicant can meet any of the following requirements:

(A) The Applicant has had service of a comparable nature with APS within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months or been disconnected for nonpayment.

(B) The Company receives an acceptable credit rating, as determined by the Company, for the Applicant from a credit-rating agency used by the Company.

(C) The Applicant can produce a letter regarding verification of credit from an electric utility that provided service of a comparable nature to the Applicant within six months of the current date, and the utility states that the Applicant had a timely payment history for the prior 12 consecutive months.

(D) If, in lieu of a security deposit, the Company receives an acceptable deposit-guarantee notification from a social or governmental agency or a surety bond in a sum equal to the required deposit.

3.2 **Nonresidential Establishment of Credit** – All nonresidential Applicants will be required to place a cash deposit to secure payment of bills for service, unless:

(A) The Applicant had service of a comparable nature with the Company within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months and was not disconnected for nonpayment.

(B) The Applicant provides a noncash security deposit in the form of a surety bond, irrevocable letter of credit, or assignment of monies in an amount equal to the required security deposit.

3.3 **General Deposits Guidelines** – If a security deposit is required, a separate deposit may be required for each service location.

(A) A Customer's security deposit will not preclude the Company from terminating an agreement for service or suspending service if the Customer fails to meet service-agreement obligations.

(B) The Company may choose to accept less than the full deposit required at the time service is established based on the Customer's financial condition.

(C) A security deposit may increase or decrease if the Customer's average consumption increases or decreases by more than 10% for residential accounts or 5% for nonresidential accounts within 12 consecutive months and credit has not been established.

(D) Where three or more additional residential services are requested, the Company may require the Customer to establish or reestablish a security deposit.

3.4 **Residential Security Deposits –** Residential security deposits will not exceed two times the Customer's average monthly bill as estimated by the Company. APS may require a residential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within a 12 consecutive month period or has been disconnected for non-payment during the last 12 months.

3.5 **Nonresidential Security Deposits –** Nonresidential security deposits will not exceed two- and-one-half times the Customer's maximum monthly billing as estimated by the Company. APS may require a nonresidential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within 12 consecutive months or if the Customer has been disconnected for nonpayment during the last 12 months, or when the Customer's financial condition may jeopardize the payment of the bill, as determined by the Company based on the results of using a credit-scoring worksheet. The Company will inform all Customers of the Arizona Corporation Commission's complaint process should the Customer dispute the deposit based on the financial data.

3.6 **Deposit Interest –** Cash deposits held by APS six months (183 days or longer) earn interest from the date the deposit was collected at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website.

3.7 **Deposit Refunds –** If the Customer terminates all service with the Company, the Customer's security deposit may be credited to any remaining final bills. Any remaining credit balance will be refunded to the Customer of record within 30 days of the Customer's final bill due date.

3.8 **Residential security deposits** or other instruments of credit will automatically expire or be credited or returned to the Customer's account after 12 consecutive months of service, if the Customer has not been delinquent in payments more than twice and the Customer has not filed bankruptcy in the last 12 months.

3.9 **Nonresidential security deposits** and noncash deposits on file with the Company will be reviewed after 24 months of service and will be returned if:

(A) The Customer has not been delinquent in payments more than twice, has not been disconnected for non-payment, and has not filed for bankruptcy during the previous 12 consecutive months; and

(B) The Customer's financial condition does not warrant an extension of the security deposit.

4. **Rates**

The Customer's service characteristics and service requirements determine the selection of the applicable rate schedule.

4.1 **Rate Selection** – APS will use reasonable care in initially establishing service to the Customer under the most advantageous rate schedule applicable to the Customer. Because of varying Customer usage patterns and other reasons beyond APS's reasonable knowledge or control, the Company cannot guarantee that the most economic applicable rate will be applied. APS will not make any refunds in any instance where it is determined that the Customer would have paid less for service had the Customer been billed on an alternate rate or provision of that rate.

4.2 **Rate Information** – APS will make available, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to the Customer for the requested type of service. In addition, APS will notify its Customers of any changes in the Company's Tariff affecting those Customers.

4.3 **Optional Rates** – Optional rate schedules are available for certain classes of service. After establishing service, a Customer may choose an alternate rate schedule effective from the next regularly scheduled Meter reading, after the appropriate metering equipment is reprogramed or installed. For non-residential customers, no further rate schedule changes may be made within the succeeding 12-month period. If the rate schedule or contract under which the Customer is provided service specifies a term, the Customer may not exercise its option to select an alternate rate schedule until expiration of that term.

4.4 The Company may, at its discretion, place a Customer on an available rate schedule (consistent with the existing meter's ability to measure service) while the Company seeks satisfactory and unassisted access to the Company's equipment if the Customer refuses to allow meter access. Please also see 7.3(E).

5. **Billing**

Billing Periods for service normally consist of approximately 30 days unless otherwise designated under rate schedules, through contractual agreement, or at the Company's option.

5.1 **Payment of Bills** – The Customer is responsible for paying bills until service is ordered discontinued and the Company has had reasonable time to secure a final Meter reading for those services involving energy usage, or, if nonmetered services

are involved, until the Company has had reasonable time to process the disconnect request.

5.2 **Failure to Receive Bills or Notices** (including notices of disconnection) which have been properly placed in the United States mail to the Customer's last address on file or sent by or through alternative methods of communications, such as electronic mail to the Customer's last email address on file, will not prevent such bills from becoming delinquent or prevent the notices from being effective, or relieve the Customer of their obligations.

5.3 **Billing Errors** – When an error is found in the billing sent to the Customer, APS will correct the error to recover or refund the difference between the original billing and the correct billing. Adjusted billings will not be sent for periods beyond the applicable statute of limitations from the date the error is discovered.

5.4 **Corrected Charges for Overbilling** – Refunds or credits to Customers resulting from overbillings will be made promptly upon discovery by the Company.

5.5 **Corrected Charges for Underbilling** – Except as specified below, corrected charges for underbillings will be limited to three months for residential accounts and six months for nonresidential accounts. Customers will be given an equal length of time, such as the number of months underbilled, to pay the backbill without late-payment penalties. Where the account is billed on a special contract or nonmetered rate, corrected charges for underbillings will be billed in accordance with the contract or rate-schedule requirements and will not be limited to three or six months.

(A) Where service has been established but no bills have been rendered, corrected charges for underbillings will go back to the date service was established.

(B) Where there is evidence of Meter Tampering or energy diversions, corrected charges for underbillings will go back to the date Meter Tampering or energy diversions began, as determined by the Company, and APS is not required to give an equal length of time, such as the number of months underbilled, to pay the backbill. APS will work with the Customer to establish a payment plan that is acceptable to the Company.

(C) Where lack of access to the Meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings will go back to the Billing Month of the last Company-obtained Meter-read date.

(D) Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event may such rebilling exceed the applicable statute of limitations.

5.6 The Company may forgo correcting a billing error if the amount over or under billed is de minimis and the cost of rebilling does not justify the cost and time required to rebill.

6. **Collection Policy**

The following collection policies apply to all Customer accounts:

6.1 **Delinquent Bills –** All bills rendered by the Company are due and payable no later than 21 calendar days from the billing date. Any payment not received within this time frame is delinquent. All delinquent accounts, for which payment has not been received, are subject to the provisions of the Company's termination procedure. The Company may suspend or terminate a Customer's service for nonpayment of any Arizona Corporation Commission approved charges.

6.2 **Late Charges –** All delinquent charges, including past due security deposits, are subject to a late charge at the rate of 18% per annum (1.5% per month) plus applicable adjustments.

6.3 **Transfer of Outstanding Bills –** If a Customer has two or more services with APS and one or more services are terminated for any reason leaving an outstanding bill, and the Customer is unwilling to make payment arrangements that are acceptable to the Company, the Company may transfer the balance due on the terminated service to any other active account of the Customer for the same class of service. The Customer's failure to pay the active account will result in the suspension or termination of service. If service is requested by two or more individuals, the Company has the right to collect the full amount owed from any one of the Customers.

6.4 **Dishonored Payments –** If the Company is notified by the Customer's financial institution that it will not honor a payment tendered by the Customer for payment of any bill, the Company may require the Customer to make payment in cash, or by money order, certified or cashier's check, or other means that guarantee the Customer's payment to the Company.

(A) The Customer will be charged a fee of $15.00 plus applicable adjustments for each instance where the Customer's payment is not honored by the Customer's financial institution.

(B) The Company will waive the $15.00 Dishonored Payment fee if the Customer has not, in the previous 12 months, had a dishonored payment.

(C) The tender of a dishonored payment does not relieve the Customer of the obligation to pay the Company under the original terms of the bill, nor does it defer the Company's right to terminate the Customer's service for nonpayment of bill(s).

(D) Where the Customer has tendered two or more dishonored payments in the past 12 consecutive months, the Company may require the Customer to make payment in cash, or money order or cashier's check for the next 12 consecutive months.

6.5 **Collection Agency Referrals –** All unpaid delinquent final bills may be referred to a collection agency for collection. If collection-agency referral is warranted, the Customer may be responsible for the associated collection-agency fees incurred.

7. **Termination of Service**

7.1 To avoid termination of service: The Customer will make payment in full, including any necessary deposit as outlined in Section 3, or make payment arrangements that are satisfactory to the Company.

7.2 If service is terminated, APS will not restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Company. APS may also require payment of Same-Day and After-Hours charges prior to restoring service.

7.3 **Termination of Service with Notice –** APS may, without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, if the Company has met the notice requirements established by the Arizona Corporation Commission.

(A) The Customer's violation of any applicable rules of the Arizona Corporation Commission or Company Tariff.

(B) The Customer's failure to pay a Delinquent Bill for services provided by Company.

(C) The Customer's breach of a written contract for service.

(D) The Customer's failure to comply with the Company's deposit requirements.

(E) The Customer's failure to provide the Company with satisfactory and unassisted access to the Company's equipment.

(F) When necessary to comply with an order of any governmental agency having jurisdiction.

(G) A prior Customer's failure to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the Premises.

(H) Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.

(I) The Company learns of the existence of any condition in Section 1.1 - Grounds For Refusal of Service.

(J) When the Company learns of the unauthorized resale of utility equipment or services by the Customer.

7.4 **Termination of Service Without Notice –** Notwithstanding subsections 7.1, 7.3, 7.5, and 7.7, the Company may, without liability for injury or damage, disconnect service to any Customer without advance notice under any of the following conditions:

(A) An obvious hazard to the safety or health of the Customer, the general population or the utility's personnel or facilities;

(B) The Company has evidence of Meter Tampering or fraud related to the Customer or the service address; or

(C) The Customer fails to comply with the curtailment procedures imposed by the Company during a supply shortage.

7.5 **Termination of Service for Dishonored Payment –** Before reconnecting service, payment of funds resulting from a dishonored payment and all other delinquent amounts will be required in cash, money order, certified funds, or cashier's check. If Customer has already received a final notice of disconnection at the time the bill became past due, APS may, without liability for injury or damage, disconnect service without additional notice under any of the following conditions:

(A) When the Customer makes payments to avoid or stop disconnection with a dishonored payment and has already received a notice at the time the bill became past due.

(B) When the Customer pays to reconnect service with a dishonored payment and has already received a notice at the time the bill became past due.

7.6 **Termination Charges –** The Company will require payment of a Field Call Charge of $0.00 plus applicable adjustments when an authorized Company representative travels to the Customer's site to accept payment on a delinquent account, notify of

service termination, make payment arrangements, or terminate the service. This charge only applies for field calls resulting from the termination process.

(A) If a termination is required at the pole the reconnection charge will be $89.00 plus applicable adjustments.

(B) If a termination is in underground equipment the reconnection charge will be $135.00 plus applicable adjustments.

7.7 **Residential Service Termination Process**

(A) Except as provided in subsection 7.4, the Company shall not disconnect residential service to a Customer:

(1) From June 1 through October 15;

(2) If the Customer has paid at least half of the Customer's Delinquent Bill balance within the last 25 days;

(3) Due to a Customer's failure to pay the disputed portion of a bill if the Customer has complied with A.A.C. Rl4-2-212(B);

(4) If the Customer's Delinquent Bill balance is less than or equal to $300.00; or

(5) If the Customer can establish, on an annual basis, through medical documentation that, in the opinion of a licensed medical practitioner:

a. Termination would be especially dangerous to the health of the Customer or a permanent resident residing at the Customer's service address; or

b. If life support equipment used in the home is dependent on utility service for operation of such apparatus.

(B) At least 48 hours before the date upon which termination for failure to pay is scheduled to occur, the Company shall have completed:

(1) Providing at least two written notices of the termination to the customer, and if applicable, the customer's designated third party, by using First Class Mail, email, or both, depending on the listed customer contact information provided to APS; and

(2) Providing an additional communication by using any of the listed customer contact information provided to APS, and, if applicable, the customer's designated third party, to provide additional notice of the termination. The listed customer contact information may include, but is not limited to, email, text, or telephone. APS may provide notifications via text messages to the customer and their designated third party, provided that the Company allow the option to "opt out" of text messaging at any time.

(C) The Company shall provide notice of the following to a Customer, and if applicable, the customer's designated third party, whose service would be disconnected except for subsection 7.7(A)(1).
  (1) The Customer would have been disconnected if not for subsection 7.7(A)(1);
  (2) The reason the Company is not permitted to disconnect service;
  (3) The Customer's continued financial responsibility for the charges accruing to the account for energy used;
  (4) The potential actions the Customer may take to prevent the disconnection of service when subsection 7.7(A)(1) no longer applies; and
  (5) The requirement to enter into a payment plan as specified in subsection (D).

(D) The Company shall not disconnect residential service unless the Company's office is open to the public on the day of disconnection and the day following the day of disconnection.

(E) A Customer with a Delinquent Bill balance of over $75 whose service disconnection was prevented by subsection 7.7(A)(1) shall be automatically placed on a six-month deferred payment arrangement prior to beginning the service termination process. The Company shall not impose any late fees or interest on any past due amounts that accrued during the no disconnect period.

(F) If a residential Customer is delinquent on an account and has a cash deposit with the Company, the Company shall use the deposit to pay the delinquent amount before disconnecting service, then allow the Customer time to repay the deposit in installments over a period of six months.

8. **Metering & Metering Equipment**

8.1 **Standard Metering –** The Company's standard method of measuring energy usage is through the use of Automated Metering Infrastructure (AMI) metering equipment. All Customers will be served using the Company's standard metering equipment unless:

  (A) The Customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used; or

  (B) The Customer meets all eligibility requirements for non-standard metering and requests non-standard metering.

8.2 **Non-Standard Metering –** The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and

must be read manually each month. Certain optional rates may not be available to Customers who select a non-standard meter.

8.3 **Non-Standard Metering Eligibility –** Only residential Customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or Customers with newly installed rooftop solar, are not eligible for non-standard metering.

8.4 **Non-Standard Metering Charges** – The following charges will apply when a Customer requests, and is granted, non-standard metering as described in Section 8.1(B):

(A) Monthly Meter Reading Charge: $5.00

(B) Non-Standard Metering Set-up Fee: A $50.00 one-time charge for Customers with existing AMI meter.

(C) Customers in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used [see Section 8.1(A)] will not be billed a non-standard meter reading charge.

8.5 **Discontinuation of Non-Standard Metering –** The Company may replace a non-standard meter with a standard meter, without notifying the Customer prior to replacement, under any of the following conditions:

(A) The Company employees observe or have evidence of a safety hazard to employees, Customers, or the Company's or Customer property.

(B) The Company employees observe or have evidence of meter tampering, energy diversion, or fraud.

(C) The Company has evidence of unauthorized resale of electricity.

(D) The Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to the Company equipment, and physical threats such as weapons or dogs.

All terms and conditions in Section 7, regarding termination of service, will also apply.

8.6 **Measuring Customer Service –** All energy sold to the Customer by the Company will be measured by commercially acceptable measuring devices. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by the Company. The readings of the Meter will be conclusive as to the amount of electric power supplied to the

Customer unless there is evidence of Meter Tampering or energy diversion or unless a test reveals the Meter is in error by more than 3%, either fast or slow.

8.7 **Meter Rereads** – When requested by a Customer, APS will reread the Customer's Meter within 10 working days after the request. The cost of each reread is $14.00 plus applicable adjustments if the original reading was not in error.

8.8 **Meter Testing** – APS tests its Meters regularly in accordance with a Meter testing and maintenance program approved by the Arizona Corporation Commission. APS will individually test a Company owned and maintained Meter upon a Customer's request. If after testing, a Meter is found to be more than 3% in error, either fast or slow, correction will be made of previous readings and adjusted bills will be rendered.

8.9 **Meter Test Charge** – If the Meter is found to be within the plus or minus 3% limit, the Company may charge the Customer $44.00 plus applicable adjustments for a Customer-requested Meter test if the Meter is removed from the site and tested in the meter shop, or $93.00 plus applicable adjustments if the Meter remains on site and is tested in the field.

(A) The Company will waive the Meter Test Charge if the Customer has not, within the previous 12 months, requested a meter test that was found to be within the plus or minus 3% limit.

8.10 **Meter Tampering** – If there is evidence of Meter Tampering or energy diversion, the Customer, person, or entity demonstrated to have tampered with the Meter, or benefited from the tampering or diversion, will be billed for the estimated energy and, if applicable, Demand, for the period in which the energy diversion took place. Additionally, where there is evidence of Meter Tampering, energy diversion, or by-passing the Meter, the Customer, person or entity demonstrated to have tampered with the Meter or diverted energy will also be charged the cost of the investigation as determined by the Company.

9. **Service Installations & Metering** – The Customer's service installation will normally be arranged to accept only one type of service at one Point of Delivery to enable service measurement through one Meter. If the Customer requires more than one type of service, or total service cannot be measured through one Meter according to the Company's regular practice, separate Meters will be used and separate billing rendered for the service measured by each Meter.

9.1 **Customer Equipment** – The Customer must install and maintain all wiring and equipment beyond the Point of Delivery except for the Company's Meters and

special equipment. The Customer's entire installation must conform to all applicable construction standards and safety codes, and the Customer must furnish an inspection or permit if required by law or by the Company. In circumstances where a clearance is not required by law, the Company may require the Customer to execute a Letter In-Lieu of Electrical Clearance. The Customer must also provide, in accordance with APS's current service standards and Electric Service Requirements Manual, at no expense to the Company, and close to the Point of Delivery, a space that is, in the Company's opinion, both suitable and sufficient for installing, accessing and maintaining the Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line on the Company's website.

9.2 **Special Meter-Reading Device –** Where a Customer requests, and the Company approves, a special Meter-reading device or communications services or devices to accommodate the Customer's needs, the cost for the additional equipment and usage fees are the Customer's responsibility.

9.3 **Totalized Metering and Billing –** The Company normally meters and bills each site separately. But, at the Customer's request, adjacent and contiguous sites (not separated by private or public property or right of way), operated as one integral unit under the same name and as a part of the same business, may at the Company's option, be considered a single site as specified in the Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

9.4 **Service Connections –** The Company is not required to install or maintain any lines and equipment on the Customer's side of the Point of Delivery except its Meter.

(A) For overhead service, the Point of Delivery is where the Company's service conductors terminate at the Customer's weatherhead or bus rider.

(B) For underground service, the Point of Delivery is where the Company's service conductors terminate in the Customer's or development's service equipment. The Customer must furnish, install, and maintain any risers, raceways, or termination cabinet necessary for installing the Company's underground service conductors.

(C) For special Applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, the designated Point of Delivery must be mutually agreed on by the parties.

(D) For the mutual protection of the Customer and the Company, only authorized employees or agents of the Company are permitted to make and energize the connection between the Company's service wires and the Customer's service entrance conductors. APS employees must carry the Company-issued identification that they will show on request.

10. **Customer Obligations**

10.1 **Load Characteristics** – The Customer must exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine-wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Demand, do not impair service to other Customers or interfere with operating any telephone, television, or other communication facilities. Customers must meet power factor requirements as specified in the applicable rate schedules.

10.2 **Easements** – All suitable Easements or rights-of---way required by the Company for any portion used to serve Customer(s), which are either on sites owned, leased, or otherwise controlled by the Customer(s) or developer(s), or other property required for the Company's use, will be furnished in the Company's name by the Customer(s) without cost to or condemnation by the Company and in reasonable time to meet proposed service requirements. All Easements or rights-of---way granted to, or obtained on behalf of, the Company will contain terms and conditions that are acceptable to the Company. Notwithstanding the terms of a written Easement or right-of-way, when the Company discovers that a Customer or the Customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, adjacent to or within an Easement or right-of-way or adjacent to Company-owned equipment, and the work, construction, vegetation, or facility poses a hazard, or violates federal, state, or local laws, ordinances, statutes, rules, or regulations, or significantly interferes with the Company's safe use, operation, or maintenance of, or access to, equipment, or facilities, the Company will notify the Customer or the Customer's agent and may take whatever actions are necessary to eliminate the hazard, obstruction, interference, or violation at the Customer's expense. The Company will notify the Customer in writing before taking such action.

10.3 **Access for Repair, Maintenance and Service Restoration** – The Company's authorized agents must have satisfactory unassisted, 24-hour-a-day, seven days a week access to the Company's equipment located on the Customer's sites for the

purpose of repair, maintenance, and service-restoration work that the Company may need to perform.

10.4 **Access for Install, Inspect, Read, or Remove** – The Company's authorized agents must have satisfactory unassisted access to the Customer's sites at all hours to install, inspect, read, or remove its Meters or to install, operate, or maintain other Company property, to verify that Customer is in compliance with its obligations, or to inspect and determine the connected electrical load.

10.5 **Trip Charge** – A trip charge of $22.00 for residential or $26.00 for non-residential, plus applicable adjustments will be assessed each time an authorized Company representative travels to a site and is unable to complete a Customer's service request because of lack of access to the Point of Delivery.

(A) The Company will waive the Trip Charge if, within the last 12 months, there have not been any instances where an authorized Company representative traveled to a site and was unable to complete the Customer's service request because of lack of access to the Point of Delivery.

10.6 **Six Months No Access** – If the Company, in its opinion, does not have satisfactory unassisted access to the Meter after six months (not necessarily consecutive) of good-faith efforts to work with the Customer, then the Company has sufficient cause to terminate service or deny any rate options where, in the Company's opinion, access is required.

10.7 **Remedies** – The remedy for unassisted access will be at APS's discretion and may include the installation by the Company of a specialized Meter. If a specialized Meter is installed, the Customer will be billed the difference between the otherwise applicable Meter for the Customer's rate and the specialized Meter plus the cost incurred to install the specialized Meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, APS verification of unassisted access will be required before service is restored. Written termination notice is required before disconnecting service under this section.

11. **Company Obligations**

11.1 **Customer-Specific Information** – Customer-specific information will not be released without the Customer's specific prior written authorization unless the information is requested by a law-enforcement or other public agency, or is requested by the Arizona Corporation Commission or its staff, or is reasonably

required for legitimate account-collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with the Company if the goods or services will help the Company to provide efficient, effective, safe, or reliable service; and the contract includes a requirement that the information be kept confidential and be used only to fulfill the supplier's obligations to the Company.

11.2 **Service Voltage** – The Company will deliver electric service to the designated Point of Delivery, as specified in Section 9.4 of this Schedule, at the standard voltages specified in the Company's Electric Service Requirements Manual and as specified in A.A.C. R14-2-208(F). The Company may deliver service for special applications at higher voltages, with prior approval from the Company's Engineering Department and in accordance with the Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services approved by the Arizona Corporation Commission.

12. **Limitations on Liability of Company**

12.1 **General Liability**

(A) The Company will not be responsible for any third-party claims against the Company that arise from a Customer's use of the Company's electric services or the Company's provision of electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

(B) A Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

(C) Except in the case of the Company's willful misconduct or gross negligence, the Company will not be liable to a Customer or any other party for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of, or related to, establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or

equipment, except that for an interruption of service to a Customer, to the extent resulting from error, mistake, omission, interruption or delay by the Company, the Company's liability, if any, to the Customer shall not exceed an amount equal to the charges for service applicable under the Company's Rates (calculated on a proportionate basis where appropriate) for the period of service interruption.

(D) In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue, loss of current or prospective business opportunities, lost profits and lost rent) of any kind whatsoever regardless of the cause or foreseeability thereof.

(E) The Company will not be responsible on any occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

12.2 **Service Interruptions**

(A) The Company will make reasonable provisions to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 12.3(A), a Public Safety Power Shutoff (PSPS) event, or to any other cause that the Company could not have reasonably foreseen and made provision against, or that in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission or distribution equipment, to eliminate the possibility of damage to the Company's property or to the person or property of others, or otherwise address threats to public health or safety.

(B) In the event of a service interruption, including but not limited to, a planned, unplanned, or PSPS outage, the Company may provide notice to customers, and if applicable, the customer's designated third party, by using any of the listed customer contact information provided to APS. The listed customer contact information may include, but is not limited to, email, text, or telephone. APS may provide notifications via text messages to the customer and their designated third party, provided

that the Company allow the option to "opt out" of text messaging at any time

(C) Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this interruption or limitation will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

(D) The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

(E) In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

(F) The use of electric energy upon the Customer's Premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

12.3 **Force Majeure**

(A) Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

(1) flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;
(2) accident or explosion;
(3) war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;
(4) acts of God;
(5) interference of civil and/or military authorities;
(6) strikes, lockouts or other labor difficulties;
(7) vandalism, sabotage or malicious mischief;
(8) usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;
(9) breakage, failure, or accidents to equipment or facilities; or

(10) lack, limitation or loss of electrical or fuel supply; or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

(B) A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

(C) Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

13. **Successors and Assigns –** Agreements for Service are binding on and for the benefit of the successors and assigns of the Customer and the Company, but no assignments by the Customer are effective until the Customer's assignee agrees in writing to be bound and until the assignment is accepted in writing by the Company.

14. **Warranty –** There are no understanding, agreements, representations, or warranties, expressed or implied (including warranties regarding merchantability or fitness for a particular purpose), not specified here or in the applicable rules of the Arizona Corporation Commission concerning the sale and delivery of services by the Company to the Customer. These Terms and Conditions and the applicable rules of the Arizona Corporation Commission state the entire obligation of the Company in connection with sales and deliveries.

15. **Direct Access Service** – *NOTE: Retail Electric Competition is currently on hold in APS Service Territory.*

15.1 **Direct Access Service Request (DASR) –** A Direct Access Service Request charge of $10.00 plus any applicable adjustments will be assessed to the Electric Service Provider (ESP submitting the DASR each time the Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.

15.2 **Direct Access Service** – Direct Access Service will be effective upon the next Meter read date if DASR is processed 15 calendar days before that read date and the appropriate metering equipment is in place. If a DASR is made less than 15 calendar days before the next regular read date, the effective date will be at the next Meter read date. The above timeframes are applicable for Customers

changing their selection of ESP or for Customers returning to Standard Offer service.

(A) Any Customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Arizona Corporation Commission. The Customer will not be eligible for Direct Access service for the succeeding 12 months.

(B) If a Customer returning to Standard Offer Service, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will apply only if the Customer fails to select another ESP within 60 days of returning to Standard Offer Service.

(C) Unpaid charges incurred before the Customer selects Direct Access Service will not delay the Customer's request for Direct Access Service. These charges remain the responsibility of the Customer to pay. Normal collection activity, including discontinuing service, may result from failure to pay.

(D) Where the ESP is the MSP or MRSP, and the ESP or its' agent fails to provide the Meter data to the Company under the Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, the Company may, at its option, obtain the data or estimate the billing determinants.

(E) Where the Company is the MRSP, the Company will, at the request of the Customer or the ESP, reread or test the Customer's Meter within 10 working days after the request. The cost of each reread or test may be applied to the Customer or ESP when applicable.

(F) All energy sold to the Customer by MRSP will be measured by commercially acceptable measuring devices and under the terms and conditions of the Company's Schedule 10 - Terms and Conditions for Direct Access.

15.3 **Direct Access Deposits –** If the Customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount that reflects the portion of the Customer's service being provided by a Load Serving ESP. If the Load Serving ESP is providing ESP Consolidated Billing under the Company's Schedule 10 Section 7, the entire deposit will be credited to the Customer's account; or, if the Customer chooses to change from Direct Access to Standard

Offer service, the requested deposit amount may be increased by an amount under Section 3.3 which reflects that the Company is providing bundled electric service.

15.4 **Direct Access and Company Equipment**

(A) **Meters –** A Meter Service Provider (MSP) or its authorized agents may remove the Company's metering equipment under the Company's Schedule 10 Terms and Conditions for Direct Access. Meters not returned to the Company or returned damaged will result in charge(s) to the MSP of the replacement costs, plus an administration fee of 15%, less five year's depreciation.

(B) **Lock-rings –** The Company will lease lock-ring keys to MSP's or their agents who are authorized to remove Company Meters under the terms and conditions of the Company's Schedule 10 at a refundable charge of $70.00 plus applicable adjustments per key. The charge will not be refunded if a key is lost, stolen, or damaged. If the Company must replace 10% of the issued keys within any 12-month period because of loss by the MSP's agent, the Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock-ring keys must be returned to the Company within five working days if the MSP or its authorized agents are:

(1) No longer permitted to remove Company Meters under the conditions of the Company's Schedule 10;

(2) No longer authorized by the Arizona Corporation Commission to provide services; or

(3) The ESP Agreement has been terminated.

(C) **Site Meetings –** If the MSP, the Customer, or the Customer's agent requests a joint site meeting for removal of Company metering and associated equipment or lock ring, a base charge of $62.00 plus applicable adjustments per site will be assessed. The Company may assess an additional charge of $53.00 plus applicable adjustments per hour for joint site meetings that exceed 30 minutes. If the Company must temporarily replace the MSP's Meter or associated metering equipment during emergency situations or to restore power to a Customer, the above charges may apply.

DEFINITIONS

Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

Billing Date is the date the statement was created either in electronic or paper form as shown on the bill regardless of the postmark, mailing, or electronic transmittal date.

Billing Month means the period between any two regular readings of the utility's Meters at approximately 30-day intervals. [A.A.C. R14-2-201-(5)]

Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

Company Holidays (as referred to in section 2.4) are New Year's Day, Martin Luther King Jr. Day, President's Day Memorial Day, Juneteenth, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, the day after Thanksgiving, Christmas Eve, Christmas Day, and New Year's Eve.

Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]

Delinquent Bill means a bill in which current electric charges are considered past due (22 *calendar* days after the statement date).

Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(13)]

Distribution Lines means the utility lines operated at distribution voltages which are constructed along public roadways or other bona fide rights-of-way, including Easements on a Customer's property. [A.A.C. R-14-2-201-(14)]

Easement means the right to use land owned by another party by grant or as allowed by law. An easement gives the Company the right to have Company lines or facilities on property not owned by the Company. This allows the Company to build, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity and for other purposes. The owner may continue to use the land in the easement as provided by a written easement or by law.

Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer ("Landlord") and the Company, that provides continuous and uninterrupted service to the Landlord during intervals when a Landlord has no tenants. A Service Establishment Charge will not apply, and service will automatically be transferred into the Landlord's name. Landlord Automatic Transfer of Service Agreements are available to property owners that have established credit with the Company.

Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(27)]

Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(29)]

Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from the Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(30)]

Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(31)]

On-site means on a single Premises served by the Company's facilities.

Premises means all of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by alleys, canals, streets, railways, or other public rights-of-way.

Public Safety Power Shutoff (PSPS) means an event where the Company temporarily shuts off electric service within a specific area when extreme weather and other environmental conditions create an elevated wildfire risk such that proactive service interruption becomes necessary to help protect public health and safety and/or prevent damage to person(s) or property. The purpose of a PSPS event is to reduce the risk of wildfires caused by ignition from tree strikes, downed wires, equipment failures, or other events exacerbated by high-risk wildfire conditions in the environment (including, without limitation, relative high temperatures, low humidity, precipitation conditions, wind speeds and gusting, terrain, fuel complexity and moisture, or other acts of the elements that contribute to heightened wildfire risk in a given location).

Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C. R14-2-201(35)]

Working Day means a weekday (during normal business hours) that is not designated as a Company holiday.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

Statement of Charges		
Description	**Charge**	**Reference**
Residential Service Establishment Charge	$0.00	2
Nonresidential Service Establishment Charge	$0.00	2
After hours Charge – Residential Standard Metering	$0.00	2.2
After hours Charge – Residential Non-Standard Metering	$0.00	2.2
After hours Charge – Nonresidential	$164.00	2.2
Same Day Connect Charge	$0.00	2.3
Non-Standard Service Request Charge (per crew person, per hour)	$164.00	2.4
Dishonored Payment Fee	$15.00	6.4
Field Call Charge	$0.00	7.6
Overhead Reconnection Charge	$89.00	7.6
Underground Reconnection Charge	$135.00	7.6
Non-Standard Metering – Monthly Meter Reading	$5.00	8.4
Non-Standard Metering Set-up fee for customer with existing AMI meter	$50.00	8.4
Meter Reread	$14.00	8.7
Meter test in shop	$44.00	8.9
Meter test at site	$93.00	8.9
Trip Charge – Residential	$22.00	10.5
Trip Charge – Nonresidential	$26.00	10.5

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April 3, 2026

Chairman Nick Myers
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: Arizona Public Service Company (APS or Company)
Notice of Filing – APS Rate Case – Response to Chairman Nick Myers
Docket No. E-01345A-25-0105

Dear Chairman Nick Myers,

Thank you for your October 1, 2025 request for information regarding APS's direct testimony. Attached are responses to the questions outlined in your letter.

Please note, APS will continue to offer information throughout the rate case testimony, hearing, and briefing, and would be happy to supplement these responses as needed. APS appreciates the opportunity to address your request for information about the Company's Rate Case Application.

Sincerely,

/s/ Anne Carlton

Anne Carlton

AC/kr
Attachment

cc: Vice Chair Rachel Walden
Commissioner Lea Márquez Peterson
Commissioner Kevin Thompson
Commissioner René Lopez

1. Regarding the proposed Formula Rate Adjustment Mechanism (FRAM):
    a. In his direct testimony, Chris Bauer stated that investors and credit rating agencies would look favorably on formula rates.
        i. If the Commission approves formula rates for APS, should this impact the authorized return on equity (ROE)?

            ANSWER: No. Mr. Bauer makes this assertion based on the understanding that the Company's proposed FRAM, if adopted, will result in more timely cost recovery that reduces regulatory lag thereby improving the Company's ability to earn its allowed return. Examining the past decade, the company has not earned its authorized return in any year, and on average has under-earned its authorized ROE by approximately 1.0 percent and estimated to be as much as 3.25% in 2025. Addressing this regulatory lag, however, does not reduce the required return on equity itself, which is set based on a market analysis applied to a peer group of utilities, as provided in Mr. Coyne's testimony. As noted by Mr. Coyne:

            "As the program is new and its approval and implementation have yet to unfold, my preliminary view is that the FRAM is credit positive from an investor's standpoint and would bring APS's risk profile in closer alignment with the peer group companies that have a variety of rate mechanisms to address regulatory lag. Approval of the FRAM would not cause equity investors to reduce their return requirements for APS because the regulatory compact is intended to give utilities a reasonable opportunity to earn the authorized ROE, whether under formula rates or traditional base rate cases."

            As such, approval of the FRAM should not impact the authorized ROE determined in APS's pending rate case.

    b. The proposed FRAM includes an earnings test with a "dead band" of plus or minus 20 basis points of a utility's authorized ROE. In his direct testimony, Mr. Bauer stated that "If the earnings test for a given historical test year reflects an actual ROE within plus or minus 20 basis points of the authorized return, no adjustment to customer rates will be made." (p. 24). However, he adds that if the earned ROE fell within the dead band, a rate adjustment could still occur because rates are "subject to any changes related to the true-up." (p. 24).
        i. What are some changes related to the true-up that may cause rates to change even though the earned ROE fell within the dead band?

            ANSWER: APS's originally proposed FRAM provides for an annual challenge correction true up, as shown in Attachment 2 of the proposed FRAM schedules, which are included in Attachment JEH-

02DR to Jessica Hobbick's Direct Testimony. However, in the Company's Rebuttal Testimony, modifications to the FRAM are proposed to eliminate interim rate implementation and defer any FRAM rate adjustments until after the formal challenge period. If this approach is adopted, a true-up mechanism is no longer necessary, because any challenge adjustment or modification to the originally filed FRAM calculation will be captured in the current FRAM filing, as adopted by the Commission.

ii. Under the current ratemaking structure, utilities have the opportunity to earn the authorized ROE, not the guarantee. If the dead band guarantees the Company will earn a certain ROE, should the dead band be symmetrical (i.e. plus or minus 20 basis point) or should it be asymmetrical (e.g., plus 20 basis points and minus 30, 40, or 50 basis points or something greater)?

ANSWER: As is true under the current ratemaking structure, the FRAM provides APS the opportunity to earn its authorized ROE, not a guarantee. The annual FRAM adjustment allows the Company to set rates to a level that reflects the authorized ROE, but it does not true up a prior year deficiency. Because the FRAM is based on a historical test year, actual operating conditions, costs, economic conditions, and revenues (among other considerations) during the year when an updated FRAM rate takes effect will determine the level of the Company's actual earned return.

That said, a symmetrical dead band is appropriate. An asymmetric dead band creates structural bias by design, treating under- and over-earnings differently. It would require a larger earnings shortfall to adjust rates to recover prudently incurred costs, while smaller earnings excesses would trigger reductions. This one-sided approach effectively presumes that under-earning should be tolerated regardless of cost drivers or prudence. APS is not aware of any utility company with a formula rate that uses an asymmetric dead band.

Notwithstanding these positions, APS's Rebuttal Testimony proposes modifications to the FRAM that would expand the Company's formula deadband range to be more in line with interventor and Commission Staff positions. APS is now proposing a +/- 40 basis point deadband.

2. Regarding the deferral of costs associated with the cessation of coal-fired generation at Cholla Power Plant:
   a. Mr. Bauer states that "because of the significant increases in CCR-related costs - most of which will be incurred in large amounts annually over the next approximately five years - the deferral of these costs provides a mechanism to amortize these expenses over a longer period of time." (p. 34).
      i. Is deferral the only mechanism that would allow the amortization of these expenses over a longer period"

ANSWER: While other regulatory approaches may provide similar amortization of the expenses, the Company believes the deferral approach is the most well-established and defined methodology that would provide this benefit of amortizing these costs over a longer period. Depending on the eventual scope of these costs and expenses, which are estimates at this time and will only be known with certainty as the remediation and closure work progresses, securitization may be another option for recovering these costs over a longer period of time. Establishing a regulatory deferral mechanism in the pending rate case for these costs creates a foundation for the use of securitization in the future should that option become available (e.g., a sufficient amount of costs incurred that provides an appropriate base of liquidity for a successful securitization bond offering).

b. Would costs associated with the cessation of coal-fired generation at Cholla Power Plant be impacted if the plant was converted to natural gas or nuclear generation? If so, how?

ANSWER: No. The federal Coal Combustion Residuals regulations require APS to close the Cholla ash impoundments and address groundwater impacts from past coal operations. Those obligations, and their associated decommissioning costs, remain the same regardless of whether the plant is converted to another fuel source.

c. If closing the Cholla Power Plant early was a business decision and not legally required by the federal government, should customers pay for expenses related to the early closure of the plant?

ANSWER: The cessation of coal combustion at the Cholla Power Plant was not a business decision. The Regional Haze site-specific State Implementation Plan (SIP) for Cholla Power Plant (Cholla) mandated that APS cease burning coal no later than April 30, 2025, with the option to convert the plant for gas-firing operations after that point with no more than 20 percent annual capacity factor. This obligation is a federally enforceable requirement under the Clean Air Act.

d. If closing the plant earlier was more cost-effective for customers, what is the cost difference for customers between closing it earlier and continuing to operate the plant until its original retirement date?

ANSWER: As noted above, APS did not have discretion to continue burning coal at the Cholla Power Plant beyond the federally mandated cessation date (i.e., April 30, 2025). The Company's obligation to cease coal operations at Cholla was established through EPA-approved Clean Air Act requirements, including the source specific Regional Haze SIP revision approved by the U.S. Environmental Protection Agency in 2017, which made the coal cessation obligations at Cholla federally enforceable.

Contemporaneously with the development of the SIP finalized in 2017, the requirement to cease burning coal at Cholla by April of 2025 was

evaluated by APS in its 2014 Integrated Resource Plan. Through an evaluation of replacement resource options, compliance with the Regional Haze SIP obligations and reliance on alternative resources in 2025 was found to create material customer cost savings.

As part of its long-term resource planning, and consistent with the EPA-approved SIP revision, the Company is evaluating conversion of the Cholla facility to natural gas in its 2026 Integrated Resource Plan. Gas conversion is currently authorized under the governing Regional Haze SIP and is being evaluated to assess whether it is consistent with meeting customer needs with reliable, lower cost resources.

3. Regarding proposed changes to the treatment of investment tax credits related to Arizona Sun BESS:
   a. Mr. Bauer states that accelerating the amortization and the ITC benefits of its Arizona Sun BESS "will offset the cost of electricity for current customers in this rate case.... reducing the current revenue requirement by $19.8 million." (p. 35)
      i. What are the net costs/savings to customers by accelerating the amortization over the useful life of the battery system?

         ANSWER: If the Company's proposal to accelerate amortization over a 3-year period and include such amortization as a reduction to the cost of service was not adopted (either by the Commission or the U.S. Internal Revenue Service), and instead the current method of sharing these BESS ITC benefits over the book useful life was retained, the revenue requirement would be $19.8M higher in this rate case.

      ii. Do the accelerated ITC tax benefits offset the higher cost to customers of a shorter amortization period?

         ANSWER: Yes. APS recommended an accelerated three-year amortization period to create a cumulative revenue-requirement reduction for customers of approximately $16M (as compared to the current methodology).

4. Regarding the pro forma adjustment to annualize Four Corners Coal Reclamation Costs:
   a. In her direct testimony, Elizabeth Blankenship states that "[d]ue to the long-term nature of these costs, APS escalated the cost estimates for Four Corners through June 2031, which is aligned with the terms of the coal supply agreement. In an effort to reduce customer bill impacts, the Company has extended the amortization period through June 2038." (p. 30).
      i. How would the Four Corners Coal Reclamation Costs and amortization period be impacted if APS sold its Four Corners assets to the Navajo Nation, as Jacob Tetlow mentions in his direct testimony (p. l 8)?

         ANSWER: At this time, APS remains a party to a Coal Supply Agreement for Four Corners that requires APS to pay coal

reclamation costs through the end of the agreement term in 2031. Otherwise, APS remains engaged in discussions with NTEC and the Navajo Nation regarding the potential for future operations of Four Corners beyond 2031. As such, it remains unclear at this time whether or how coal reclamation payment obligations under the current Coal Supply Agreement would be impacted by any other transactions related to continued plant operations beyond 2031.

ii. Would Four Corners Coal Reclamation Costs be impacted if the plant was converted to natural gas or nuclear generation after the coal plant is retired in 2031? If so, how?

ANSWER: The Company expects that, after 2031, there would be no further coal-reclamation expenses to address if the plant were converted to operate using another, non-coal fuel source (e.g., natural gas).

iii. If closing Four Corners early is a business decision and not legally required by the federal government, should customers pay for expenses related to the early closure of the plant?

ANSWER: Due to rapidly expanding load growth, APS is exploring options for continued operation of the plant beyond 2031 and is not considering exiting from Four Corners early at this time.

iv. If closing Four Corners early is more cost-effective for customers, what is the cost difference for customers between closing it in 2031 and continuing to operate the plant until 2038?

ANSWER: Due to rapidly expanding load growth, APS is exploring options for continued operation of the plant beyond 2031 and is not considering exiting from Four Corners early at this time.

5. Regarding pro forma adjustment to include the wildfire mitigation O&M expense accumulation in rate base:
   a. Ms. Blankenship states that the requested "rate base pro forma adjustment includes incremental wildfire mitigation O&M costs from January to March 2025 and forecasted wildfire mitigation operation and maintenance costs from April 2025 through October 1, 2026." (p. 41).
      i. O&M costs are not typically included in rate base, why should wildfire mitigation O&M expenses be treated differently?

ANSWER: The Company is requesting that these incurred costs be recovered in rate base because APS was required to fund these costs without sufficient recovery through rates. APS's wildfire mitigation O&M expenses have increased significantly since the last rate case due to heightened wildfire risk, expanded mitigation activities, and substantial increases in wildfire-related insurance premiums, all of which are driven by factors outside APS's control. The sustained and extraordinary cost increases would be unrecoverable without a regulatory deferral mechanism. Creating a regulatory asset for incremental wildfire mitigation O&M since

the prior rate case, to be amortized over a period of five years, ensures timely recovery of prudently incurred costs necessary to maintain safe and reliable service and avoids undermining APS's ability to fund essential wildfire risk-reduction efforts.

Between 2021 and the expected rate effective date in the pending APS rate case, APS expects to incur over $104 million in wildfire mitigation O&M expenses that are not recovered in current rates, and will not be recovered. Of this total, APS is seeking regulatory asset treatment for $27.9 million. Putting this regulatory asset in rate base is appropriate recognition for APS needing to fund these necessary mitigation activities without support from rates. Over this period, APS needed to use limited debt and equity capital resources to fund these critical O&M costs. The proposed regulatory asset treatment would allow APS a method to partially recover a component of these under-recovered costs, including providing a return on APS's capital that was used to fund these O&M costs.

b. What are the wildfire mitigation O&M expenses for 2021, 2022, 2023, 2024, and 2025? Should the Test Year be normalized using the O&M expenses over these five years?

ANSWER: Please see the table below for an updated summary of the Company's wildfire mitigation O&M expenses for the requested years.

Wildfire O&M Costs by Year				
2021	**2022**	**2023**	**2024**	**2025**
$18,197,787	$17,603,313	$18,420,455	$23,624,949	$36,874,870

The Test Year should not be normalized using a multi-year historical average as the result would understate the test year amount and would not be representative of expected costs. Instead, as discussed in APS's Direct Testimony, a forward forecasted normalization would be more appropriate as it would capture increasing costs expected into the future. Wildfire mitigation O&M has experienced a steep and sustained upward trajectory driven by increased risk, expanded mitigation activities, and materially higher insurance costs. Including historical periods when these costs were significantly lower would dilute the current cost level and fail to reflect the new normal of ongoing wildfire mitigation spending. As a result, a multi-year historical average would not capture known and measurable changes and would not reasonably represent future cost expectations.

6. Regarding Cholla Unit 2 cost of removal:
   a. Ms. Blankenship states that an updated study forecasts removal costs for Unit 2 through June 2033 that results in an annual removal cost estimate of $15,699,083 (p. 46). Please explain the removal costs included in this annual estimate.

ANSWER: Cost of removal refers to the demolishing and/or dismantling of the asset and primarily consists of labor and other costs associated with transportation and handling of the dismantled asset. Costs also include waste disposal and the Unit 2 share of sitewide environmental remediation to ensure compliance with Environment Protection Agency requirements, in particular those related to CCR. The figure referenced in Elizabeth Blankenship's Direct Testimony is reflective of the Unit 2 share of costs based on plantwide decommissioning cost estimates.

b. How much has already been collected from customers for these annual removal costs? How much remains to be collected from customers?

ANSWER: As of December 31, 2025, APS has collected $18.93 million from customers for removal costs as to Cholla Unit 2 and $106.67 million remains to be collected.

c. Would costs associated with Cholla Unit 2 cost of removal be impacted if the plant was converted to natural gas or nuclear generation? If so, how?

ANSWER: At this time, APS is only evaluating Units 1 and 3 for possible gas repowering, and has not made any decision to convert the Cholla plant site to accommodate an alternate fuel source, including natural gas or nuclear generation, and no such conversion is assumed or reflected in the Cholla Unit 2 cost of removal estimates presented in this case. Accordingly, APS cannot and does not speculate as to potential impacts to Cholla Unit 2 cost of removal associated with a hypothetical conversion of the site to an alternate fuel source.

7. Regarding Formula Rate Adjustment Mechanism (FRAM):
   a. Jessica Hobbick states that under the proposed mechanism, the annual compliance filing (i.e., Annual Update) would include "12-months of projected plant." (p. 13).
      i. Please discuss why projected plant should or should not be included in the Annual Update.

ANSWER: In accordance with the Commission's Policy Statement Regarding Formula Rates, APS's original FRAM proposal from its rate case Application was modeled based on FERC Formula rate protocols, which include the use of projected plant in addition to the use of a historical test year. The inclusion of projected plant in the FRAM calculation ensures that the timing of cost recovery aligns more closely with the timing of those assets providing benefit to customers and reduce regulatory lag. The Company begins investing in facilities sometimes years before they are placed in service. If projected plant is included in the FRAM, there could still be more than 18 months between the date on which an asset is placed in service and the date those costs are included in new rates. That lag is exacerbated if the FRAM is approved without projected plant.

Nonetheless, in an effort to align APS's proposal closer to the positions of intervenors and Commission Staff, the Company is

accepting Staff's recommendation regarding the number of months of post-test year plant to be used in each FRAM filing, modifying the proposed FRAM POA post-test year plant timeline from 12 months to 6 months. Considering this modification, all assets requested for recovery through the FRAM will be in service and benefiting customers prior to the filing of each annual update. As such, none of the plant investments reflected in APS's proposed FRAM updates will represent "projected" or planned investments that have not yet gone into service.

b. Under the proposed plan, generation costs being recovered in the SRB-which included a 100-basis point discount on the weighted average cost of capital-will be transferred into the FRAM during the annual rate reset (p. 13).
   i. Should new generation costs (non-SRB) included in an Annual Update include a similar discount?

      ANSWER: No. The SRB 100-basis points discount was provided to specifically apply to the singular large generation projects requested for recovery through each SRB filing. In APS's original FRAM proposal as part of its rate case Application, recovery of these costs would subsequently transfer into the FRAM or into rate base through a general rate case, generally within a year. In APS's Rebuttal Testimony, however, the Company is now proposing that, if the FRAM is adopted, the SRB mechanism should be eliminated. In an effort to bring APS in closer alignment with intervenors and Commission Staff, the Company is willing to eliminate the SRB and rely solely on the FRAM or general rate cases for cost recovery associated with all generation investments.

c. Under the proposed plan, "[r]esidential customers, and most general service customers will experience adjustments limited to 0.85 to 1.15 times the annual average adjustment, while customers on Extra Large General Service Rate Schedule E-34, E-35, and XHLF will receive the rate adjustment needed to ensure they do not achieve less than the cost to serve the class." (p. 15).
   i. Will costs of service be updated with each Annual Update? If not, will the cost of service established in the last general rate case be used?

      ANSWER: Yes. A cost of service study will be prepared and updated with each formula rate annual filing and will be used to allocate each formula rate update.

   ii. Are changes in the number of customers in each class (especially residential customer growth) accounted for with each Annual Update?

      ANSWER: Yes. The number of customers is a required input and will be updated annually to accurately allocate customer-driven costs.

iii. Are the adjustment limits of 0.85 to 1.15 times the annual average adjustment included in the FRAM POA?

ANSWER: Yes, these adjustment limits apply to Residential and Small-to-Medium General Service classes. The limits are reflected in Attachment 3.3 that accompanies the FRAM POA.

iv. Should interested parties and/or interveners be able to challenge these adjustments, even if they fall within the 0.85 to 1.15 limit? If so, should these adjustments be established in a general rate case and remain the same with each Annual Update, or should they be modified with each Annual Update?

ANSWER: Interested Parties may challenge any aspect of the annual formula rate adjustment and calculation provided the challenge is limited to the issues detailed in Section 6 of the proposed FRAM Plan of Administration. This would include challenges to the prudency of any plant investment or expense occurring within a FRAM evaluation period (historical test year plus six-months of post-test year plant). APS's Rebuttal Testimony proposes changes to the FRAM POA reinforcing this process.

The 0.85 to 1.15 limits proposed in the FRAM calculation apply only to revenue allocation based on the annual cost of service study and will be established based on the Commission's decision regarding the FRAM POA and associated schedules. In the event that these limits are approved by the Commission, the FRAM schedules and limits therein will remain in place unless adjusted by a subsequent Commission decision.

v. Historically, commercial customers have paid above their cost of service, some considerably so. If customers on Extra Large General Service Rate Schedule E-34, E-35, and XHLF are paying at their cost of service, does that mean that smaller commercial customers will be paying above their actual cost of service while the largest commercial customers will not?

ANSWER: APS's FRAM proposal is intended to ensure that all extra-large General Service customers pay their cost of service. Commercial customer classes have historically varied by class and by year in regards to their payments towards their cost of service. The FRAM is designed to continually bring all other rate classes' rates closer towards parity with their cost to serve, and as future updates are implemented, rates for each rate class will continue to trend towards parity. Residential customer groups have historically paid rates below their cost to serve, and as a function of the mathematical calculation within the cost of service, other rate classes must pay above their cost of service in order to reconcile to the full revenue requirement among the combined rate classes.

8. Regarding retaining adjustors:
    a. Ms. Hobbick states that APS proposes to retain the following adjustors: TEAM, TCA, SRB, PSA, DSMAC, and REAC (p. 16-17).
        i. If these adjustors are currently updated on an annual basis, why not eliminate these adjustors and include them as part of the annual formula rate update?

            ANSWER: As provided in APS's original FRAM proposal in the rate case Application, maintaining certain adjustor mechanisms alongside the proposed FRAM is necessary to preserve the transparency that they provide. This is consistent with Decision No. 79293, which rejected the transfer of various costs collected in adjustment mechanisms into base rates.

            Please note, in addition to the elimination of the LFCR, the Company is accepting Staff's recommendation to eliminate the SRB and TEAM mechanisms if the FRAM is approved and maintains a 120-day schedule. This proposal brings APS's proposed FRAM closer into alignment with the positions offered by intervenors and Commission Staff, in particular Staff witness Ralph Smith.

        ii. If these adjustors are retained, would it be possible to update these adjustors each year at the same time the annual formula rate adjustment takes effect to avoid the possibility of multiple increases throughout each year?

            ANSWER: Updating all of the Company's adjustors simultaneously would not be effective in promoting a fulsome and comprehensive review by Commission staff and other stakeholders of each of the Company's adjustor mechanisms. Each adjustor mechanism requires time to analyze, prepare, review, and file with the Commission. In addition, staggering rate adjustor changes is a common industry practice that promotes gradualism and maintains a clear distinction between adjustors and cost types in the event of cost increases or decreases.

9. Regarding modifications to the SRB POA:
    a. Ms. Hobbick states that APS seeks to modify the SRB POA to specify that investments recovered within the SRB would be transferred into base rates in the annual formula rate reset following an approved SRB application and rate implementation (p. 32).
        i. Would SRB investments transferred into base rates retain their 100-basis point discount applied to the weighted average cost of capital associated with those investments?

            ANSWER: No. APS is now proposing to eliminate the SRB (along with the TEAM and LFCR adjustor mechanisms) as part of a package of modifications to the FRAM in the Company's Rebuttal Testimony. As such, this 100-basis point discount mechanism would no longer apply.

b. APS further proposes to remove the earnings test in Section 6 of the SRB POA and replace it with the annual earnings test within the proposed formula rate plan (p. 32).
   i. How are these earnings tests similar or different? Is there value in keeping the current earnings test for SRB investments?

      ANSWER: As to APS's current FRAM proposal presented in Rebuttal Testimony, the Company is proposing to eliminate the SRB as part of a package of modifications. As a result, there will be no need for a separate earnings test for generation investments that might have otherwise been subject to cost recovery through the SRB. The annual FRAM update will calculate the Company's earned return and will credit back to customers any earnings over the authorized ROE inclusive of the deadband.

c. The SRB POA states that APS shall not defer for future recovery in a subsequent SRB proceeding any amount that exceeds the Earnings Test Threshold and shall not be permitted to increase the SRB surcharge to be applied for in excess of Earnings Threshold for the following year.
   i. Does the formula rate's earnings test include this customer protection?

      ANSWER: No. The entire FRAM calculation is an earnings test threshold, which allows for adjustments to rates to ensure that the Company is not overearning. That said, the annual FRAM adjustments will not include recovery of any prior year revenue deficiency as part of a subsequent period.

10. Regarding eliminating the AutoPay Credit:
    a. Ms. Hobbick states that APS proposes to eliminate the AutoPay credit (i.e. $0.48) (p. 33).
       i. When and why was this credit instituted and why should it now be eliminated?

          ANSWER: The $0.48 monthly AutoPay credit was implemented in 2007, pursuant to Decision No. 69663, issued on June 28, 2007, in APS's 2005 rate case. In 2007, electronic payment options were limited and not yet the standard way to pay bills. Today, these payments are widely adopted across the utility industry and beyond.

          APS is proposing to remove the AutoPay credit because it is no longer needed to drive enrollment in the program. When the credit was originally adopted in 2007, many customers still paid by paper check and electronic payment options were limited. The credit was intended to encourage customers to move from higher cost paper payments to lower cost electronic payments. Since then, customers have access to a wide range of electronic payment options beyond just AutoPay, including online payments, mobile app transactions, and other electronic channels that provide convenient, low-cost alternatives to traditional paper

methods. Today, over 90% of payments now come in through electronic channels, with paper checks at less than 7%.

ii. Does AutoPay provide benefits or savings to APS? If so, should customers continue to be incentivized with a credit to enroll in AutoPay?

ANSWER: AutoPay is one of APS's lowest cost payment channels. However, there are various electronic payment channels that are similar in cost that customers transition to and from. As a result, the monetary savings that were initially experienced when customers transitioned from a higher cost payment channel no longer exists. A customer who pays each month on aps.com and then enrolls in AutoPay does not result in transaction cost savings. While there certainly are operational benefits from AutoPay, like reliable low-cost payment processing and efficiency, and the convenience it offers customers in not needing to take action to pay each month as the payment is automatic, the incremental savings to APS are minimal and no longer tied to the historical $0.48. As mentioned, electronic to electronic transitions do not reduce processing costs the same way transitions from paper checks to electronic do. As such, the incentive is no longer necessary or appropriate. AutoPay is now a mature, widely adopted payment channel, as are other low cost electronic payment channels, and participation is driven by convenience rather than financial incentives.

11. Regarding a change to Service Schedule 3:
    a. Ms. Hobbick states that APS proposes to add language to Service Schedule 3 to ensure Electrical and/or Irrigation Districts do not encroach on APS's CC&N (p. 33-34).
        i. Why is this change needed? Has this been a problem?

ANSWER: APS has recently observed that Electrical Districts operating within APS's CC&N territory are now seeking to provide electric service to large and high load factor customers, including data centers. APS's original Service Schedule 3 proposal was intended to address the potential impacts of this trend. Nonetheless, based on feedback from Commission Staff, APS has decided to withdraw this proposal in its Rebuttal Testimony.

12. Regarding the Court Resolution Surcharge (CRS) pro forma adjustment:
    a. Ms. Hobbick states that APS proposes to transfer the portion of the CRS recovering the prospective Four Corners Power Plant SCR equipment into base rates, leaving just the amortization of the historical ROE and SCR amounts remaining in the adjustor until fully recovered (p. 36).
        i. Why is this transfer needed? What are the benefits?

ANSWER: APS is proposing to transfer prospective Four Corners SCR equipment costs into base rates, as these costs are part of APS's ongoing revenue requirement, while historical balances will

continue being amortized through the CRS adjustment mechanism as it was designed so this mechanism may sunset upon full amortization of the historical balance, which APS anticipates will occur in December 2026. This transfer is revenue neutral, because the CRS rate is being reduced commensurate with an increase to base rates, and does not result in increased rates for customers.

13. Regarding the base revenue annualization pro forma adjustment:
    a. Ms. Hobbick states that APS is proposing to annualize the effects of the revenue requirement approved in Decision No. 79293 across all 12 months of the Test Year, resulting in a decrease to pre-tax operating income of $98.96 million (p. 36).
        i. Why is this pro forma adjustment needed? What are the benefits?

ANSWER: The Base Revenue Annualization Pro Forma is needed when new rates from a prior rate case become effective during the Test Year for the current rate case under consideration. The adjustment in this rate case annualizes the effects of the revenue requirement approved in the most recent rate case (Decision No. 79293), giving customers the benefit of increased revenue from those rates across all 12 months of the Test Year. The purpose of the pro forma adjustment is to rebill/annualize all the billing determinants at current rates for all Residential and General Service customers. This allows for a more accurate picture of what the revenue deficiency is, as well as the needed increase. In this rate case, the pro forma adjustment increased Test Year revenues and therefore decreased the revenue deficiency. Had the annualization not been done, and actual revenues for the year used instead, the revenues from January 1 through March 7th would have been based on prior rates and not accurately represent a full year of revenue under current rates. Although the adjustment was performed correctly within schedules, the language referenced in Ms. Hobbick's Direct Testimony should have described this pro forma adjustment as an increase to pre-tax operating income rather than a decrease. Please consult SFR Schedule C-2, page 7, column 20, demonstrating that this pro forma resulted in an increase to Test Year operating income, which is included within APS's Rebuttal Testimony.

14. Regarding pro forma adjustment to annualize customer levels:
    a. Ms. Hobbick states that APS is proposing to annualize customer levels (p. 36-37).
        i. Why is this pro forma adjustment needed? What are the benefits?

ANSWER: The customer annualization revenue pro forma adjusts Test Year revenues to reflect customer growth or decline during the Test Year. This adjustment is needed to ensure that the final approved level of revenue generally reflects the customer level that occurred at the end of the Test Year, which typically is a better indication of the expected level going forward compared with the average customer level that occurred throughout the Test Year.

15. Regarding normalizing weather conditions:
    a. Ms. Hobbick states that APS is proposing to adjust Test Year revenue "for normal weather (over a ten-year historical period) to demonstrate that the final level of revenue approved reflects retail energy consumption associated with average or typical temperature and humidity patterns." (p. 37).
        i. If the last 3-5 years have reflected record-breaking heat and established a "new normal," why not use this shorter historical period rather than a ten year period?

            ANSWER: The last three to five years have reflected record-breaking heat, which has increased summer temperatures in the ten-year average to higher levels than seen historically. However, there have been variances to weather within the past three-to-five years and reflecting a 10-year average is an appropriate balance. For instance, 2023 and 2024 had record-breaking heat, but 2022 and 2025 were closer to the historical average.

            Using fewer years in the historical period for normal weather means that each year carries more weight in the average, which adds volatility over time as the definition of normal weather is updated each year. Using fewer years, such as three years, would make the historical weather average especially sensitive to extreme or mild summers, which could create large fluctuations in reporting and forecasts from year to year. The Company found that using a 10-year average brings the best balance between stability in processes and reporting, and stability over time in load and revenue forecasts.

16. Regarding Plan of Administration for FRAM (Attachment JEH-02DR)
    a. Under the POA, the "Authorized Rate of Return" means "The ROE and capital structure authorized in the most recent rate case, adjusted for fair value increment, with an updated cost of debt for the Historical Test Year ..." (p. 2)
        i. What does "adjusted for fair value increment" mean in this context where the ROE and capital structure are not changing between rate cases?

            ANSWER: Consistent with the LFCR Earnings Test, the dollar value of FVI will be converted into basis points of adjusted ROE based on what is approved in the previous general rate case and will not change between rate cases. This reflects the authorized level of return approved by the Commission.

        ii. Should the cost of debt be updated each year if the ROE remains the same? How would updating the cost of debt each year impact the Weighted Average Cost of Capital? Why should ROE and cost of debt be treated differently?

            ANSWER: Unlike the authorized return on equity, cost of debt is a known and measurable factor, as it is based on actual results and

is a function of market forces. By contrast, in determining a recommended return on equity, the parties hire expert witnesses to evaluate a proxy group of peers and perform multiple modeling assessments (among other time consuming activities), which would be unreasonable to reperform annually. Allowing the cost of debt to be updated based on actual historical test year data keeps the cost of debt in the FRAM calculation aligned with the actual cost of debt experienced by APS based on market forces. When interest cost savings are experienced by APS, annual updates to the cost of debt will allow these lower interest costs to be passed to customers in a more timely manner.

The cost of debt is a component of the overall Weighted Average Cost of Capital and is multiplied by the debt portion of the capital structure, and ROE is multiplied by the equity portion of the capital structure. This calculation is shown in Schedule D of the proposed FRAM Schedules, included in Attachment JEH-02DR to Jessica Hobbick's Direct Testimony.

b. How would the proposed Revenue Requirement Index (p. 2) be used in each Annual Update? Is this index static and part of the FRAM POA or will it be updated and included with each Annual Update filing?

ANSWER: The Revenue Requirement Index measures the percentage change in revenue requirement by comparing test year revenues by class with updated cost of service revenues by class. This index is used to yield a revenue requirement percentage change for each cost of service class, which is then used to apply class-level limits of 0.85 to 1.15 for revenue allocation as provided in the FRAM POA. The Revenue Requirement Index is updated based on test year revenues and the annual cost of service study.

c. Could the Company provide notice of the Interested Party Meeting (p. 5) in the docket of its last rate case in addition to being posted on its website and emailed to parties in the last rate case?

ANSWER: Yes.

d. Regarding informal challenges (p. 6), could the Company provide redacted copies of Informal Challenges and responses that contain confidential or proprietary information of APS or third parties, in addition to providing unredacted copies under a confidentiality or protective agreement?

ANSWER: Yes. In addition, the Company intends to treat confidential Informal Challenge information similar to how it is treated in a rate case for confidential discovery responses, by providing a non-confidential public narrative that directs to a confidential attachment.

e. Regarding formal challenges, the POA states that a party may not pursue a Formal Challenge on an issue if the party did not submit an Informal Challenge on such issue prior to August 12 (p. 6).

i. However, interested parties also have until August 12 to serve data requests as part of the Information Exchange Period and APS has until August 26 to respond (p. 4, 8). There does not seem to be time for an interested party to receive and evaluate APS's response before having to decide whether to submit an Informal Challenge. In effect, the proposed timeline will likely require interested parties to file an Informal Challenge alongside their data request to preserve their ability to file a Formal Challenge on the issue. But, interested parties must specify "the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support the challenge." (p. 6). An interested party may not be in the position to provide this required information for an Informal Challenge without first receiving and evaluating APS's response to their data request.

1. Could the timeline be amended to provide time for parties to receive and evaluate APS's data request response?

   ANSWER: The Company believes the proposed timeline offers sufficient opportunity for Interested Parties to issue data requests and challenges if deemed necessary. Informal challenges may be submitted immediately upon publication of the annual update, and if informal challenges cannot be resolved by the proposed deadline, the formal challenge period is available. However, in an effort to achieve greater alignment with Commission Staff and intervenors, the Company is modifying the proposed FRAM POA to extend the Informal Challenge submission deadline from August 12 to August 19 to address stakeholder concerns regarding the timeline. In addition, the Company is also allowing interested parties who have not issued an informal challenge to maintain the right to issue a formal challenge, as a good-faith effort to provide even greater opportunity for interested parties to challenge items in the FRAM if deemed necessary.

2. Should an interested party be able to pursue a Formal Challenge after evaluating another party's data request and APS's response?

   ANSWER: Yes. In an effort to achieve greater alignment with Commission Staff and intervenors, the Company is modifying the proposed FRAM POA to allow interested parties who have not issued an informal challenge to maintain the right to issue a formal challenge.

17. Regarding PSA base rate for net margins from emission allowance sales:
    a. Jamie Moe states that APS does not propose to change the PSA base rate of 0.000001 cents/kWh for net margins from emission allowance sales (p. 6).
       i. Could this be explained in more detail?

ANSWER: Net margins on emission allowances included in APS's PSA POA are related to SO2 allowances under the EPA's Clean Air Act Acid Rain Program only. This treatment was authorized in Decision No. 71448. APS did not sell any S02 emissions allowances during the period 2021 through 2025 and does not expect to have any emission allowance sales going forward.

18. Regarding ROE:
    a. James Coyne states that his analysis supports an authorized ROE of 10.70 percent for APS (p. 4).
        i. If formula rates are adopted with a guaranteed return within the dead band, should this impact the authorized ROE?

        ANSWER: Please see the Company's response to 1.a.i above. Because the FRAM is based on a historical test year, there is no guarantee whatsoever that APS can earn its authorized ROE in a given year. Earnings in a given year relative to the authorized ROE will always be based on actual operating conditions, costs, and revenues (among other factors).

    b. Mr. Coyne states that "The relative magnitude of the Company's capital expenditure plan suggests that APS has an above average risk profile as compared to the proxy group, recognizing that a portion of that risk is offset by the approval of the SRB." (p. 42).
        i. In addition to the SRB offset, does the Company's risk profile change compared to the proxy group if formula rates are adopted in this rate case?

        ANSWER: Formula rates are credit supportive and, if approved, would make APS more like the operating companies held by the proxy group, many of which have formula rates or operate under multiyear rate plans that reduce regulatory lag (which is shown in Attachment JMC-10DR to Mr. Coyne's Direct Testimony). The FRAM is designed to address significant regulatory lag in Arizona in part due to the use of a historical test year for ratemaking purposes. APS has not been able to earn its authorized ROE for the past decade as discussed in the response to 1.a.i above. The FRAM will provide APS a better opportunity to earn its authorized ROE under the regulatory compact. In the absence of the proposed FRAM, a higher ROE could have been justified, but Mr. Coyne made no upward adjustment to his ROE recommendation to account for APS's greater business and regulatory risk relative to the proxy group.

        The FRAM does not mitigate other business risks for APS, including nuclear generation ownership, wildfire risk, elevated capital spending compared to prior years and the associated execution risk, and customer concentration and data center growth. Please see Section VII of Mr. Coyne's Direct Testimony (pages 37-50) for a discussion of these risks for APS relative to the proxy group.

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April 3, 2026

Chairman Nick Myers
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

RE: Arizona Public Service Company (APS or Company)
Notice of Filing – APS Rate Case – Response to Chairman Nick Myers
Docket No. E-01345A-25-0105

Dear Chairman Nick Myers,

Thank you for your December 18, 2025 request for information regarding the Company's treatment of prospective high load factor customers. Attached are responses to the questions outlined in your letter. This topic is discussed further in the Rebuttal Testimonies of Jessica Hobbick, Jacob Tetlow, and Chris Bauer.

Please note, APS will continue to offer information throughout the rate case testimony and hearing and would be happy to supplement these responses as needed. APS appreciates the opportunity to address your questions about this important topic.

Sincerely,

/s/ Anne Carlton

Anne Carlton

AC/kr
Attachment

cc: Vice Chair Rachel Walden
Commissioner Lea Márquez Peterson
Commissioner Kevin Thompson
Commissioner René Lopez

1. Does APS require interconnection queue deposits from prospective high load factor customers, including data centers?

   ANSWER: Today, there is no fee assessed simply to enter the queue. APS does require a $25,000 fee from prospective high load factor customers prior to adding the customer to the Large Customer Project Queue. The fee covers the cost of an initial engineering study (Feasibility Study) as part of the study to determine the basis for which service may be provided under Schedule 3, section 19. This is not a refundable deposit.

2. If APS does require a deposit, what is the purpose of the deposit? How is the amount of the deposit determined? Are deposit amounts impacted by the prospective customer's load in MW?

   ANSWER: The $25,000 engineering study fee covers labor and materials used to conduct a Feasibility Study based on the project details. The fee is not impacted by the size of the prospective customer load.

3. Does the deposit help distinguish legitimate from "place holder" requests?

   ANSWER: The fee is not intended to distinguish speculative requests from real requests. Rather, the willingness of a customer to agree to the requirements imposed in the Load Commitment Agreement (LCA) distinguishes between speculative and real requests. The LCA specifies the customer’s load ramp and commits the customer to paying the costs associated with the minimum demand and energy usage identified in its project request before their load is included in the Company’s long-range forecast (80% demand, 80% energy). Among other terms designed to protect existing APS customers, the LCA also requires collateral to secure LCA obligations, long-term commitments, and early termination payments.

4. If the current deposit does not help distinguish requests, could deposit requirements be modified and/or withdrawal penalties added to help with the accuracy of load growth forecasts?

   ANSWER: Based on APS’s experience with regard to its Federal Energy Regulatory Commission (FERC) Large Generator Interconnection Process (LGIP), the Company does not believe deposits are an effective deterrent for speculative requests. Requiring customers to agree to the terms in the LCA process accomplishes this objective. As noted in response to question 3 above, new large, high-load factor customers do not enter the load forecast until they have signed an LCA.

REBUTTAL TESTIMONY OF JAMIE R. MOE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-25-0105

April 3, 2026

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Summary of Updated 2024 Test Year Adjusted COSS ..... Attachment JRM-03RB
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REBUTTAL TESTIMONY OF JAMIE R. MOE
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-25-0105)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Jamie R. Moe. My business address is 400 N. 5th Street, Phoenix, Arizona 85004. I am the Manager of Regulatory Affairs for Arizona Public Service Company (APS or Company). I have management responsibility for all aspects relating to rate strategy and specific rates and prices.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. I sponsor the ACC jurisdictional allocation of various updates to the Company's Standard Filing Requirement Schedules (SFR), an update to the Fair Value Rate Base (FVRB), Fair Value Increment (FVI), and Fair Value Rate of Return (FVROR). My Rebuttal Testimony also responds to various statements and recommendations made by Utilities Division Staff (Staff) of the Arizona Corporation Commission (Commission or ACC) and various intervenors in their direct testimony concerning the following:

- APS's Cost of Service Study (COSS);
- Growth-based allocation;
- Proposed growth-related changes to allocators as well as the Base Fuel rate and Power Supply Adjustor (PSA); and
- Site Load COSS and the Solar Credit.

While I may not address every detail related to the Staff's and intervenors' recommendations, it should not be interpreted that I agree with each position unless specifically stated within my testimony.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In my Rebuttal Testimony I address several aspects of intervenor recommendations on the COSS. I respond to various intervenor positions regarding the production demand and distribution cost allocation methodologies, as well as the Company's proposed growth-related cost allocations. I provide clarification regarding APS's proposal for calculating and direct assigning growth-related fuel and purchase power costs within the annual PSA filings. Finally, I discuss and respond to concerns related to the use of residential distributed generation (DG) customers' site load in the COSS and the calculation of the Solar Credit.

III. STANDARD FILING REQUIREMENTS

Q. ARE YOU SPONSORING ANY UPDATES TO SFRS?

A. Yes. I am sponsoring an update to SFRs A-1, B-1, B-2, C-1 and C-2, specifically related to the ACC jurisdictional allocation.

Q. PLEASE DESCRIBE THE UPDATES TO THESE SFRS.

A. APS has made several updates to its SFRs. Some updates were identified through the discovery process, and others were anticipated and customary changes, such as the update to post-Test Year plant (PTYP) to reflect 12 months of actual plant balances as described in the Rebuttal Testimonies of APS witnesses Elizabeth A. Blankenship and Jacob Tetlow. In addition, APS is incorporating some recommendations from Staff and intervenors. These rate base and income statement adjustments result in changes to APS's FVRB and the FVI to rate base.

IV. FAIR VALUE RATE OF RETURN

Q. DID APS UPDATE ITS FVRB AND RATE OF RETURN FOR THE ADJUSTED TEST YEAR?

A. Yes. APS has increased its FVRB by $548.6 million. Thus, the Company's proposed FVRB is now $22.2 billion. The net result of all rebuttal rate base changes, plus a downward adjustment of 10 basis points to the return on the FVRB Increment as discussed by APS witnesses Chris R. Bauer and James M. Coyne in their Rebuttal Testimonies, is a revised FVROR of 4.86%.

Q. DID APS USE THE SAME METHODOLOGY TO COMPUTE FVRB AND FVI AS IN THE APPLICATION?

A. Yes. I have revised the inputs but have used the same method of computation. Please see Rebuttal SFR Schedule A-1, line 9 (Attachment JRM-01RB) and Attachment JRM-02RB.

V. CORRECTIONS TO DIRECT TESTIMONY OR COSS

Q. DO YOU HAVE ANY CORRECTIONS TO YOUR TESTIMONY OR THE COSS?

A. Yes, there are a few corrections made in the COSS. I will note them below and provide detail on each. A summary of the updated COSS is included as Attachment JRM-03RB.

First, the COSS in the Application inadvertently used incorrect values to represent the Network Integrated Transmission Services (NITS) and Ancillary Services revenues for the following rate classes: E-34, E-35, XHLF, E-34 AG-X, and E-35 AG-X. The NITS and Ancillary Services revenues are included in the Transmission revenues that are then used to set the Transmission level of operations and maintenance (O&M) expenses. The NITS revenues were overstated by $16.3 million. The Ancillary Services revenues were overstated by

$2.0 million. Figure 1 below shows the filed Direct and corrected Rebuttal NITS and Ancillary Services Revenue amounts.

Figure 1. Filed and Corrected NITS and Ancillary Services Revenues

	NITS Revenues			Ancillary Services Revenues		
	2024 Test Year (As Filed)	Corrected	Difference	2024 Test Year (As Filed)	Corrected	Difference
E-34	$ 12,017,910	$ 7,633,654	$ (4,384,256)	$ 1,492,152	$ 947,800	$ (544,352)
E-35	$ 16,692,700	$ 10,603,033	$ (6,089,667)	$ 2,072,577	$ 1,316,480	$ (756,097)
XHLF	$ 16,130,023	$ 10,245,626	$ (5,884,397)	$ 2,002,715	$ 1,272,104	$ (730,611)
E-34 AG-X APS RA	$ 94,508	$ 99,481	$ 4,972	$ 10,960	$ 12,352	$ 1,392
E-35 AG-X APS RA	$ 122,378	$ 128,816	$ 6,438	$ 14,192	$ 15,994	$ 1,802
	$ 45,057,520	$ 28,710,610	**$ (16,346,910)**	$ 5,592,596	$ 3,564,729	**$ (2,027,866)**

The correction to the NITS revenue results in a $16.3M reduction to the final ACC jurisdictional revenue requirement. Since the Ancillary revenues are a reclassification from Demand Production, the impact is limited to the allocation difference between the two reclass lines, multiplied by the $2.0 million correction. Figure 2 below shows the revenue requirement impact of both corrections.

Figure 2. Corrected NITS and Ancillary Services Revenue Impact to Revenue Requirement

Impact on Revenue Requirement				
		Incremental	Cumulative	% Base Rate Increase
Requested Base Rate Increase (As Filed)			$ 662,439,714	15.99%
NITS Expense Reduction	$	(16,346,910)		
Ancillary Expense Reduction	$	(2,027,866)		
Demand Production Offset (99.91% Retail)	$	2,026,041		
Net Ancillary Expense Reduction	$	(1,825)		
Gross Expense Reduction (NITS + Ancillary)	**$**	**(16,348,735)**		
Total Impact on Revenue Requirement	**$**	**(16,348,735)**	$ 646,090,979	15.59%

Second, there was an additional amount of capacity-related Power Purchase Agreement (PPA) costs that did not get allocated on demand production. Within the COSS, the demand related PPA costs are reclassified from an energy allocation to a demand allocation. The COSS provided in the Application included

$46.9 million of additional such costs that should have been reclassified. The revenue requirement impact of this change is an increase of approximately $33,000.

Third, there was a tranche of solar production in the amount of 2,723 MWh that was omitted from the Value of Solar calculation. This correction increased the Value of Solar production by $119,000 dollars within the Solar Credit.

Fourth, line 46 in the COSS calculates a percentage of the cost to serve each customer class. This percentage reflects the revenues received in the Test Year divided by the revenue requirement for each respective class, inclusive of adjustor revenue and expense used in any transfers to base rates. Since this number illustrates how far above or below each class is relative to their cost to serve, it is used as an input for rate design in the allocation of requested revenue changes. Within the COSS, the percentage cost to serve calculation in JRM_WP04DR and JRM_WP05DR inadvertently referenced adjustor revenue and expense that did not align with the proposed adjustor transfers into base rates for this case. There was no impact to the revenue requirement, calculated deficiency, or requested rate increase as a result of this error. Figure 3 below shows the change associated with each rate class's cost to serve.

Figure 3. Corrected Percentage Cost to Serve Results

	Application	Corrected	Difference
TOTAL ELECTRIC	87.20%	86.40%	-0.80%
TOTAL OTHER	44.80%	44.70%	-0.10%
TOTAL ACC JURISDICTION	88.80%	88.00%	-0.80%
TOTAL RESIDENTIAL	75.10%	74.40%	-0.70%
GENERAL SERVICE	110.70%	109.70%	-1.00%
E-221 NonAG	122.40%	119.30%	-3.10%
E-221 AG	108.20%	104.80%	-3.40%
STREET LIGHTING	108.80%	108.20%	-0.60%
DUSK TO DAWN	64.00%	63.90%	-0.10%
Legacy Solar (Energy)	35.40%	35.10%	-0.30%
Legacy Solar (Demand)	69.00%	68.40%	-0.60%
R-Solar (TOU)	52.00%	51.60%	-0.40%
R-Solar (Demand)	60.00%	59.50%	-0.50%
R-Basic (0-600 kW)	61.80%	61.30%	-0.50%
R-Basic (601-999 kW)	80.30%	79.70%	-0.60%
R-Basic (1000+ kW)	109.90%	109.00%	-0.90%
R-TOU	84.90%	84.20%	-0.70%
R-Demand	82.20%	81.40%	-0.80%
E-20 (Church Rate)	85.60%	83.60%	-2.00%
E-32 TOU (0-20 kW)	151.60%	150.90%	-0.70%
E-32 TOU (21-100 kW)	177.20%	175.90%	-1.30%
E-32 TOU (101-400 kW)	140.90%	139.60%	-1.30%
E-32 TOU (401+ kW)	124.70%	123.40%	-1.30%
School TOU	100.30%	98.30%	-2.00%
E-30, E-32 (0-20 kW)	130.20%	129.30%	-0.90%
E-32 (21-100 kW)	139.10%	137.50%	-1.60%
E-32 (101-400 kW)	128.90%	127.60%	-1.30%
E-32 32 (401+ kW)	111.10%	109.80%	-1.30%
E-34	84.10%	83.40%	-0.70%
E-35	81.20%	80.60%	-0.60%
XHLF	69.50%	69.10%	-0.40%
AG-X GSP RA	0.00%	0.00%	0.00%
AG-X APS RA	86.20%	86.80%	0.60%

Changes 1% or less
Changes between 1% and 2%
Changes greater than 2%

VI. REVENUE REQUIREMENTS

Q. PLEASE SUMMARIZE THE PROPOSED CHANGES TO ADJUSTED TEST YEAR OPERATING INCOME, RATE BASE, AND RATE OF RETURN.

A. Figure 4 below sets forth the major components of the changes (numbers have been rounded for ease of presentation). The income statement and rate base pro forma adjustments are discussed in the Rebuttal Testimonies of APS witnesses Jessica E. Hobbick and Ms. Blankenship. The net increase in annual revenue requested in Rebuttal is $611.3 million, which equates to a 14.75% average net bill impact.

Figure 4. APS Revised Revenue Requirement[1]

APS Revised Revenue Requirement	Dollars ($MM)	Bill Impact
Total Revenue Deficiency in APS's Application	662.4	15.99%
Rebuttal Base Rate Impact		
Income Statement and Rate Base Pro Forma Changes		
Update Post Test Year Plant with 12 Months of Actual Costs	79.5	1.92%
Remove Normalization and 50% of Cash Incentive Expense	(21.3)	-0.51%
Update Amortize Limited Income Discount Accumulation to Reflect Actual 2025 Costs	5.2	0.13%
Update Normalize Employee Benefits to Reflect Actual 2025 Costs	(3.9)	-0.09%
Update Cholla Decommissioning to Account for Known Adjustments	3.6	0.09%
Update Palo Verde Lease Buyback to Reflect Actual Costs	1.9	0.05%
Remove 50% of Board of Directors Expense	(1.6)	-0.04%
Update Normalize Wildfire Mitigation O&M Costs to Reflect Actual 2025 Costs	(0.9)	-0.02%
Misc. Adjustments	(0.7)	-0.02%
Changes to Requested Returns		
Decrease in Return on FVI to 0.9%	(12.2)	-0.29%
Other		
Corrections to COSS Model noted in APS Response to Staff 4.9	(18.0)	-0.43%
Revised Base Increase	**694.2**	**16.76%**
Adjustor Impact		
Adjustor Transfers	(82.9)	-2.00%
Revised Net Base Revenue Increase	**611.3**	**14.75%**

[1] Numbers in the figure have been rounded for ease of presentation.

VII. PROPOSED BASE FUEL RATE

Q. WERE ANY ISSUES RAISED REGARDING THE INCREASE TO THE BASE FUEL RATE?

A. State of Arizona witness Caryn Potter incorrectly asserted that the Base Fuel rate was increasing by 85%.[2] The Company's proposal increases the current Base Fuel and purchase power rate of $0.038321/kWh (as authorized by the Commission in Decision No. 79293) [3] to $0.043881, an increase of $0.005560 or 14.5%.

VIII. COST OF SERVICE STUDY

Q. IS THE AVERAGE AND PEAK (A&P) METHODOLOGY USED BY APS RECOGNIZED IN THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (NARUC) ELECTRIC UTILITY COST ALLOCATION MANUAL (NARUC MANUAL)?

A. Yes, Average and Peak (A&P) is one of the prescribed methods under energy weighting methods in the NARUC Manual, specifically in the judgmental energy weightings. The NARUC Manual states: "Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally established energy weighting into cost studies. One example is the 'Peak and Average demand' allocator derived by adding together each classes' contribution to the system peak demand (or to a specified group of system peak demands; *e.g.,* the 12 monthly CPs) and its

[2] State of Arizona, Direct Testimony of Caryn Potter (Mar. 18, 2026) at 19.

[3] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Prop. for Ratemaking Purposes*, Docket No. E-01345A-22-0144 (APS 2022 Rate Case), Decision No. 79293 (Mar. 5, 2024) (Decision No. 79293).

average demand."[4] The A&P methodology used in this case was approved in both of APS's last two rate cases (Decision No. 78317[5] and Decision No. 79293). [6]

Q. DOES A&P CAUSE A MISALLOCATION OF COSTS?

A. No. Costs are not "misallocated" with the use of one method over another. The NARUC Manual acknowledges there are many appropriate ways to allocate costs, each with a different outcome. The appropriate allocation method depends on the facts and circumstances relevant to a utility's cost to serve its customers. In Decision Nos. 78317 and 79293, the Commission found that A&P is more equitable because of the emphasis on coincident peak (CP) instead of non-coincident peak (NCP).[7] The Commission noted that Average and Excess (A&E) disproportionately allocates production costs to customers with lower load profiles, such as schools and churches.[8] This is because schools can have larger demands in the morning during non-peak hours but their load falls significantly before APS's system starts to experience high load. The NCP fails to take this into consideration when allocating costs.

Q. DOES APS HAVE ANY COMMENTS ON THE USE OF THE A&E METHODOLOGY FOR THE PURPOSE OF THIS RATE CASE PROCEEDING?

A. Yes. The use of A&E was last authorized almost a decade ago in Decision No. 76295 (approved in 2017). [9] While A&E is an acceptable method found in the

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[4] NARUC Manual (Jan. 1992) at 57.

[5] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Prop. for Ratemaking Purposes*, Docket No. E-01345A-19-0236, Decision No. 78317 (Nov. 9, 2021) (Decision No. 78317).

[6] *Id.* at 234 and Decision No. 79293 at 249.

[7] *Id*.

[8] Decision No. 78317 at 234

[9] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Property for Rate Making Purposes,* Docket No. E-01345A-16-0036, Decision No. 76295 (Aug. 18, 2017) (Decision No. 76295).

NARUC Manual, it states that NCP should be used for this allocator because the use of a four coincident peak (4CP) produces an allocation factor that is identical to those derived using a pure demand method. For these reasons, reverting to A&E 4CP would be suboptimal in this rate case especially given current unprecedented load growth among large, high load factor customers. These customers use large amounts of energy virtually around the clock, so A&E allocation methods that emphasize 4CP less appropriately capture the significant drivers of cost increases within APS's system.

Q. IS A&P THE MOST APPROPRIATE ALLOCATOR FOR PRODUCTION COSTS IN THIS CASE?

A. Yes. A&P is the most appropriate allocator at this time. Considering the growth of large, high load factor customers, such as data centers, occurring in APS's service territory, A&P better aligns costs with causation because of the recognition that energy loads are an important part of production plant costs. As stated in Decision No. 79293:

> "These generating units that are operated to serve baseload demand are also operated to serve peak demand. Although the baseload demand (i.e., average demand) is not included in the second bucket under the A&E method, in reality, the average/baseload demand does not magically vanish during times of peak demand. It is still very much present. Thus, while high-load-factor customers' usage is not 'peaky,' it absolutely contributes greatly to peak demand costs, and that contribution must be represented in the allocation of production demand costs to ensure that all customer classes are paying their fair share. The Commission continues to believe that the A&P method, which includes the average demand portion of the peak demand in the second bucket, provides a fairer allocation of production demand costs than does the A&E method." [10]

[10] Decision No. 79293 at 248.

The Commission also noted that the "addition of the XHLF customers anticipated to be served by APS's system would make the A&P-4CP method even more appropriate to use for production cost allocation in future rate cases than it is in this rate case."[11]

Q. FOR THE PURPOSES OF THIS RATE CASE, IS THE A&P METHODOLOGY PROBLEMATIC BECAUSE IT "DOUBLE COUNTS" ENERGY?

A. No. As discussed above, A&P is one of the accepted methodologies for energy weighting according to the NARUC Manual. Witnesses on behalf of Walmart Inc. (Walmart), Microsoft Corporation (Microsoft), Federal Executive Agencies (FEA), and Arizona Large Customer Group (AZLCG) assert that A&P double counts energy due to the fact that average demand appears both in the energy component and the peak component.[12] These arguments fail to recognize that, in the context of this rate case where growth among large, high load factor customers is a significant concern, A&P is intentionally different and intended to weigh average demand more heavily in its cost allocation. This is the intended directive of the Commission. As stated in Decision No. 79293: "To be clear, what the Commission meant was that it does not view 'peak demand' as only the 'excess demand' that is included in the second bucket under the A&E method. Rather, peak demand includes both the average demand and the excess demand, i.e., it is consistent with the second bucket under the A&P method."[13]

[11] *Id.* at 249.
[12] APS 2022 Rate Case, Direct Testimony of Jamie R. Moe (Oct. 28, 2022) at 16-17.
[13] Decision No. 79293 at 248.

Q. WERE THERE ANY OTHER ARGUMENTS RELATED TO THE A&P METHODOLOGY?

A. Yes. Western Resource Advocates (WRA) witness Andy Eiden asserts that the A&P-4CP overemphasizes peak demand, which is in contrast to the argument made by other intervenors that this method double counts energy.[14]

Q. PLEASE EXPLAIN HOW THE A&P METHOD ALIGNS RATES WITH COST CAUSATION.

A. Over the Company's last several rate cases, the Commission has consistently held that the A&P method is fair because it distinguishes between both energy and demand usage that each customer class uses concurrently. The Commission has stated that the distinction between energy and demand is a sufficient response to the charge that the A&P method "double counts" energy usage, particularly for large, high load factor customers. The goal of the A&P method is to consider the average energy usage and contribution to peak demand of each customer class when allocating production costs. Although FEA witness Jessica A. York recommends the Commission return to the A&E method as was used in the Company's 2016 rate case proceeding (Decision No. 76295), it is not appropriate for the current growth environment and would not allocate the proper amount of costs to large, high load factor customers. Rather, the A&P method, which has been authorized by the Commission in the last two rate cases (i.e., Decision Nos. 78317 and 79293), should be used because it allocates production costs to each customer class by weighting the classes' average demand and peak demand. The average demand component considers the classes' constant energy usage, and the peak demand component considers the classes' contribution to peak demand.

[14] WRA, Direct Testimony of Andy Eiden (Mar. 18, 2026) (Eiden Direct) at 11-12, 32.

Q. WHY DO MICROSOFT, FEA, AZLCG AND WALMART OPPOSE A&P?

A. The reason large and high-load factor customers oppose A&P is because it appropriately allocates a greater level of costs to them when compared to the A&E methodology they recommend. This is because they cannot escape peak usage cost allocation by having a high load factor. As stated in Decision No. 79293:

> "The Commission is cognizant that the A&P method tends to be disfavored by high-load-factor customers and favored by low-load-factor customers and notes that this pattern appears to exist in this matter as well. The Commission's conclusion herein is not inconsistent with APS's testimony that high summer peak demand continues to be a primary driver of APS's production capacity costs; it is consistent with the reality that high summer peak demand is comprised of both average demand and 'excess demand."[15]

Q. WHICH ALLOCATION METHODOLOGY DO MICROSOFT, FEA, AZLCG, AND WALMART RECOMMEND FOR THE PRODUCTION DEMAND COSTS?

A. These parties recommend the A&E-4CP methodology. FEA recommends the A&E methodology, whether it is based on 4CP or NCP. The problem with the A&E-4CP is that it essentially allocates on 4CP alone, which means that average demand, or energy, is given very little weight with regard to how production demand costs are allocated. As discussed in APS witness Kent C. Walter's Rebuttal Testimony, this simply doesn't reflect the considerations APS currently takes into account when procuring generation resources, which currently emphasizes longer-duration resources.

[15] Decision No. 79293 at 248-49.

Q. HAVE ANY OTHER METHODOLOGIES FOR THE ALLOCATION OF PRODUCTION DEMAND BEEN RAISED?

A. WRA recommends the use of Probability of Dispatch (POD) instead of A&P. The POD allocation is considered a time-differentiated method and is not considered an energy weighting method like A&E or A&P. POD requires substantial data for input and analysis requirements that make it complex to use and understand. There is concern that the POD results can more closely resemble a pure energy allocation rather than a demand-based allocation, and the system peak and summer 4CP are still an important consideration in APS's procurement of resources, notwithstanding the shift in need for longer-duration capacity and energy solutions. Ultimately, this allocator would make the process of allocation less transparent, more difficult to evaluate, and inappropriate under current circumstances. APS maintains that, given the growth of large high load factor customers on its system, allocating production demand costs using A&P is appropriate at this time.

Q. DO YOU AGREE WITH STAFF THAT DISTRIBUTION COSTS SHOULD BE ALLOCATED BASED ON A 4NCP METHOD RATHER THAN THE CURRENT NCP METHOD?

A. No. The distribution system is typically designed to meet a customer class's peak load, regardless of whether that coincides with the system peak. As a result, APS allocates costs related to distribution substation and primary distribution line assets on an NCP basis, which has been accepted in many rate cases.[16] Furthermore, in its discussion of allocating distribution costs, the NARUC

[16] *In the Matter of the Application of Ariz. Pub. Serv. Co. for a Hearing to Determine the Fair Value of the Utility Property for Rate Making Purposes,* Docket No. E-01345A-05-0816, Decision No. 69663 (Jun. 28, 2007); Docket No. E-01345A-08-0172, Decision No. 70667 (Dec. 24, 2008); Docket No. E-01345A-08-0172, Decision No. 71448 (Dec. 30, 2009); Docket No. E-01345A-11-0224, Decision No. 73183 (May 24, 2012); and Decision Nos. 76295, 78317, and 79293.

Manual recommends only the NCP allocation method for demand-related distribution costs.[17] Historically, the only difference has been, per Commission order, a portion of primary and secondary distribution costs are classified on a customer basis for certain accounts.[18]

Q. WERE THERE ANY INTERVENOR COMMENTS ON THE COMPANY'S PROPOSED CHANGE TO THE ALLOCATION OF INCOME TAX EXPENSE?

A. AZLCG and Freeport Minerals Corporation (Freeport) witness Jeffry Pollock recommends that the Commission require income taxes to be allocated on taxable income rather than rate base.[19] He argues that allocation on rate base would only be appropriate if all classes were providing the same rate of return at present rates.

Q. DOES APS AGREE WITH THE RECOMMENDATIONS OF AZLCG AND FREEPORT?

A. No. It is more important to use the rate base allocation of taxes when classes have a diverse range of rates of return from current rates. Based on the proposed revenue requirement, the Company's total income tax expense is set for the determination of rates. All rate classes should bear a share of this expense.

Under the taxable income allocation of taxes, when a class is below their cost of service, their rates are under recovering their revenue requirement. This means their taxable income is lower than it should be (or potentially negative) and that class will then have a lower taxable income and income tax expense. This reduced income tax expense would be due to the fact that their revenues (authorized rates) were insufficient to cover their share of costs, and those income taxes would then be allocated to other classes whose rates are recovering above their cost of service.

[17] NARUC Manual (Jan. 1992) at 97.
[18] Decision No. 78317 at 241.
[19] AZLCG and Freeport, Direct Testimony of Jeffry Pollock (Mar. 18, 2026) at 34.

Thus, to more accurately measure the cost of service and level that classes are above or below their cost of service, the rate base allocation of income taxes is appropriate.

Q. DO YOU AGREE WITH THE CONCERNS EXPRESSED BY INTERVENORS REGARDING AG-X TREATMENT IN THE COSS?

A. No. NRG Energy, Inc. (NRG) witness Lance D. Kaufman recommends that AG-X be modeled into the COSS using only the net energy served by APS, and he suggests significantly lower rates should be charged to AG-X customers for resource adequacy (RA).[20] I disagree with the recommendation as the capacity needed for AG-X customers should be calculated in the same manner that it is for all other APS customers, reflective of their total capacity and energy load. APS' proposal is designed to ensure that AG-X customers who have opted for APS to provide their RA are allocated their fair share of capacity costs and prevent those costs from being spread to other customers.

Dr. Kaufman's argument is premised on the fact that over 99% of the energy AG-X customers consume is served by a Generation Service Provider (GSP). This argument is irrelevant and conflates capacity and energy costs, because APS must always maintain RA for these customers, even if those customers do not always use APS-supplied energy. By way of illustration, Dr. Kaufman's position would be similar to a home hazard insurance customer arguing they should pay for just 1% of annual premiums, because they had one small water pipe burst in their kitchen that only lasted 1% of the hours in the year.

Due to their desire to reduce cost allocation for RA by using net energy, NRG's calculations of recommended rates severely underestimate the cost of providing

[20] NRG, Direct Testimony of Dr. Lance D. Kaufman (Mar. 18, 2026) (Kaufman Direct) at 11.

RA. The reduced rates would benefit NRG, other GSPs, and AG-X customers to the detriment of all other APS customers. As a result of the options for AG-X customers enabled in Decision No. 79293, NRG and other GSPs have the option of providing RA to AG-X customers, which would be the more appropriate alternative.

Given that all AG-X customers currently rely on APS for RA, APS's method appropriately recognizes that the current energy contracts used to serve AG-X customers require significant generation capacity from APS to ensure a reliable supply that meets RA requirements.

Q. DOES NRG HAVE ANY CONCERNS WITH APS'S USE OF THE E-34 GENERATION DEMAND CHARGE TO RECOVER THE COSTS OF ENSURING RA?

A. Yes. NRG's main concern is the contention that both the capacity and energy components of production plant costs are included in the calculation of the rate.[21] Dr. Kaufman recommends APS use its COSS to fully allocate production demand costs to calculate the cost of APS providing RA to AG-X customers rather than referencing the E-34 generation demand charge.

Q. DOES THE E-34 GENERATION DEMAND CHARGE INCLUDE ENERGY COSTS?

A. No. Production demand costs are allocated based on the A&P, which uses both capacity and energy load information to determine allocation. Production energy costs, however, are not included within the production demand costs. The E-34 generation charge does not actually fully recover the production demand costs as a portion of the costs are recovered through energy charges.

[21] *Id.* at 10-12.

Q. HOW DOES APS RESPOND TO NRG'S RECOMMENDATION TO USE APS'S COSS FOR THE CALCULATION OF ITS RA CHARGE RATHER THAN THE E-34 GENERATION DEMAND CHARGE?

A. APS's COSS supports a higher production demand cost for AG-X customers. The COSS supports an E-34 generation demand charge in excess of $23 per kW-month, accompanied by a corresponding reduction in the E-34 energy charge. This structure would increase the production demand charge for AG-X customers as appropriate, but further analysis would be needed to ensure non-AG-X customers would remain at their cost to serve. Alternatively, APS's COSS supports an AG-X specific RA charge of more than $24 per kW-month, which would increase the production demand charge for AG-X customers only.

IX. GROWTH-BASED ALLOCATION

Q. DO ANY INTERVENORS SUPPORT THE COMPANY'S PROPOSED GROWTH ALLOCATION METHODOLOGIES?

A. Yes. Staff witness Anthony Georgis states APS's proposed methodology appears to equitably assign and allocate incremental new generation costs to those customers responsible for the costs. Walmart witness Jaime McGovern, Ph.D also agrees with the Company's proposed methodology. The Arizona Association of School Business Officials, Arizona School Administrators, and Arizona School Boards Association (collectively, Arizona School Associations or School Groups) witness Travis Sarver raised a specific concern regarding the growth methodology, which the Company agrees with. I address this concern further below.

Q. PLEASE EXPLAIN HOW THE GROWTH-BASED ALLOCATION METHOD IS CONSISTENT WITH COST CAUSATION.

A. The Company's proposed growth-based allocation method is grounded in fairness and fundamental cost causation principles. When new generation resources or

power purchases are placed into service to serve new growth, those customers responsible for that growth should be allocated their fair share of those costs, unless those resources were procured to replace retiring generation assets or expiring PPAs. If not for the unprecedented growth the Company is experiencing, APS would not need to procure this level of additional resources. Consequently, since the new resources have higher costs than the historic embedded costs, as discussed by APS witness Michael Eugenis in his Rebuttal Testimony, it is appropriate to assign these costs to the classes based on their growth.

Q. HOW DO YOU RESPOND TO MR. EIDEN'S CONCERNS THAT THIS APPROACH IS LIMITED AND BACKWARD LOOKING?

A. WRA criticizes the Company's proposal due to its reliance on single-year historical growth while explaining that resource decisions are driven by forward-looking Integrated Resource Plan (IRP) needs, not backward-looking ratios. As stated above, the growth-related resources coming online in a year are generally procured to be available for growth that has occurred. There may be some deviations to this, but by putting stakes in the ground for evaluation and using this method year after year through the PSA and Formula Rate Adjustment Mechanism (FRAM) rate adjustments, the Company will be able to allocate growth-related plant and purchase power costs to the classes driving growth. The Company's proposal also allows for these cost determinations to be transparent and easily reviewed.

It is also important to recognize that the Commission regulations for setting rates are framed entirely around a historical test year. This is why APS's FRAM proposal, as described in more detail by Ms. Hobbick in her Direct and Rebuttal Testimonies, is based on a historical measurement period. Adjusting APS's growth-based cost allocation method to account for long-range projections of

growth—of the kind used in APS's IRP—would arguably deviate from the Commission's regulations and would almost certainly deviate from accepted ratemaking practices in Arizona. In this respect, APS's proposal better aligns with Commission regulations and accepted practice for Arizona utility ratemaking.

Q. IS APS PROPOSING ANY CHANGES TO THE GROWTH-RELATED DIRECT ASSIGNMENT OF THE BASE FUEL RATE AND THE PSA?

A. APS is not making any changes to the proposed method for direct assignment allocations of the Base Fuel rate discussed in the Company's Application. However, I do propose a change related to updating the Base Fuel Direct Assignment rate annually for the PSA. In my Direct Testimony, I discussed APS's proposal to update each of the Base Fuel Direct Assignment rates each year and reflect the changes in the PSA annual filing. Since base rates, which are inclusive of the Base Fuel rate, are determined and set within the rate case, it is more appropriate to create a Fuel and Purchase Power Direct Assignment rate within the PSA to achieve the desired goal of avoiding growth-related cost shifts that work in the same manner. The use of a Fuel and Purchase Power Direct Assignment rate is a more practical solution to allow for updates in between rate cases. I also propose a conforming change to the proposed PSA Schedule 10.

Q. HOW WOULD THE FUEL AND PURCHASE POWER DIRECT ASSIGNMENT WORK?

A. The Fuel and Purchase Power Direct Assignment Rate would work similarly to the calculation of the Base Fuel Direct Assignment described in my Direct Testimony. First, the costs identified as the growth share of new PPAs coming online in the PSA's forecast year would be calculated and direct assigned across the four groups, Residential, Other General Service, E-34/E-35, and finally XHLF. Next, these costs would be removed from the forecast costs that typically would be recovered through the PSA Forward component. This ensures customer

protection in the mitigation of cost shifts. Both the Fuel and Purchase Power Direct Assignment and the Base Fuel Direct Assignment will ensure that these costs don't flow into the existing three PSA component rates through which costs are evenly spread amongst all customers. As such, the Fuel and Purchase Power Direct Assignment Rate should not be subject to the 6 mil cap associated with the PSA component rates. Please see Attachments JRM-04RB and JRM-05RB. This also addresses intervenor concerns that APS's growth-related direct assignment is only historic looking.

Q. WHY WOULD THE FUEL AND PURCHASE POWER DIRECT ASSIGNMENT BE CALCULATED USING DATA FROM THE PSA FORECAST?

A. The PSA filing includes a forecast year of information, so PPAs that are projected to go into service in that year can be identified at the time of the PSA filing in November. In accordance with the PSA Plan of Administration (POA) implementation date of February 1, the Fuel and Purchase Power Direct Assignment Rate would be updated to ensure the new costs related to the forecasted growth are being contained to and recovered by the classes that are growing. Using data from the year-ahead PSA forecast minimizes the chance that the growth-related costs will flow into the other PSA components, therefore mitigating the potential for cost shifts.

Q. PLEASE EXPLAIN THE CHANGE TO SCHEDULE 10 OF THE PSA'S POA.

A. Figure 5 shows an example of how Schedule 10 of the first PSA filing might look when populated after implementing the Fuel and Purchase Power Direct Assignment Rate. The PSA information, referred to as Year 1 PSA, is hypothetical and used for the purpose of this demonstration.

Figure 5. Illustrative PSA POA Schedule 10 – Initial Filing

Line No.			Residential (a)	Other General Service (b)	Rate Schedules E-34 and E-35 (c)	Rate Schedule XHLF (d)	Total (e)
	Sales Growth Calculation for Year 1 PSA						
1	Forecast Year 1 Growth (kWh)		100,000,000	100,000,000	500,000,000	800,000,000	1,500,000,000
2	Forecast Share of Year 1 growth		6.67%	6.67%	33.33%	53.33%	100.00%
3	Forecast Year 1 Energy (kWh)		15,000,000,000	12,300,000,000	4,400,000,000	3,200,000,000	34,900,000,000
	Recovery of Incremental Direct Assignment Costs for Forward Year (Year 1)						
4	New Incremental Generation Costs - net of ELCC Reduction		$ 8,333,333	$ 8,333,333	$ 41,666,667	$ 66,666,667	$ 125,000,000
5	New Incremental Generation - net of ELCC Reduction (kWh)		100,000,000	100,000,000	500,000,000	800,000,000	1,500,000,000
6	Estimated $/kWh	L 4 / L 5	0.083333	0.083333	0.083333	0.083333	0.083333
7	Base Fuel less New Incr. Generation plus Base Fuel & PP Direct Assignment ($/kWh)		0.043438	0.042980	0.047545	0.047346	
8	Fuel and Purchased Power Direct Assignment Rate		-	-	-	-	
9	Base Fuel less New Incr. Generation plus Base Fuel & PP Direct Assignment Recovery	L 5 * L 7	$ 4,343,804	$ 4,298,021	$ 23,772,498	$ 37,876,488	$ 70,290,810
10	Base Fuel and Purchased Power Direct Assignment Recovery	L 5 * L 8	$ -				
11	Year 1 Remainder	L 4 - L 9 - L 10	$ 3,989,530	$ 4,035,313	$ 17,894,169	$ 28,790,179	$ 54,709,190
12	Total Year 1 Energy (kWh)		15,000,000,000	12,300,000,000	4,400,000,000	3,200,000,000	34,900,000,000
13	Proposed Fuel and Purchased Power Direct Assignment	L 12 / L 11	0.000266	0.000328	0.004067	0.008997	

Q. WHAT CHANGE DIFFERENTIATES THIS VERSION OF SCHEDULE 10 FROM THE SCHEDULES INCLUDED IN THE APPLICATION?

A. The change is limited in scope and relates to the structure of the schedule. Two lines have been added to Schedule 10—the Fuel and Purchase Power Direct Assignment Rate and Fuel and Purchase Power Direct Assignment Recovery lines. These lines separate the Fuel and Purchase Power Direct Assignment component from the Base Fuel Less New Incremental Generation and Base Fuel Direct Assignment combined rates for each class, which allows for the Fuel and Purchase Power Direct Assignment to be adjusted individually to capture any remainder. Figure 6 shows an example of how Schedule 10 of the second PSA filing following the Fuel and Purchase Power Direct Assignment might look. Two years of information are shown so that the previous calculations are available for reference. The additional PSA information, referred to as Year 2 PSA, is also hypothetical and used for the purpose of this demonstration.

Figure 6. Illustrative PSA POA Schedule 10 – Subsequent Filing

Line No.			Residential (a)	Other General Service (b)	Rate Schedules E-34 and E-35 (c)	Rate Schedule XHLF (d)	Total (e)
	Sales Growth Calculation for Year 1 PSA						
1	Forecast Year 1 Growth (kWh)		100,000,000	100,000,000	500,000,000	800,000,000	1,500,000,000
2	Forecast Share of Year 1 growth		6.67%	6.67%	33.33%	53.33%	100.00%
3	Forecast Year 1 Energy (kWh)		15,000,000,000	12,300,000,000	4,400,000,000	3,200,000,000	34,900,000,000
	Recovery of Incremental Direct Assignment Costs for Forward Year (Year 1)						
4	New Incremental Generation Costs - net of ELCC Reduction		$ 8,333,333	$ 8,333,333	$ 41,666,667	$ 66,666,667	$ 125,000,000
5	New Incremental Generation - net of ELCC Reduction (kWh)		100,000,000	100,000,000	500,000,000	800,000,000	1,500,000,000
6	Estimated $/kWh	*L 4 / L 5*	0.083333	0.083333	0.083333	0.083333	0.083333
7	Base Fuel less New Incr. Generation plus Base Fuel & PP Direct Assignment ($/kWh)		0.043438	0.042980	0.047545	0.047346	
8	Fuel and Purchased Power Direct Assignment Rate		-	-	-	-	
9	Base Fuel less New Incr. Generation plus Base Fuel & PP Direct Assignment Recovery	*L 5 * L 7*	$ 4,343,804	$ 4,298,021	$ 23,772,498	$ 37,876,488	$ 70,290,810
10	Base Fuel and Purchased Power Direct Assignment Recovery	*L 5 * L 8*	$ -				
11	Year 1 Remainder	*L 4 - L 9 - L 10*	$ 3,989,530	$ 4,035,313	$ 17,894,169	$ 28,790,179	$ 54,709,190
12	Total Year 1 Energy (kWh)		15,000,000,000	12,300,000,000	4,400,000,000	3,200,000,000	34,900,000,000
13	Proposed Fuel and Purchased Power Direct Assignment	*L 12 / L 11*	0.000266	0.000328	0.004067	0.008997	
	Sales Growth Calculation for Year 2 PSA						
13	Forecast Year 2 Growth (kWh)		100,000,000	100,000,000	500,000,000	800,000,000	1,500,000,000
14	Forecast Share of Year 2 growth		6.67%	6.67%	33.33%	53.33%	100.00%
15	Forecast Year 2 Energy (kWh)		15,100,000,000	12,400,000,000	4,900,000,000	4,000,000,000	36,400,000,000
	Recovery of Incremental Direct Assignment Costs for Forward Year (Year 2)						
16	New Incremental Generation Costs - net of ELCC Reduction		$ 10,000,000	$ 10,000,000	$ 50,000,000	$ 80,000,000	$ 150,000,000
17	New Incremental Generation - net of ELCC Reduction (kWh)		100,000,000	100,000,000	500,000,000	800,000,000	1,500,000,000
18	Estimated $/kWh	*L 16 / L 17*	0.100000	0.100000	0.100000	0.100000	0.100000
19	Base Fuel less New Incr. Generation plus Base Fuel & PP Direct Assignment ($/kWh)		0.043438	0.042980	0.047545	0.047346	
20	Fuel and Purchased Power Direct Assignment Rate	*Ln 13*	0.000266	0.000328	0.004067	0.008997	
21	Base Fuel less New Incr. Generation plus Base Fuel & PP Direct Assignment Recovery	*L 17 * L 19*	$ 4,343,804	$ 4,298,021	$ 23,772,498	$ 37,876,488	$ 70,290,810
22	Base Fuel and Purchased Power Direct Assignment Recovery	*L 17 * L 20*	$ 26,597	$ 32,807	$ 2,033,428	$ 7,197,545	$ 9,290,377
23	Year 2 Remainder	*L 16 - L 21 - L 22*	$ 5,629,600	$ 5,669,172	$ 24,194,074	$ 34,925,967	$ 70,418,813
24	Total Year 2 Energy (kWh)		15,100,000,000	12,400,000,000	4,900,000,000	4,000,000,000	36,400,000,000
25	Proposed Fuel and Purchased Power Direct Assignment	*L 23 / L 24*	0.000373	0.000457	0.004938	0.008731	

Q. HOW DOES APS RESPOND TO MS. POTTER'S CONCERN THAT THE CALCULATION OF THE DIRECT ASSIGNMENT IS ATTRIBUTED TO ALL CUSTOMER CLASSES?

A. The Company's proposed methodology establishes fair treatment for all classes of customers based on class growth. Ms. Potter's concern is specific to the inclusion of the residential class in the calculations, noting that other states have limited direct assignment of costs to only the largest load customers. However, the residential class is also expected to grow in APS's territory. As such, it is appropriate that they, along with all other classes, are included in the direct assignment calculations to ensure their generation needs are weighted accordingly.

Q. PLEASE RESPOND TO MICROSOFT'S REJECTION OF GROWTH-RELATED ADJUSTMENTS TO BASE FUEL AND PPA ADJUSTMENTS.

A. Microsoft witness Dr. Larry Blank rejects the Company's proposal for growth-related direct assignment on the basis that PPAs are typically shorter in duration than rate-based investments.[22] However, the duration of a PPA does not undermine the appropriateness of allocating its costs based on the customers whose load growth necessitated the resource. In practice, many PPAs extend for 15 to 20 years and are long term commitments entered into for the purpose of reliably serving incremental load.

More importantly, the proposed growth-based allocation is not driven by the financing structure or term of the resource, but by cost causation. Regardless of whether incremental generation is procured through a PPA or owned generation, those resources are required to serve new load. Allocating these costs based on growth helps ensure that customers driving the need for additional supply bear an appropriate share of those costs. This approach reduces the risk of cost shifting and aligns cost recovery with the underlying drivers of system expansion.

Q. PLEASE RESPOND TO RESIDENTIAL UTILITY CONSUMER OFFICE'S (RUCO) DISCUSSION OF HOW COSTS ARE ASSIGNED BOTH DIRECTLY AND THROUGH BROADER ALLOCATION METHODS IN THE COST OF SERVICE PROCESS.

A. RUCO witness Dustin Madsen does not oppose growth-based cost allocation in principle but recommends an approach involving far more granular cost identification and tracking to accomplish this allocation. APS's proposal is designed to appropriately apply established cost of service principles by directly assigning -related generation costs where feasible and allocating remaining

[22] Microsoft, Direct Testimony of Dr. Larry Blank (Mar. 18, 2026) (Blank Direct) at 31.

system costs in a consistent and transparent manner. In addition, APS has other approaches related to transmission and distribution costs to address the risk of growth-related cost shifts (see below regarding APS's Service Schedule 3; Ms. Hobbick, in her Rebuttal Testimony, discusses APS's approach to addressing transmission costs).

Generation resources and other system investments are planned and procured to serve overall system needs rather than being dedicated at the outset to a specific customer or class. In these circumstances, allocating costs using recognized allocation factors ensures that costs are recovered in a manner that reflects how the system is used. At the same time, APS's proposal incorporates growth-based direct assignment to better align cost responsibility with the customers driving incremental load and associated resource needs.

By combining direct assignment for growth-related costs with traditional allocation for shared system costs, APS's approach captures an appropriate share of supporting costs across customer classes, promotes consistency within the cost of service framework, and minimizes the potential for cost shifts related to growth.

Q. DOES THE PROPOSED GROWTH BASED ALLOCATION METHODOLOGY INCREASE THE RISK OF INTRA-CLASS SUBSIDIES BETWEEN NEW AND EXISTING CUSTOMERS?

A. No. The proposed growth-based allocation methodology is intended to reduce the potential for class subsidization. By aligning the cost for new generation and related resources with the customer classes driving incremental growth, the proposed methodology helps ensure that growth-related costs are not borne by

other customers. This is discussed in greater detail in Ms. Hobbick's Rebuttal Testimony.

To mitigate risks for any potential intra-class subsidies, APS also requires demand and energy-based minimum contract terms within service agreements for large, high load factor customers, as discussed further in Rebuttal Testimony from Mr. Tetlow, Mr. Bauer, and Ms. Hobbick, to reduce the risk of intra-class subsidies. As such, if these customers deviate from planned load ramps, reduce usage, or leave APS's service territory altogether, governing minimum demand and energy usage terms and other financial protections within APS's service agreements will ensure costs are still recovered from the customer who caused their incurrence. This serves to mitigate the risk of intra-class subsidization.

In general, rate classes are nonetheless designed to group customers by similar size (energy and demand), usage patterns, and service characteristics, recognizing that no two customer classes are identical. Within each class, customers collectively share the costs and benefits associated with serving the class based on common cost-causing characteristics. The fact that some customers are newer to the system or that some customers' usage changes over time does not negate the effectiveness of class-based rate design. This construct is a foundational element of all cost-of-service rate making and is not unique to the proposed growth-based allocation.

Q. WOULD IT BE MORE APPROPRIATE FOR THE COMPANY TO IMPLEMENT THIS PROPOSAL IN A FUTURE RATE CASE AS SUGGESTED BY FEA?

A. No. The Company continuously evaluates system conditions and incorporates new information as it becomes available to plan for and reliably serve customer

needs. At the same time, the Company is experiencing unprecedented actual and forecasted load growth, being significantly driven by large, high load factor customers, such as data centers. Indeed, in March of this year, President Trump, along with many leading artificial intelligence and datacenter companies, signed the Ratepayer Protection Pledge in an effort to help hold harmless existing electric customers from potential rate increases stemming from data center needs. In light of this impending challenge, and in line with APS's focus on protecting existing customers, the Company has chosen to proactively modify APS's allocation methodology to ensure that growth pays for growth.

Furthermore, not all of the growth-related investments are taking place in the future. The Company proposes to directly allocate $547 million of plant investment that was placed in service in 2025 alone, based on resource accreditation analysis performed by Mr. Eugenis in his Rebuttal Testimony. Please see Figure 7 below for a breakdown of these costs. These investments were necessary to serve growth during the Test Year and if not for the Company's growth-based allocation methodology, would be collected from all customers via APS's historical allocation methods. Postponing the Company's proposal would cause growth-related costs to be spread across all customers and simply kick the can down the road despite the fact that APS has already invested in growth-related plant and executed growth-related PPAs.

Figure 7. 2025 Growth-Related Generation Plant Additions

Line No.	2025 Growth-Related Generation Plant Additions		
1	Total ELCC for 2025 New Incremental Generation (MW)		1,699
2	Cholla - Capacity/Reliability Accreditation Value (MW)		380
3	New Incremental Generation Retirement Reduction Factor	(Ln 2 / Ln 1)	22.37%
4	Agave Battery Energy Storage System	Total Cost	$ 240,318,205
5	Ironwood Solar	Total Cost	$ 288,688,440
6	Sundance Modernization	Total Cost	$ 175,234,400
7	Total New Generation Plant Additions	Lines 4-6	$ 704,241,046
8	Retired Replacement	(Ln 7 * Ln 3)	$ 157,550,332
9	2025 Growth-Related Generation Plant Additions	(Ln 7 - Ln 8)	$ 546,690,714

Q. HOW DO YOU RESPOND TO WALMART'S CONCERNS THAT THE COST SHIFT PROTECTION PROPOSED BY THE COMPANY'S DIRECT ASSIGNMENT IS NULLIFIED IF THE GROWTH DOES NOT MATERIALIZE?

A. As discussed in Ms. Hobbick's testimony, the Company imposes minimum demand and energy thresholds into its agreements with large, high load factor customers, along with other key financial terms (described in more detail within Mr. Bauer's Rebuttal Testimony) to mitigate this concern. Through these minimums and other key financial terms, the costs associated with serving large, high load factor customers will continue to be recovered in alignment with the direct assignment, even if the customers fall behind schedule in their ramping, reduce usage, or otherwise leave APS's service territory.

Q. MICROSOFT RECOMMENDS TRACKING THE REVENUES ASSOCIATED WITH MINIMUM CHARGES. HOW DO YOU RESPOND?

A. This recommendation is both complicated and unnecessary. Minimum charges have long been part of APS's rate design for its large customers and are not new. Revenue recovered through minimums is included in the base rate revenue for this case within the proof of revenue, and that would continue in the future. These

revenues will also be included in the proposed FRAM and part of the respective rate class's revenue requirement when the COSS is updated annually to determine any deficiency. Tracking the revenues within a regulatory liability as recommended by Microsoft would actually defer those revenues and prevent them from being attributed to the class, thereby creating a larger deficiency.[23]

Q. DO YOU AGREE WITH FEA'S ASSERTION THAT HIGH LOAD FACTOR CUSTOMER CLASSES, WHO USE A LARGER PORTION OF THEIR ENERGY DURING LOWER COST TIMES, SHOULD NOT CONTINUE TO PAY THE AVERAGE FUEL COST?[24]

A. No. The proposed allocation method treats all classes equally, based on their growth, irrespective of what part of the day that energy is consumed. The allocation method also ensures all growth-related generation costs, regardless of whether the generation resources are APS- or third-party owned, are allocated to the rate classes that drive the need to procure them. Consistent with the intentions expressed by both the Commission and the federal government to protect existing customers from data center growth related rate increases, allocating fuel and purchase power costs to all classes based on growth, and not time of day, is the most appropriate approach.

Q. DO YOU AGREE WITH MICROSOFT'S POSITION THAT LOAD GROWTH SPREADS FIXED COSTS AND REDUCES RATES?

A. Not necessarily. The concept of new customers' additional load reducing rates for existing customers presupposes the new incremental revenues being greater than the incremental costs to the system.

This is achieved when the Company has either excess capacity to serve the new load or the ability to procure additional resources at costs lower than the existing

[23] Blank Direct at 5.

[24] FEA, Direct Testimony of Jessica A. York (Mar. 18, 2026) at 8.

system-wide average cost. Neither of those conditions exist today. Mr. Eugenis provides substantiation in his Rebuttal Testimony for the fact that new generation resources, whether procured via purchase power or an APS-owned resource, are significantly more expensive today than embedded system production or generation costs.

Q. DO YOU AGREE WITH SCHOOL GROUP'S RECOMMENDATION TO TREAT THE RATE CLASSES WITHIN APS'S OTHER GENERAL SERVICE CLASS SIMILAR TO HOW RESIDENTIAL IS TREATED?

A. Yes. School Group's concern with interclass movement impacting estimated growth determinations is reasonable.[25] To be responsive to this concern, APS has made an adjustment to the COSS in my Rebuttal Testimony to evaluate the total Other General Service class as a whole instead of by individual class (*see* Figure 8).

Figure 8. Revised Growth Impacts for General Service

Average and Peak Retail Allocation

	Other General Service Broken Out	Other General Service Combined	Difference
E-20 (Church Rate)	0.11%	0.11%	0.00%
E-32 TOU (0-20 kW)	0.06%	0.06%	0.00%
E-32 TOU (21-100 kW)	0.07%	0.07%	0.00%
E-32 TOU (101-400 kW)	0.29%	0.29%	-0.01%
E-32 TOU (401+ kW)	0.87%	0.84%	-0.03%
School TOU	0.75%	0.67%	-0.08%
E-30, E-32 (0-20 kW)	4.58%	4.61%	0.03%
E-32 (21-100 kW)	7.16%	7.22%	0.06%
E-32 (101-400 kW)	8.76%	8.65%	-0.11%
E-32 (401+ kW)	7.05%	7.17%	0.12%
AG-X GSP RA	0.00%	0.00%	0.00%
AG-X APS RA	1.64%	1.65%	0.01%
Total General Service	**43.94%**	**43.93%**	**-0.01%**

[25] School Groups, Direct Testimony of Travis Sarver (Mar. 18, 2026) at 16-18.

Q. PLEASE RESPOND TO WRA'S CONCERN THAT THE GROWTH CALCULATIONS CONTAINED AN ERROR [26]

A. APS confirmed that its calculations are correct, but discovered that the Company inadvertently provided an incorrect version of the 2023 Load Research Report in its response to APS Initial 1.27, which was used by WRA. APS has supplemented its response to APS Initial 1.27 with a corrected version of the 2023 Load Research Report.

Q. HOW IS THE COMPANY ENSURING GROWTH PAYS FOR GROWTH IN THE DISTRIBUTION SPACE?

A. The line extension policy in the Company's Schedule 3 already accounts for distribution growth considerations. When customers request a line extension, an Economic Feasibility study is performed analyzing the costs versus expected distribution revenues based on the expected load from a given customer distribution line extension project. To the extent that the customer's revenues do not recover the costs of the line extension, the customer is responsible for paying for the capital costs through either a contribution or advance in aid of construction.

X. SITE-LOAD COSS

Q. IS APS'S SITE LOAD COSS BASED ON ACCURATE DATA?

A. Yes. APS's Site Load COSS, which was ordered by the Commission in Decision No. 79293,[27] is based on actual metered customer data. Site load represents the total electrical load of customers, whether that energy is served by the customer's DG system or APS. It does not reflect hypothetical or theoretical load. As noted by the Commission, APS provides RA for DG customers based on their site load.[28]

[26] Eiden Direct at 41-42.
[27] Decision No. 79293 at 448.
[28] *Id.* at 271-72.

The site load is used in the determination of a gross load forecast and in allocating both capacity- and energy-related costs. Solar credits based on avoided fuel and purchase power costs are then applied to reduce the capacity portion below the total calculated site load, but still higher than the amount of energy actually delivered to the customer. The solar credit effectively aligns energy cost recovery with the amount of power actually required for the customer.

This approach recognizes the capacity costs that the Company must keep available as backup to serve DG customers' electricity if their DG system is unavailable, and at the same time acknowledges some capacity value for the customers' DG systems based on an industry-standard Effective Load Carrying Capability (ELCC) calculation. ELCC is further discussed in detail by Mr. Eugenis in his Rebuttal Testimony.

Q. DO YOU AGREE WITH VOTE SOLAR THAT SOLAR EXPORTS MUST BE REMOVED FROM THE SOLAR CREDIT ANALYSIS IN THE SITE LOAD COSS? [29]

A. No. Solar exports that are purchased by APS create a cost for all customers while the value of the power reflects a cost savings. The cost of exports, such as the purchased price under the Resource Comparison Proxy (RCP) rate schedule, represents direct cost obligations to the other customer classes. Likewise, the benefits of solar exports, such as the reduction in fuel costs, represent a direct cost savings to other customer classes. Therefore, the overall net value is relevant to, and an important part of, determining the cost deficiency, if any, for solar classes and their impact on other classes.

[29] Vote Solar, Direct Testimony of Kate Bowman (Mar. 18, 2026) (Bowman Direct) at 7, 63.

Q. DO YOU AGREE WITH VOTE SOLAR THAT SEPARATING RESIDENTIAL DG CUSTOMERS IS AN ARBITRARY DIVISION OF AN OTHERWISE COHERENT CUSTOMER CLASS?[30]

A. No. Separating residential DG customers from non-DG customers is not an arbitrary division, and residential DG customers are not in any way analogous to customers that install energy-saving household appliances. A solar panel array that produces energy for self-consumption and generates energy to export to the grid is not the same as an energy-efficient washing machine or extra thick blinds. The Site Load COSS captures the actual electricity consumption of all customers, including DG customers, as well as the energy that DG customers sell back to APS. It does not capture hypothetical savings from energy-savings household appliances but rather captures the actual consumption of the customers who have installed those appliances. According to the Commission's findings in Decision No. 79293, DG customers "are partial requirements customers and thus a separate class for purposes of the COSS."[31] Moreover, the Commission determined that DG customers do not receive the same or substantially similar service as non-DG customers under like circumstances.[32]

Q. ARE THERE OTHER FEATURES OF RESIDENTIAL DG CUSTOMERS THAT JUSTIFY THE COMMISSION'S DECISION TO PLACE RESIDENTIAL DG CUSTOMERS INTO THEIR OWN CUSTOMER CLASS?

A. Yes. The Commission has also determined that DG customers have their own load pattern and create their own median load peak in the summer that occurs at a

[30] *Id.* at 18-19.
[31] Decision No 79293 at 285.
[32] *Id.* at 285-86.

different time than non-DG customers. Additionally, as previously noted, APS must back up the DG customers' load.[33]

Q. DO APS'S SOLAR CHARGES CAUSE RESIDENTIAL DG CUSTOMERS TO PAY MORE THAN NON-DG CUSTOMERS FOR THE SAME ENERGY USAGE?

A. No. As noted previously, residential DG customers and non-DG customers are two different customer classes. As such, their costs should not be identical. Vote Solar's claim is that a customer with rooftop solar will pay more for their delivered electricity usage than a comparable customer without rooftop solar.[34] This is not an apples-to-apples comparison.

Q. CAN YOU PROVIDE AN APPLES-TO-APPLES COMPARISON?

A. Yes. Breaking down the difference in energy consumption and annual bills for an average residential DG customer with and without solar demonstrates the difference that DG customers pay in base rates. These values can be seen in Figure 9 below.

[33] *Id.* at 286.

[34] Bowman Direct at 13

Figure 9. TOU-E Solar Average Customer Bill No-Solar versus Solar

Month	TOU-E without Solar		TOU-E with Solar		Difference %	
	kWh	*Bills*	*kWh*	*Bills*	*kWh*	*Bills*
Jan	1,022	$145	757	$121	-26%	-16%
Feb	845	$122	583	$96	-31%	-21%
Mar	836	$122	525	$89	-37%	-27%
Apr	884	$130	499	$87	-44%	-34%
May	1,202	$196	647	$113	-46%	-43%
Jun	1,847	$288	1,071	$175	-42%	-39%
Jul	2,293	$359	1,380	$224	-40%	-38%
Aug	2,057	$323	1,270	$208	-38%	-36%
Sep	1,682	$265	1,030	$174	-39%	-34%
Oct	1,256	$203	803	$143	-36%	-30%
Nov	826	$120	562	$96	-32%	-20%
Dec	905	$130	648	$107	-28%	-18%
Annual	**15,655**	**$2,403**	**9,775**	**$1,630**	**-38%**	**-32%**

Q. WHAT DOES FIGURE 9 INDICATE REGARDING DG CUSTOMER BILLS?

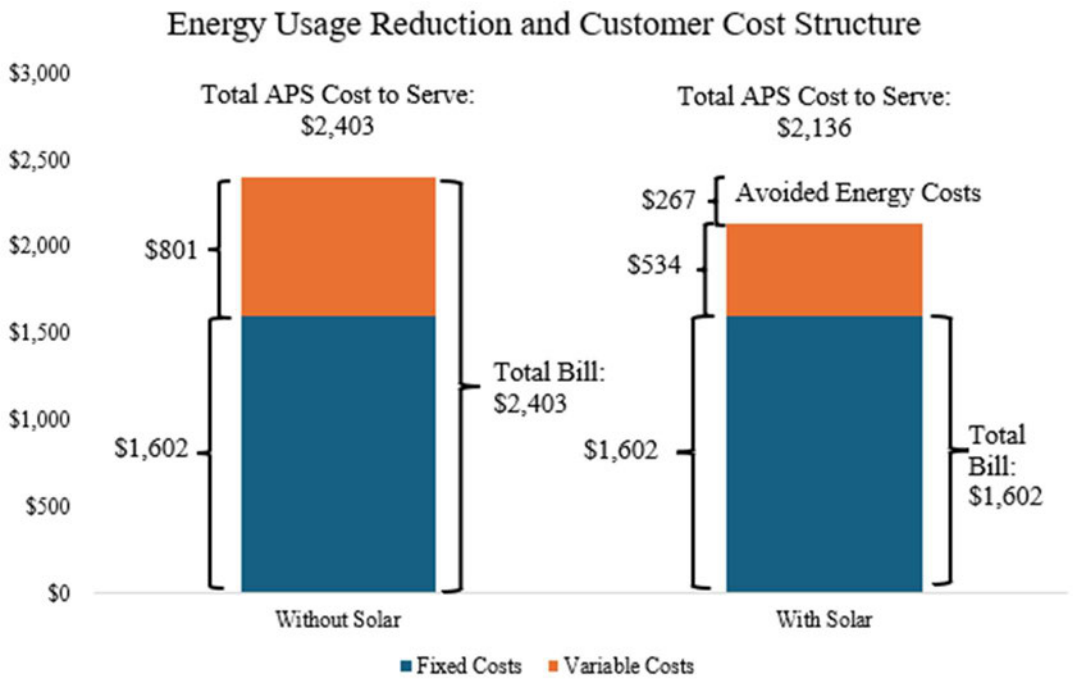
A. Without solar, the average residential DG customer on the TOU-E rate in the Test Year would pay $2,403 in electric bills for 15,654 kWh of electricity. The same customer with a 10 kW DG solar system has billed usage of 9,774 kWh per year and pays $1,630 in annual bills, including the Grid Access Charge (GAC). This means that, on average, a TOU-E solar customer's DG reduces energy usage by about one-third, with a roughly corresponding one-third reduction in annual bills.

Q. THE CUSTOMER REDUCED THEIR USAGE BY ABOUT ONE-THIRD SO THEIR BILL SHOULD REDUCE BY ONE-THIRD. ISN'T THAT A REASONABLE OUTCOME?

A. No. For example, assume the original site load bill for the customer achieves 100% cost of service, and this would be the billing before and after adding solar. The total bill would be the $2,403 (as shown in Figure 9). Traditionally, about

two-thirds (2/3) of total costs to serve the customer are fixed costs that don't change based on usage, such as production plant, transmission facilities, and distribution systems. This is represented by the blue bars in Figure 8 below, totaling $1,602. As for the other one-third (1/3) of total costs, these represent variable costs, costs which do change with usage and largely relate to fuel and purchase power expenses. This is represented by the orange bars in Figure 8, with the full variable costs being $801. In this example, the $267 shown on the right bar (the DG customer with solar) represents the avoided energy costs from the DG customer's one-third reduction in generation, which still leaves $534 of variable energy costs remaining. Thus, $2,136 of total costs would still exist to serve that customer out of the original $2,403. However, based on reducing their energy usage by one-third, the DG customer would only be paying $1,602 of the necessary costs to serve them. Please see Figure 10 below. Note that this calculation is inclusive of the GAC in present rates today.

Figure 10. Impact of Energy Reduction on Fixed and Variable Costs



It is important to recognize that this is a very simple view, and the entirety of the situation is more complex. This does, however, illustrate the basic rationale as to why solar classes recover below the necessary costs to serve when sharing a common rate with non-solar customers.

Q. WHAT OTHER IMPACTS SHOULD BE CONSIDERED?

A. Payments made to residential DG (RCP) customers are another important factor to consider. The RCP export payment further explains why the solar classes are so far below their cost to serve. For example, under the 2017 RCP rate, the average DG customer would be credited around $1,172 in RCP payments per year, reducing their annual bill to around $458. Moving forward, under the most recent 2025 RCP rate, the customer would be credited around $560 in RCP payments, reducing their annual bill to around $1,069. These numbers, along with the RCP tranches not mentioned, are shown in Figure 11 below. Under any tranche, these bill reductions are not in alignment with the recovery of fixed costs APS incurs to serve DG customers as well as the remaining energy costs after self-consumption that APS incurs to serve them. This is a simple illustration demonstrating that the bill reduction and compensation for exports that solar customers receive push them significantly below their cost of service.

Figure 11. Annual Effects of RCP Payments to TOU-E on Cost to Serve

RCP Tranches	RCP Rate	RCP Exports (kWh)	RCP Payments	Solar Bill post-RCP Payments	Solar Bill Savings from Site Load Bill ($)	Solar Bill Savings from Site Load Bill (%)
2017	($0.12900)	9,088	($1,172)	$458	($1,945)	-81%
2018	($0.11610)	9,088	($1,055)	$575	($1,828)	-76%
2019	($0.10450)	9,088	($950)	$681	($1,722)	-72%
2021	($0.09405)	9,088	($855)	$775	($1,627)	-68%
2022	($0.08465)	9,088	($769)	$861	($1,542)	-64%
2023	($0.07619)	9,088	($692)	$938	($1,465)	-61%
2024	($0.06857)	9,088	($623)	$1,007	($1,396)	-58%
2025	($0.06171)	9,088	($561)	$1,070	($1,333)	-55%

Q. VOTE SOLAR ASSERTS THAT IT IS INCONSISTENT TO USE A SITE LOAD COSS FOR RESIDENTIAL DG CUSTOMERS AND A DELIVERED LOAD FOR THE REMAINING CUSTOMER CLASSES.[35] DID APS USE SITE LOAD COSS FOR BOTH?

A. Yes. APS applies a site-load framework consistently across the residential class. For non-DG customers, site load and delivered load are the same because all energy consumed is supplied by APS. For residential DG customers, site load appropriately reflects the total electricity used by the customer, including energy supplied by APS and by the customer's DG system.

The purpose of the Site Load COSS is to measure the total load that APS must plan for and be prepared to serve to ensure reliable service. Residential DG customers remain partial requirements customers who rely on APS to provide capacity, energy, and other system resources whenever their onsite generation is unavailable or insufficient. Using site load therefore ensures that cost

[35] *Id.* at 26-28, 38-39.

responsibility reflects the full level of service the Company must provide for all customers.

The Site Load COSS serves as the starting point for evaluating cost responsibility, after which solar credits are applied to recognize the energy and capacity benefits provided by customer-sited generation. APS acknowledges that site load alone does not reflect those benefits, which is why Solar Credits are calculated and applied. By contrast, relying only on a delivered load approach would fail to recognize the full costs of serving residential DG customers.

Q. VOTE SOLAR ALSO ASSERTS THAT THE COMMISSION HAS FOUND THAT THERE ARE NO ADDITIONAL COSTS TO SERVE DG CUSTOMERS. DO YOU AGREE?[36]

A. No. This characterization oversimplifies and misstates the Commission's findings in Decision No. 79293. As noted previously, the Commission does in fact recognize that "there are additional features of the service provided to rooftop solar customers that must be recognized."[37] Specifically, the Commission determined that APS must maintain generation resources on standby at all times to provide RA to all customers, including residential customers with DG that is unavailable or insufficient to power their home. In particular, during summer months, residential DG customers create a median load peak that occurs later in the day and, at times, exceeds the median load peak of non-DG customers. These features of DG customers give rise to costs that are not captured by a Delivered Load COSS. Vote Solar's argument improperly reframes the issue by focusing on whether APS can identify specific, incremental pieces of equipment or power plants dedicated to DG customers. That is not how a COSS is intended to function,

[36] *Id.* at 26, 31-32.
[37] Decision No. 79293 at 286.

nor is it what the Commission has required. A COSS is designed to fairly allocate existing, system-wide costs among customer classes based on how those classes use and rely on the system, not to identify new assets earmarked to serve a particular group of customers.

This argument also overlooks what the Commission has specifically said regarding this topic. The intervenors are correct that the Commission has stated that, in the context of specifically identifiable assets, "[t]he evidence of record in this matter now makes it clear that APS does not truly provide additional services and does not use additional equipment to serve DG customers." However, these parties neglect to mention what the Commission goes on to state:

> What APS does provide DG customers, however, is RA [Resource Adequacy]. In the same way that APS steps in to serve AG-X customers when their GSPs fail to deliver, APS provides DG solar customers capacity and energy when they need it, but on a larger scale and generally on a much more predictable and consistent basis, although any individual DG system may have diminished production or may cease production at any time due to a multitude of conditions. APS's generation resources stand by at all times to provide capacity to residential DG customers when needed, and residential DG customers use APS's generation resources on a daily basis. Because of this, as it is just and reasonable to allocate production costs to AG-X customers based on their site load, it is also just and reasonable to allocate costs of service to DG customers based on their site load, with credits made based on the difference between the site load and delivered load using the credit factors for each cost type as described in Mr. Moe's testimony.[38]

[38] *Id.* at 271-72.

Q. DON'T ALL CUSTOMERS REQUIRE PLANNING FOR REDUNDANCY AND EXTRA CAPACITY?

A. Yes. It is true that APS provides RA to all customers and that non-DG customer load fluctuates. The critical difference here is that non-DG customers pay their share of RA costs through their monthly bills regardless of load fluctuations. The same is not true for residential DG customers unless the Company uses their site load in the COSS and rates reflect those costs.

Q. DOES IT MATTER THAT SOME UTILITIES IN OTHER JURISDICTIONS HAVE NOT YET ADOPTED A SITE LOAD COSS IN THEIR TREATMENT OF DG CUSTOMERS?

A. No. Although other utilities' methods for evaluating the cost to serve their DG customers may be informative, it is not determinative, given the various unique circumstances of each utility company service territory. APS is unique in that it has a very large residential DG customer base (the Company was ranked 4th nationally for residential solar capacity in 2025) with systems that produce a significant amount of energy given Arizona's high solar radiance values. In light of these circumstances, non-DG customers would be allocated a larger portion of fixed costs if not for the use of DG customers' site load in the COSS. APS has a responsibility to fairly allocate costs to all of its customers based on the characteristics of its system. APS's methodology was approved and authorized by the Commission in Decision No. 79293 after the Commission reviewed both site-load and delivered-load methodologies, and it was subsequently upheld in Decision No. 79648, which included specific evaluation of the site-load approach.[39] As determined by the Commission, this methodology ensures fair and consistent cost allocation across customer classes by reflecting the Commission's finding that allocating costs to DG customers based solely on delivered load fails

[39] *Id.* 79293 at 272; APS 2022 Rate Case, Decision No. 79648 (Dec. 31, 2024) at 50.

to capture the full capacity and other resources APS must maintain to reliably serve those customers when solar generation is unavailable.

XI. SOLAR CREDIT

Q. ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION (ARISEIA) AND VOTE SOLAR TAKE ISSUE WITH HOW APS CALCULATES THE COMPONENTS OF THE SOLAR CREDIT. WHAT IS YOUR RESPONSE?

A. AriSEIA and Vote Solar allege that because components included in the Solar Credits are not calculated in the same manner as those components in the COSS, that APS's calculation of the Solar Credit is invalid.[40] This is incorrect. The methods APS uses for calculating these components captures the unique attributes of DG customers.

Q. PLEASE EXPLAIN THE REASONING BEHIND THE PRODUCTION DEMAND COMPONENT CALCULATION OF THE SOLAR CREDIT.

A. Combining the distinct allocators of 4CP and summer average NCP is intended to calculate a credit that reflects a fair value for the solar capacity provided by DG customers. The production demand component of the Solar Credit is based on the average of the difference between the delivered and site 4CP and NCP. These are used as the basis of the credit to reflect the DG contribution to, and reliance on, system production capacity.

If 4CP alone is used, the credit would essentially arrive back at the delivered load allocation and would not fully capture residential DG customers' use of the system. By also using the summer average NCP, the credit calculation properly considers this important capacity factor to reasonably determine how much of the

[40] Bowman Direct at 47-48, 63; AriSEIA, Direct Testimony of Kevin Lucas (Mar. 18, 2026) (Lucas Direct) at 15-17.

difference between site and delivered load to credit. The use of the NCPs in designing the credit adds an element of diversification for DG customers' reliance on APS's system.

Q. DOES THIS REASONING ALSO EXPLAIN THE RATIONALE FOR THE DISTRIBUTION CREDITS?

A. Yes. Primary and substation distribution costs are generally allocated based on the cost-of-service class's share of Residential NCP. The NCP and summer average NCP are used to determine the distribution portion of the Solar Credit, as NCP alone would again essentially result in the use of solely delivered load. Secondary distribution is allocated on the sum of individual max (SIM) demands, and the use of the difference between summer average of SIM for delivered and site load are used for the calculation of the credit.

Q. WHEN ALLOCATING THE TRANSMISSION COMPONENT OF THE SOLAR CREDIT, WHY DOES APS USE A DIFFERENT COST ALLOCATION METHOD THAN WHAT IS USED IN THE COSS?

A. Transmission costs are directly allocated based on transmission revenues because transmission is regulated by the Federal Energy Regulatory Commission (FERC). FERC allocates the costs of the transmission system using the 4CP for the following classes: (i) residential; (ii) general service customers under 3 MW; and (iii) general service customers over 3 MW. For the residential share of costs, FERC allocates the costs based on their share of 4CP, and the rate is based on those costs divided by the billed kWh.

To calculate the Solar Credit, the Company uses 4CP to evaluate each DG class's share of transmission costs compared to revenues, as the credit should be adjusted for any existing over or under collection. As for the capacity side, the credit is based on the average of the difference between delivered and site 4CP alone. In

this case, the calculation essentially leaves the allocation at a level for delivered load, which is appropriate as transmission is regulated by FERC. Finally, due to net metering, the Legacy DG classes are typically under-billed for their fair share of transmission and have additional costs added beyond the calculated credit, while RCP DG customers are at a position where their under-recovered share of transmission costs are offset for the most part by the calculated credit.

Q. WHAT IS THE COMMISSION'S OPINION ON HOW THESE COMPONENTS OF THE SOLAR CREDIT ARE CALCULATED?

A. The Commission ordered in Decision No. 79293 that APS should calculate the production demand, transmission, and distribution components of the Solar Credit in the manner described above.[41]

Q. DO YOU CONCUR THAT APS SHOULD BASE THE SOLAR CREDIT VALUE OF SOLAR PRODUCTION ON MARGINAL ENERGY COSTS, RATHER THAN BASE FUEL COSTS?

A. No. This issue was fully litigated in APS's 2022 Rate Case and then addressed again during the 2022 Rate Case Rehearing process. The same value was used for both the site load and delivered load COSSs to accurately reflect the value of DG-produced energy for APS's system. The base fuel rate reflects the average cost per kWh of the overall cost of fuel and purchase power during the Test Year. Since the base fuel rate represents the overall average cost of energy, not a maximum or minimum value, it more appropriately reflects the costs of fuel and purchase power for the year, including line losses, and thus the average savings that occur if energy did not need to be produced.

[41] Decision No. 79293 at 448.

Q. IS ARISEIA'S PROPOSED AVOIDED ENERGY COST (AEC) RATE APPROPRIATE?

A. No. AriSEIA witness Kevin Lucas is proposing an AEC of $0.10468/kWh, based on his own calculation of the average marginal wholesale cost.[42] Please see Mr. Walter's Rebuttal Testimony for a discussion of why crediting DG based on the average marginal cost of purchased power from the wholesale market is inappropriate.

Q. IS IT WRONG TO TAKE THE RCP AND EPR-6 PAYMENTS TO DG CUSTOMERS INTO ACCOUNT WHEN DETERMINING THEIR COST OF SERVICE?

A. No. The energy exports and related compensation are an important component in the consideration of the solar classes' cost of service. The compensation received by solar customers is a cost that is paid by all customers through the PSA. Because of this, it is important to recognize it in the COSS as part of the valuation in the Solar Credit.

Q. WHAT IS THE COMMISSION'S OPINION ON THE SOLAR CREDIT BEING OFFSET BY THE EXPORT PAYMENTS?

A. In Decision No. 79293, the Commission authorized APS to count the amounts paid to DG customers for their exported energy against their calculated Solar Credits.[43] Including the RCP and EPR-6 payments provides the proper demonstration of how exports are being compensated versus the value they are bringing to the system. If the value that solar brings to the system ever increases to a point where it is higher than the RCP compensation rate, it would result in a benefit to the residential DG customers' cost of service.

[42] Lucas Direct at 38.
[43] Decision No. 79293 at 448.

Q. HOW DID THE RESIDENTIAL DG REPLACEMENT STUDY INFORM APS'S CALCULATION OF THE SOLAR CREDIT?

A. As discussed in my Direct Testimony, APS was ordered by the Commission to conduct a hypothetical comparative analysis of what the Company's system would have looked like in the absence of residential DG, particularly focusing on production costs.[44] As discussed further by Mr. Walter, the study examined the cost of replacing DG from both market purchases and utility-scale solar. For the 2024 TY, APS provided $126.1 million (updated for this Rebuttal Testimony) worth of Solar Credits to DG customers. To replace that same energy with market purchases would have cost $54.9 million. On the other hand, to replace that same energy with utility-scale solar, based on nameplate capacity of the same output as the peak of DG generation during the Test Year, would have cost $71.6 million. These bookend values demonstrate that APS's Solar Credit to DG customers is more than fair. Mr. Walter addresses certain intervenor arguments concerning APS's DG replacement study in his Rebuttal Testimony.

Q. DO YOU HAVE COMMENTS ON ARISEIA'S SOLAR COSS?

A. Yes. When looking at the Solar Credits and the proposals from AriSEIA, it is valuable to take a step back from the granular level and look from a more high-level approach to see if the numbers make sense overall. Figure 12 below compares the COSS solar classes' current operating revenues, APS's revenue requirement (as provided in its initial Application in this proceeding), the delivered load revenue requirement submitted by AriSEIA, the related percentage reduction, and number of customers for each cost of service class.

[44] *Id.* at 448.

Figure 12. AriSEIA COSS Solar Classes Comparison

COSS Class	APS Application Rev. Req.	Kevin Lucas WP 13 Delivered Load Rev. Req.	% Reduction from APS Proposed Application	Customers
Legacy Solar (Energy)	$ 203,420,884	$ 95,097,017	53%	71,210
Legacy Solar (Demand)	$ 5,019,170	$ 2,738,649	45%	1,409
R-Solar (TOU)	$ 240,889,819	$ 9,938,460	96%	77,248
R-Solar (Demand)	$ 84,523,405	$ 11,131,751	87%	25,742

AriSEIA's recommended Delivered Load COSS would reduce the revenue requirement for residential DG customers by 53% to 96% compared to APS's proposal. These reductions are extreme and unreasonable and do not accurately reflect the costs to serve these customers. The percentage change between site and delivered MWh and 4CP would not support the reduction, as shown in Figure 13

Figure 13. Solar Class Basic Load Information

COSS Class	Site Annual MWH	Delivered Annual MWH	% Change between Site and Delivered Annual MWH	4 CP Site	4 CP Delivered	% Change between Site and Delivered 4CP
Legacy Solar (Energy)	1,305,760	899,956	-31%	383	309	-19%
Legacy Solar (Demand)	37,782	28,034	-26%	10	9	-15%
R-Solar (TOU)	1,181,714	737,975	-38%	341	240	-30%
R-Solar (Demand)	474,875	306,042	-36%	123	88	-29%

Second, AriSEIA's proposed revenue requirement for R-Solar (TOU), when broken out to a monthly base bill, would be $10.72, less than the current basic service charge of $13.74 for a 30-day bill.

Third, there are logical contradictions when comparing the classes within AriSEIA's study. The Legacy Solar Energy class's revenue requirement is almost 10-times the revenue requirement of the R-Solar (TOU) class despite their site

and delivered MWhs and 4CP being much more similar, which is shown in Figure 14.

Figure 14. AriSEIA COSS Legacy Solar (Energy) vs R-Solar (TOU) Comparison

COSS Class	Kevin Lucas WP 13 Delivered Load Rev. Req.	Customers	Site Annual MWH	Delivered Annual MWH	4 CP Site	4 CP Delivered
Legacy Solar (Energy)	$ 95,097,017	71,210	1,305,760	899,956	383	309
R-Solar (TOU)	$ 9,938,460	77,248	1,181,714	737,975	341	240
Difference	10%	108%	91%	82%	89%	78%

When comparing R-Solar (TOU) with R-Solar (Demand), another oddity stands out. R-Solar (Demand) has a higher revenue requirement, despite having significantly lower site and delivered MWh and 4CP as shown in Figure 15.

Figure 15. AriSEIA COSS R-Solar (TOU)vs. R-Solar (Demand) Comparison

COSS Class	Kevin Lucas WP 13 Delivered Load Rev. Req.	Customers	Site Annual MWH	Delivered Annual MWH	4 CP Site	4 CP Delivered
R-Solar (TOU)	$ 9,938,460	77,248	1,181,714	737,975	341	240
R-Solar (Demand)	$ 11,131,751	25,742	474,875	306,042	123	88
Difference	112%	33%	40%	41%	36%	37%

Bringing in other cost of service classes illuminates the illogic of AriSEIA's Delivered Load COSS. Figure 16 shows the revenue requirements and basic load information for R-Solar (TOU) and R-Solar (Demand) as well as Street Lighting and Dusk to Dawn for further comparison. AriSEIA's recommended revenue requirement would be significantly below the streetlighting classes, despite substantially higher site and delivered MWhs and 4CP .

Figure 16. AriSEIA COSS R-Solar Classes vs. Streetlighting Comparison

COSS Class	Kevin Lucas WP 13 Delivered Load Rev. Req.	Site Annual MWH	Delivered Annual MWH	4 CP Site	4 CP Delivered
R-Solar (TOU)	$ 9,938,460	1181714	737,975	341	240
R-Solar (Demand)	$ 11,131,751	474875	306,042	123	88
Street Lighting	$ 20,270,408	105,467	105,467	1	1
Dusk to Dawn	$ 14,794,770	17,485	17,485	-	-

Q. IF THE COMMISSION ADOPTS ARISEIA'S COSS, DO YOU AGREE WITH ARISEIA THAT THERE WOULD NOT BE A COST SHIFT TO OTHER CUSTOMERS?

A. No. AriSEIA's proposed COSS would shift between $415 million and $449 million from DG customers to every other customer class and subclass. As Mr. Lucas describes, AriSEIA's proposed COSS would reduce the revenue requirement of the four residential DG subclasses from $533.9 million to $118.9 million, if the load measurement is reduced from site to delivered.[45] If the load measurement is reduced from site to net, the revenue requirement falls to $85.2 million.[46] Mr. Lucas asserts that these changes are "not a 'cost shift' to non-solar or non-residential customers."[47] The only way Mr. Lucas can argue that a revenue requirement reduction of over $400 million to four subclasses is *not* a cost shift to all other classes is by rejecting APS's Site Load COSS and the Company's calculations for the Value of Solar and Solar Credit. All of which were approved by the Commission—twice over—as recently as 2024.

Q. DO YOU HAVE ANY FINAL COMMENTS ON ARISEIA'S COSS?

A. The Commission should reject AriSEIA's COSS.

[45] Lucas Direct at 43.
[46] *Id.* at 43.
[47] *Id.* at 43-44.

XII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

Yes.

ARIZONA PUBLIC SERVICE COMPANY
STANDARD FILING REQUIREMENT SCHEDULE A-1
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2024
(Thousands of Dollars)

Line No.	Description	Electric Original Cost	Electric RCND	Electric Fair Value	Line No.
1.	Rate Base	$ 13,064,062 (a)	$ 31,297,360 (a)	$ 22,180,711	1.
2.	Operating Income	559,130 (b)	559,130 (b)	559,130 (b)	2.
3.	Current Rate of Return	4.28%	1.79%	2.52%	3.
4.	Required Operating Income	996,788	996,788	996,788	4.
5.	Required Rate of Return on OCRB	7.63% (d)	3.18% *	4.49% *	5.
6.	Operating Income Deficiency on OCRB	437,658	437,658	437,658	6.
7.	Gross Revenue Conversion Factor	1.3358 (c)	1.3358 (c)	1.3358 (c)	7.
8.	Increase in Base Revenue Requirements Based on OCRB	$ 584,625 **	$ 584,625 **	$ 584,625 **	8.
9.	After Tax Return on Fair Value Increment			109,602	9.
10.	Requested Increase in Base Revenue Requirements			$ 694,227	10.
11.	Required Rate of Return with Fair Value Increment			4.86%	11.

	Customer Classification	Projected Revenue Increase Due to Base Rates	Base Rate % Increase	Adjustor Transfer Net Bill Impact % Increase	
12.	Residential	$ 370,828	17.23%	15.36%	12.
13.	General Service	312,335	16.23%	14.10%	13.
14.	Irrigation and Water Pumping	6,085	16.73%	11.88%	14.
15.	Outdoor Lighting	3,421	16.75%	16.25%	15.
16.	Dusk-to-Dawn	1,558	16.76%	16.57%	16.
17.	Total	694,227	16.76%	14.75%	17.
18.	Total Sales to Ultimate Retail Customers	$ 4,143,229 (e)			18.

Notes:
* The Rate of Return for OCRB, RCND and Fair Value does not reflect the need for a return on the difference between Fair Value Rate Base and Original Cost Rate Base but is simply a mathematical derivation based upon the original cost rate of return.
** Does not include the fair value increment reflected on Line 9.

Supporting Schedules:
(a) B-1
(b) C-1, page 2 of 2
(c) C-3
(d) D-1
(e) H-1

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

Calculation of Fair Value Increment

(Thousands of Dollars)

Calculation of Fair Value Increment

	Adjusted Test Year Capital Structure	Amount	%	Cost Rate	Weighted Avg
1.	Long-Term Debt	$ 7,543,975	47.65%	4.26%	2.03%
2.	Preferred Stock	-	0.00%	0.00%	0.00%
3.	Common Equity	8,287,281	52.35%	10.70%	5.60%
4.	Short-Term Debt	-	0.00%	0.00%	0.00%
5.	Total	$ 15,831,256	100.00%		7.63%

	Capital Structure with 0.90% FV Increment	Amount	%	Cost Rate	Weighted Avg
6.	Long-Term Debt	$ 6,225,340	28.07%	4.26%	1.20%
7.	Preferred Stock	-	0.00%	0.00%	0.00%
8.	Common Equity	6,838,722	30.83%	10.70%	3.30%
9.	Short-Term Debt	-	0.00%	0.00%	0.00%
10.	FVRB Increment	9,116,649	41.10%	0.90%	0.37%
11.	Total	$ 22,180,711	100.00%		4.86%

	Fair Value Increment Calculation	Fair Value	Original Cost
12.	Rate Base	$ 22,180,711	$ 13,064,062
13.	Rate of Return	4.86%	7.63%
14.	Required Operating Income	$ 1,078,993	$ 996,943
15.	Adjusted Operating Income	559,130	$ 559,130
16.	Adjusted Operating Income Deficiency (line 14 - line 15)	$ 519,862	$ 437,812
17.	Revenue Conversion Factor	1.3358	1.3358
18.	Increase in Base Revenue Requirements (line 16 * line 17)	$ 694,434	$ 584,831
19.	Fair Value Increment	$ 109,602.479	
	RCND Rate Base	$ 31,297,360	

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2024 Test Year Adjusted Cost of Service Study

SUMMARY OF RESULTS	ELECTRIC TOTAL	ALL OTHER	ACC JURISDICTION	RETAIL					
				RESIDENTIAL	GENERAL SERVICE	E-221 NonAG	E-221 AG	Street Lighting	Dusk to Dawn
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 11,407,456,735	$ 9,881,014	$ 11,397,575,721	$ 6,263,354,419	$ 5,035,192,113	$ 77,630,414	$ 118,080	$ 18,365,707	$ 2,914,989
TRANSMISSION PLANT IN SERVICE	3,986,340,920	3,986,340,920	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	9,019,398,608	36,142	9,019,362,465	6,695,015,469	2,060,422,133	42,980,195	125,567	115,440,212	105,378,890
GENERAL & INTANGIBLE PLANT	3,123,456,800	278,055,156	2,845,401,644	1,868,673,147	951,651,603	15,628,591	43,926	5,421,537	3,982,841
LESS: RESERVE FOR DEPRECIATION	(10,037,959,209)	(1,264,790,898)	(8,773,168,311)	(5,482,253,696)	(3,164,544,845)	(52,078,560)	(105,997)	(41,864,758)	(32,320,456)
MATERIALS, SUPPLIES & PREPAYMENTS	659,665,129	75,448,049	584,217,080	350,455,636	224,925,112	3,860,463	8,252	2,917,142	2,050,476
MISCELLANEOUS DEFERRED DEBITS	27,471,000	1,667,893	25,803,107	15,278,198	10,262,217	176,715	448	60,290	25,239
OTHER DEFERRED CREDITS	(1,717,699,266)	(21,484,063)	(1,696,215,203)	(940,002,173)	(740,596,772)	(11,653,155)	(19,534)	(3,155,947)	(787,622)
OPEB	335,458,444	30,988,471	304,469,973	197,486,286	104,282,332	1,721,642	4,791	591,102	383,820
WORKING CASH	(175,589,220)	(33,380,934)	(142,208,286)	(93,145,380)	(46,393,580)	(774,267)	(1,473)	(1,022,406)	(871,180)
REGULATORY ASSETS	(294,943,411)	77,262,787	(372,206,198)	(232,611,146)	(130,333,576)	(1,985,176)	(520)	(3,893,945)	(3,381,834)
ACCUM. DEFERRED TAXES	(2,448,228,991)	(416,683,485)	(2,031,545,506)	(1,310,375,446)	(685,920,799)	(11,605,221)	(24,274)	(12,954,006)	(10,665,760)
OPERATING LEASES	(30,477,627)	4,569,609	(35,047,236)	(10,042,913)	(24,385,514)	(471,573)	(967)	(162,592)	16,323
DECOMMISSIONING FUND	1,657,000,038	1,491,300	1,655,508,738	913,460,044	727,921,764	11,132,845	16,472	2,570,971	406,643
CUSTOMER ADVANCES	(569,343,441)	(38,254,375)	(531,089,066)	(50,613,987)	(479,062,967)	(130,332)	(293)	(1,281,187)	(300)
CUSTOMER DEPOSITS	(42,198,184)	-	(42,198,184)	(9,118,941)	(31,961,976)	(608,124)	(1,401)	(351,644)	(156,098)
PROFORMA ADJUSTMENTS	942,732,137	87,330,928	855,401,209	462,881,335	384,956,128	5,890,103	8,202	1,436,270	229,171
TOTAL RATE BASE	**15,842,540,463**	**2,778,478,515**	**13,064,061,948**	**8,638,440,851**	**4,196,413,372**	**79,714,558**	**171,279**	**82,116,746**	**67,205,142**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	4,232,605,779	78,057,643	4,154,548,136	2,201,721,531	1,886,868,982	35,900,474	82,699	20,759,219	9,215,231
PRO FORMA TO BASE REVENUES FROM RATES	(11,318,921)	-	(11,318,921)	(49,494,072)	38,057,897	355,566	24,227	(342,002)	79,463
SURCHARGE & OTHER ELECTRIC REVENUES	910,744,221	49,917,692	860,826,530	428,400,073	419,621,971	9,903,777	25,154	2,302,467	573,088
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(729,683,904)	(734,708)	(728,949,196)	(360,586,606)	(357,249,563)	(8,742,782)	(22,231)	(1,867,294)	(480,720)
TOTAL OPERATING REVENUES	**4,402,347,175**	**127,240,626**	**4,275,106,548**	**2,220,040,927**	**1,987,299,286**	**37,417,035**	**109,849**	**20,852,390**	**9,387,062**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,709,315,376	(194,851,516)	2,904,166,892	1,520,636,013	1,349,224,389	25,310,030	65,629	6,828,975	2,101,857
ADMINISTRATIVE & GENERAL	225,590,531	25,902,597	199,687,934	128,817,325	69,056,017	1,137,265	3,083	408,552	265,692
DEPRECIATION & AMORT EXPENSE	850,735,052	102,065,600	748,669,452	475,573,458	262,061,359	4,374,502	9,584	3,722,810	2,927,739
OTHER EXPENSE ITEMS	43,154,099	54,614	43,099,485	21,689,006	20,897,375	370,671	813	121,560	20,059
TAXES OTHER THAN INCOME	258,912,678	41,746,984	217,165,694	145,264,927	67,785,909	1,190,143	2,829	1,575,934	1,345,953
PROFORMA ADJUSTMENTS	(390,338,910)	6,171,709	(396,510,620)	(199,724,988)	(192,016,300)	(4,694,689)	(2,130)	(423,251)	350,739
INCOME TAX	136,678,000	18,516,661	118,161,339	79,127,029	36,889,131	714,509	1,578	780,865	648,226
PROFORMA INCOME TAX ADJUSTMENTS	(120,309,160)	(1,845,005)	(118,464,156)	(64,104,242)	(53,312,413)	(815,718)	(1,136)	(198,908)	(31,738)
TOTAL OPERATING EXPENSES	**3,713,737,666**	**(2,238,355)**	**3,715,976,021**	**2,107,278,528**	**1,560,585,467**	**27,586,712**	**80,250**	**12,816,537**	**7,628,527**
OPERATING INCOME	**688,609,508**	**129,478,981**	**559,130,527**	**112,762,398**	**426,713,819**	**9,830,323**	**29,600**	**8,035,853**	**1,758,535**
RATE OF RETURN (PRESENT)	**4.35%**	**4.66%**	**4.28%**	**1.31%**	**10.17%**	**12.33%**	**17.28%**	**9.79%**	**2.62%**
INDEX RATE OF RETURN (PRESENT)	-	-	**1.0**	**0.3**	**2.4**	**2.9**	**4.0**	**2.3**	**0.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**5,025,742,791**	**188,286,732**	**4,837,456,058**	**2,955,535,694**	**1,816,786,149**	**31,900,488**	**86,234**	**18,760,469**	**14,387,024**
% OF TOTAL COST OF SERVICE (PRESENT)	**85.66%**	**41.46%**	**87.38%**	**74.19%**	**108.22%**	**119.19%**	**128.24%**	**109.36%**	**64.73%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**97.81%**	**41.46%**	**100.00%**	**85.37%**	**123.14%**	**132.70%**	**135.38%**	**127.06%**	**75.43%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2024 Test Year Adjusted Cost of Service Study

SUMMARY OF RESULTS	RESIDENTIAL								
	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar TOU	R-Solar (Demand)	R-Basic (0-600kW)	R-Basic (601-999 kW)	R-Basic (1000+ kW)	R-TOU	R-Demand
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 500,510,537	$ 13,698,007	$ 448,894,142	$ 170,947,784	$ 599,198,640	$ 530,108,621	$ 402,582,756	$ 1,303,897,975	$ 2,293,515,958
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	461,286,582	11,137,620	460,733,639	166,845,588	1,043,588,348	645,467,557	369,860,670	1,354,833,001	2,181,262,465
GENERAL & INTANGIBLE PLANT	128,389,094	3,184,859	124,001,183	45,107,540	288,899,998	179,450,169	106,253,016	376,039,154	617,348,133
LESS: RESERVE FOR DEPRECIATION	(405,959,154)	(10,501,759)	(382,012,128)	(141,753,953)	(698,856,492)	(498,233,012)	(327,807,184)	(1,123,310,743)	(1,893,819,271)
MATERIALS, SUPPLIES & PREPAYMENTS	26,181,913	691,473	24,522,148	9,237,185	42,680,728	31,267,092	21,210,406	71,850,925	122,813,768
MISCELLANEOUS DEFERRED DEBITS	1,101,184	28,945	1,037,474	390,586	2,037,475	1,391,472	910,053	3,100,249	5,280,761
OTHER DEFERRED CREDITS	(74,071,250)	(2,019,330)	(66,897,167)	(25,469,783)	(94,750,123)	(80,316,521)	(59,800,059)	(194,964,382)	(341,713,559)
OPEB	13,686,175	342,125	13,156,757	4,803,385	29,831,393	18,827,468	11,316,515	39,830,920	65,691,549
WORKING CASH	(6,896,178)	(175,778)	(6,547,913)	(2,410,353)	(12,039,788)	(8,527,841)	(5,511,983)	(19,124,593)	(31,910,953)
REGULATORY ASSETS	(19,292,211)	(512,195)	(17,608,872)	(6,572,030)	(20,286,600)	(19,613,812)	(14,828,259)	(49,233,380)	(84,663,786)
ACCUM. DEFERRED TAXES	(96,246,455)	(2,462,605)	(91,435,903)	(33,778,383)	(171,845,225)	(120,113,726)	(77,428,230)	(268,284,588)	(448,780,330)
OPERATING LEASES	(1,048,048)	(38,488)	(831,689)	(407,495)	767,523	(399,341)	(867,912)	(2,176,169)	(5,041,295)
DECOMMISSIONING FUND	73,052,807	1,995,418	65,498,838	24,895,912	87,444,717	77,416,074	58,702,532	190,249,736	334,204,009
CUSTOMER ADVANCES	(1,727,344)	(79,130)	(2,829,144)	(1,050,791)	(5,474,392)	(4,783,095)	(3,983,123)	(11,991,028)	(18,695,940)
CUSTOMER DEPOSITS	(305,577)	(14,180)	(507,775)	(188,520)	(987,829)	(862,951)	(719,398)	(2,163,899)	(3,368,813)
PROFORMA ADJUSTMENTS	37,610,372	1,037,508	33,489,283	12,801,729	41,140,077	38,590,647	30,135,931	96,759,229	171,316,558
TOTAL RATE BASE	**636,272,447**	**16,312,488**	**602,662,872**	**223,398,402**	**1,131,348,449**	**789,668,801**	**510,025,731**	**1,765,312,406**	**2,963,439,255**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	73,780,020	3,423,733	122,599,623	45,517,080	238,506,176	208,355,117	173,694,963	522,462,294	813,382,525
PRO FORMA TO BASE REVENUES FROM RATES	(3,755,615)	(63,964)	(234,635)	3,872,507	(4,502,029)	(1,834,502)	1,086,963	(43,277,083)	(785,715)
SURCHARGE & OTHER ELECTRIC REVENUES	17,892,519	662,464	23,018,185	9,196,150	47,371,282	38,782,719	29,438,198	94,228,957	167,809,599
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(12,582,676)	(510,271)	(18,205,269)	(7,267,504)	(40,986,100)	(33,251,277)	(25,106,199)	(80,264,419)	(142,412,889)
TOTAL OPERATING REVENUES	**75,334,247**	**3,511,962**	**127,177,904**	**51,318,233**	**240,389,328**	**212,052,057**	**179,113,925**	**493,149,749**	**837,993,521**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	67,000,976	2,150,694	117,893,621	40,538,275	175,190,935	134,438,237	97,252,474	318,860,612	567,310,189
ADMINISTRATIVE & GENERAL	8,982,344	225,409	8,612,186	3,149,491	19,177,717	12,227,396	7,414,491	26,016,627	43,011,664
DEPRECIATION & AMORT EXPENSE	34,735,783	890,859	32,919,278	12,172,116	63,068,982	43,684,210	28,121,804	97,160,083	162,820,343
OTHER EXPENSE ITEMS	1,702,268	48,688	1,537,616	611,077	2,044,527	1,779,628	1,399,976	4,468,472	8,096,754
TAXES OTHER THAN INCOME	10,403,112	261,466	10,031,052	3,680,333	20,439,920	13,578,228	8,395,569	29,582,861	48,892,386
PROFORMA ADJUSTMENTS	(834,746)	(168,645)	(6,164,605)	(1,369,479)	(23,776,868)	(18,637,386)	(13,330,728)	(53,994,864)	(81,447,667)
INCOME TAX	5,794,142	147,839	5,508,738	2,038,257	10,551,565	7,269,299	4,644,606	16,149,067	27,023,517
PROFORMA INCOME TAX ADJUSTMENTS	(5,208,645)	(143,684)	(4,637,917)	(1,772,906)	(5,697,472)	(5,344,403)	(4,173,513)	(13,400,145)	(23,725,559)
TOTAL OPERATING EXPENSES	**122,575,235**	**3,412,624**	**165,699,970**	**59,047,164**	**260,999,306**	**188,995,209**	**129,724,680**	**424,842,712**	**751,981,628**
OPERATING INCOME	**(47,240,987)**	**99,338**	**(38,522,066)**	**(7,728,931)**	**(20,609,978)**	**23,056,848**	**49,389,245**	**68,307,037**	**86,011,893**
RATE OF RETURN (PRESENT)	**-7.42%**	**0.61%**	**-6.39%**	**-3.46%**	**-1.82%**	**2.92%**	**9.68%**	**3.87%**	**2.90%**
INDEX RATE OF RETURN (PRESENT)	**(1.7)**	**0.1**	**(1.5)**	**(0.8)**	**(0.4)**	**0.7**	**2.3**	**0.9**	**0.7**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**203,378,977**	**5,027,347**	**240,371,783**	**84,376,091**	**386,578,961**	**262,953,523**	**165,112,812**	**582,879,301**	**1,024,856,898**
% OF TOTAL COST OF SERVICE (PRESENT)	**35.08%**	**68.31%**	**51.73%**	**59.65%**	**61.62%**	**79.90%**	**107.59%**	**83.76%**	**80.89%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**41.64%**	**79.57%**	**60.71%**	**69.81%**	**72.20%**	**91.70%**	**121.82%**	**95.97%**	**92.58%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2024 Test Year Adjusted Cost of Service Study

SUMMARY OF RESULTS	GENERAL SERVICE								
	E-20 (Church Rate)	E-32 TOU (0-20 kW)	E-32 TOU (21-100 kW)	E-32 TOU (101-400 kW)	E-32 TOU (401+ kW)	School TOU	E-30, E-32 (0-20 kW)	E-32 (21-100 kW)	E-32 (101-400 kW)
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 12,260,255	$ 7,203,943	$ 8,504,141	$ 32,853,146	$ 96,586,252	$ 76,518,461	$ 527,012,412	$ 825,657,217	$ 991,760,538
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	11,239,680	4,963,749	4,133,493	12,249,934	36,334,999	44,541,508	584,884,644	428,193,207	404,829,708
GENERAL & INTANGIBLE PLANT	2,784,462	1,654,622	1,694,803	5,691,186	16,530,124	13,812,138	163,056,513	171,608,676	173,157,350
LESS: RESERVE FOR DEPRECIATION	(9,677,670)	(5,239,174)	(5,564,832)	(19,997,274)	(58,677,006)	(51,304,599)	(469,152,675)	(552,568,544)	(614,110,300)
MATERIALS, SUPPLIES & PREPAYMENTS	642,398	368,243	395,395	1,449,170	4,310,599	3,594,140	31,026,936	38,338,606	44,218,876
MISCELLANEOUS DEFERRED DEBITS	25,975	16,605	18,028	65,136	193,886	149,660	1,391,504	1,742,215	1,961,697
OTHER DEFERRED CREDITS	(1,811,035)	(1,079,706)	(1,257,976)	(4,822,989)	(14,219,804)	(11,215,880)	(80,378,670)	(121,814,555)	(145,551,722)
OPEB	305,739	178,134	186,530	628,992	1,828,683	1,526,304	17,199,531	18,860,708	19,132,216
WORKING CASH	(167,538)	(81,451)	(83,180)	(291,546)	(851,439)	(822,627)	(7,816,943)	(8,402,980)	(9,116,742)
REGULATORY ASSETS	(504,208)	(207,968)	(225,127)	(866,934)	(2,519,131)	(2,627,819)	(17,884,921)	(22,696,492)	(27,500,477)
ACCUM. DEFERRED TAXES	(2,325,667)	(1,191,881)	(1,227,239)	(4,315,332)	(12,667,020)	(11,696,288)	(111,945,643)	(122,769,075)	(133,884,270)
OPERATING LEASES	(35,374)	(33,950)	(40,888)	(175,270)	(550,071)	(350,605)	(1,437,099)	(3,418,350)	(5,157,388)
DECOMMISSIONING FUND	1,785,297	1,038,706	1,228,397	4,742,805	13,918,315	11,085,013	76,318,365	119,612,489	143,263,378
CUSTOMER ADVANCES	(704,148)	(627,102)	(659,283)	(2,191,378)	(5,907,177)	(4,454,349)	(45,868,774)	(58,980,477)	(63,928,300)
CUSTOMER DEPOSITS	(74,839)	(66,693)	(70,105)	(232,969)	(627,913)	(473,436)	(4,878,187)	(6,270,944)	(6,795,940)
PROFORMA ADJUSTMENTS	929,779	542,906	647,180	2,525,926	7,427,886	5,888,970	38,661,792	62,688,891	76,262,467
TOTAL RATE BASE	**14,673,105**	**7,438,984**	**7,679,337**	**27,312,602**	**81,111,181**	**74,170,591**	**700,188,785**	**769,780,594**	**848,541,091**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	4,418,087	3,937,224	4,138,637	13,753,285	37,068,722	27,949,200	287,982,783	370,203,932	401,196,979
PRO FORMA TO BASE REVENUES FROM RATES	(60,341)	(228,981)	94,637	924,675	3,733,074	1,131,755	3,770,891	2,808,329	4,918,106
SURCHARGE & OTHER ELECTRIC REVENUES	1,102,667	833,311	863,515	2,990,077	7,666,034	6,510,730	58,049,946	83,699,906	90,600,560
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(962,634)	(738,862)	(754,820)	(2,570,509)	(6,399,130)	(5,569,709)	(51,532,890)	(73,689,579)	(78,044,009)
TOTAL OPERATING REVENUES	**4,497,778**	**3,802,692**	**4,341,968**	**15,097,529**	**42,068,700**	**30,021,976**	**298,270,730**	**383,022,588**	**418,671,637**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	3,308,605	2,153,957	2,311,308	8,408,783	24,866,587	20,490,330	157,738,293	224,700,633	256,294,055
ADMINISTRATIVE & GENERAL	201,770	117,152	123,212	418,489	1,217,605	1,016,792	11,200,939	12,434,691	12,731,664
DEPRECIATION & AMORT EXPENSE	825,660	443,979	465,243	1,643,047	4,818,728	4,260,416	40,879,683	46,398,869	50,556,281
OTHER EXPENSE ITEMS	43,945	31,378	35,844	139,945	425,039	305,183	2,117,239	3,292,008	4,176,607
TAXES OTHER THAN INCOME	249,246	125,511	123,880	419,443	1,231,700	1,183,028	12,525,191	12,496,784	13,114,961
PROFORMA ADJUSTMENTS	(500,836)	(558,973)	(437,555)	(1,122,799)	(2,259,191)	(2,202,755)	(29,943,396)	(44,213,235)	(42,266,280)
INCOME TAX	133,015	66,744	68,061	239,897	713,143	660,863	6,402,579	6,843,576	7,474,487
PROFORMA INCOME TAX ADJUSTMENTS	(128,765)	(75,187)	(89,628)	(349,814)	(1,028,685)	(815,561)	(5,354,255)	(8,681,758)	(10,561,557)
TOTAL OPERATING EXPENSES	**4,132,640**	**2,304,562**	**2,600,366**	**9,796,991**	**29,984,924**	**24,898,296**	**195,566,274**	**253,271,569**	**291,520,219**
OPERATING INCOME	**365,139**	**1,498,130**	**1,741,603**	**5,300,538**	**12,083,776**	**5,123,680**	**102,704,456**	**129,751,019**	**127,151,418**
RATE OF RETURN (PRESENT)	**2.49%**	**20.14%**	**22.68%**	**19.41%**	**14.90%**	**6.91%**	**14.67%**	**16.86%**	**14.98%**
INDEX RATE OF RETURN (PRESENT)	**0.6**	**4.7**	**5.3**	**4.5**	**3.5**	**1.6**	**3.4**	**3.9**	**3.5**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**5,489,307**	**2,526,548**	**2,752,362**	**10,602,890**	**33,583,752**	**30,409,610**	**231,822,355**	**284,495,189**	**329,662,954**
% OF TOTAL COST OF SERVICE (PRESENT)	**82.74%**	**149.66%**	**157.41%**	**142.13%**	**122.61%**	**99.31%**	**128.96%**	**134.83%**	**126.80%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**92.69%**	**160.30%**	**167.99%**	**151.19%**	**141.85%**	**110.05%**	**137.44%**	**143.20%**	**134.55%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2024 Test Year Adjusted Cost of Service Study

SUMMARY OF RESULTS	GENERAL SERVICE E-32 (401+ kW)	E-34	E-35	XHLF	AG-X GSP RA	AG-X APS RA
DEVELOPMENT OF RATE BASE						
PRODUCTION PLANT IN SERVICE	$ 824,706,098	$ 307,398,161	$ 573,938,939	$ 559,990,686	$ -	$ 190,801,863
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	287,208,874	73,088,267	88,061,680	62,462,101	-	18,230,289
GENERAL & INTANGIBLE PLANT	140,224,407	49,777,327	91,374,318	89,348,357	-	30,937,319
LESS: RESERVE FOR DEPRECIATION	(494,282,511)	(174,389,624)	(311,833,735)	(297,399,925)	-	(100,346,976)
MATERIALS, SUPPLIES & PREPAYMENTS	36,410,224	12,429,117	22,285,832	21,774,042	-	7,681,533
MISCELLANEOUS DEFERRED DEBITS	1,652,108	565,880	1,044,626	1,051,739	-	383,158
OTHER DEFERRED CREDITS	(121,359,623)	(44,582,191)	(83,040,081)	(81,410,767)	-	(28,051,772)
OPEB	15,512,417	5,507,158	10,108,396	9,884,784	-	3,422,741
WORKING CASH	(7,077,690)	(2,452,249)	(4,190,977)	(3,817,989)	-	(1,220,228)
REGULATORY ASSETS	(20,773,427)	(7,657,578)	(12,833,866)	(10,960,292)	-	(3,075,337)
ACCUM. DEFERRED TAXES	(105,840,205)	(36,353,326)	(63,106,185)	(58,988,883)	-	(19,609,783)
OPERATING LEASES	(4,730,753)	(1,484,638)	(2,774,310)	(2,988,145)	-	(1,208,672)
DECOMMISSIONING FUND	118,827,407	44,546,598	83,191,455	80,942,874	-	27,420,664
CUSTOMER ADVANCES	(48,165,547)	(22,425,668)	(106,626,009)	(108,582,866)	-	(9,941,889)
CUSTOMER DEPOSITS	(5,119,416)	(1,517,989)	(2,546,042)	(2,231,028)	-	(1,056,476)
PROFORMA ADJUSTMENTS	63,428,122	23,750,189	44,350,831	43,190,736	-	14,660,455
TOTAL RATE BASE	**680,620,484**	**226,199,432**	**327,404,872**	**302,265,425**	**-**	**129,026,889**
DEVELOPMENT OF RETURN						
BASE REVENUES FROM RATES	302,223,726	89,614,192	150,305,068	131,708,306	-	62,368,841
PRO FORMA TO BASE REVENUES FROM RATES	(2,256,280)	7,522,639	11,364,091	3,437,022	-	898,280
SURCHARGE & OTHER ELECTRIC REVENUES	64,946,240	19,953,014	39,858,459	38,362,245	-	4,185,268
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(54,061,386)	(16,360,151)	(33,273,145)	(31,679,245)	-	(1,613,495)
TOTAL OPERATING REVENUES	**310,852,299**	**100,729,694**	**168,254,473**	**141,828,328**	**-**	**65,838,894**
OPERATING EXPENSES						
OPERATION & MAINTENANCE	211,949,891	81,056,514	153,942,062	148,836,311	-	53,167,058
ADMINISTRATIVE & GENERAL	10,327,820	3,672,801	6,738,030	6,580,711	-	2,274,339
DEPRECIATION & AMORT EXPENSE	40,519,807	14,132,459	25,111,751	23,916,111	-	8,089,325
OTHER EXPENSE ITEMS	3,637,165	1,218,090	2,263,979	2,331,227	-	879,726
TAXES OTHER THAN INCOME	10,221,775	3,379,876	5,700,927	5,262,699	-	1,750,889
PROFORMA ADJUSTMENTS	(33,408,911)	(4,889,751)	(13,772,397)	(16,141,364)	-	(298,857)
INCOME TAX	5,973,487	1,959,402	2,739,534	2,507,450	-	1,106,894
PROFORMA INCOME TAX ADJUSTMENTS	(8,784,134)	(3,289,154)	(6,142,128)	(5,981,467)	-	(2,030,320)
TOTAL OPERATING EXPENSES	**240,436,900**	**97,240,237**	**176,581,757**	**167,311,679**	**-**	**64,939,054**
OPERATING INCOME	**70,415,399**	**3,489,457**	**(8,327,284)**	**(25,483,350)**	**0**	**899,840**
RATE OF RETURN (PRESENT)	**10.35%**	**1.54%**	**-2.54%**	**-8.43%**	**0.00%**	**0.70%**
INDEX RATE OF RETURN (PRESENT)	**2.4**	**0.4**	**(0.6)**	**(2.0)**	**-**	**0.2**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**280,774,855**	**117,360,190**	**208,740,697**	**202,335,880**	**0**	**76,229,559**
% OF TOTAL COST OF SERVICE (PRESENT)	**107.96%**	**83.65%**	**78.46%**	**67.85%**	**0.00%**	**84.11%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**124.77%**	**100.00%**	**100.00%**	**100.00%**		**102.32%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

Power Supply Adjustment
Plan of Administration

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1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism (PSA) approved for Arizona Public Service Company (APS) by the Commission on June 28, 2007 in Decision No. 69663, and subsequently amended by the Commission in Decision Nos. 71448 (December 30, 2009), 73183 (May 24, 2012), 76295 (August 18, 2017), 78317 (November 9, 2021), ~~and~~ 79293 (March 5, 2024), and XXXXX (XXXX). The PSA provides for the recovery of fuel and purchased power costs and other production-related variable costs to the extent that those costs deviate from the amount recovered through APS's Base PSA Cost ($0.~~038321~~ 043881 per kWh) authorized in Decision No. ~~79293~~XXXX, on ~~March~~ XX ~~5~~XX, ~~2024~~202X.

Non-fuel production costs included in the PSA relate to environmental chemical expenses, which vary directly with power plant production. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The PSA allows for the refund or recovery of said costs that deviate from the base cost amount of $0.000744 per kWh.[1]

In addition, the PSA allows for the refund or recovery of the net margins from sales of emission allowances to the extent the actual sales margins deviate from the base cost amount of ($0.000001) per kWh,[2] and for recovery of mandated carbon emission costs when it is economical to incur those costs as discussed below.

APS shall not incur mandatory carbon emission allowance costs unless it passes those costs on to the California entities that are purchasing energy from APS. In no event shall APS incur

[1] $0.000744 per kWh is the result of the following: (2021-2022 Test Year chemical costs of $21,278,000 / 2021-2022 Test Year native load sales of 28,592,000 MWh) / 1000.
[2] ($0.000001) per kWh is the result of the following: (2015 net gains from sales of SO_2 allowances of $25,181 / 2015 test year native load sales of 27,030,686 MWh) / 1000.

California's carbon emission allowance costs when doing so is not an economical choice for APS's Arizona ratepayers.

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs and environmental chemical costs for fossil fuel production, and margins on the sales of emission allowances ("PSA Costs") to set a rate that is then reconciled to actual costs experienced.

This PSA includes a limit of $0.006 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year absent express approval of the Commission. This PSA also provides a mechanism for mid-year rate adjustment by either the Commission or the Company (only if overcollection occurs) in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

In addition to the PSA Rate described below, the PSA includes a mechanism that directly assigns Fuel and Purchased Power Cost for new growth-related generation resources procured to support APS generation resources, or through purchased power agreements (PPAs) by proportionally allocating the cost to the classes of customers creating that growth. The Fuel and Purchased Power Direct Assignment Cost is based on forecasted year-over-year growth in kWh sales and is incrementally allocated at the beginning of each PSA Year. These incremental, allocated costs are recovered through Adjustment Schedule PSA-1.

The Fuel and Purchased Power Direct Assignment Cost rate will not be included in the determination of the $0.006 per kilowatt-hour change limit in the PSA rate. The PSA limit of $0.006 per kilowatt, as described above, is applicable to the Forward Component, Historical Component, and Transition Component.

2. PSA Rate Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year's[3] PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual PSA Costs (fuel, purchased power and other allowable costs) and the recovery of those same cost elements through the combination of base rates and the Forward Component, and which provides for their recovery or refund during the next PSA Year.
3. The Transition Component, which provides for:
    a. The opportunity to seek mid-year changes in the PSA Rate in cases where variances between the anticipated recovery of fuel and purchased power and other allowable costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery/refund, should the Commission

[3] Each February 1 through January 31 period shall constitute a PSA Year.

deem such an adjustment to be appropriate or if the Company requests to make such a refund of an overcollection.

b. The tracking of balances resulting from the application of the Transition Components in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new general base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new general base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new general base rates.

On or before November 30 of each year, APS will submit a PSA Rate filing, which shall include a calculation of the three components of the proposed PSA Rate and the proposed Direct Assignment Cost rates. This filing shall be accompanied by such supporting information as Staff determines to be required.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February 1 and ends on the ensuing January 31, excluding any Fuel and Purchased Power Direct Assignment Costs. APS will submit, on or before November 30 of each year, a forecast, excluding any Fuel and Purchased Power Direct Assignment Costs for the upcoming PSA year (February 1-January 31) of its PSA Costs. It will also submit a forecast of kWh sales for the same period, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS's over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. The balance calculated as a result of these steps is then reduced by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e., February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual November 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the current PSA Year). The APS filing shall use these balances to calculate the Historical Component for the coming PSA Year.[4]

The November 30 filing's use of estimated balances for November through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1.

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

The Transition Component will be used as the method for incorporating any approved mid-year changes to the PSA rate. APS or Staff may request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate ($/kWh) imposed as part of the Transition Component. The Commission on its own motion may also change the PSA rate as described above.

Notwithstanding the preceding paragraph, APS may at any time during the PSA Year request to reduce the PSA through the Transition Component, which shall be deemed approved and become effective beginning with the first billing cycle of the month following the filing of such a request, provided APS files the request within the first 15 days of a month and Staff does not file opposition to the request.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

[4] For example, the November 30, 2008 filing would include actual balances for February through October of 2008 and estimated balances for November 2008 through January 2009.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before November 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year.

3. Calculation of the PSA Rate and the Fuel and Purchased Power Direct Assignment Costs

The PSA Rate is the sum of the three components; *i.e.,* Forward Component, Historical Component and Transition Component. The Fuel and Purchased Power Direct Assignment Costs are calculated in accordance with Decision No. XXXXX (*see* Schedule 10 to this POA). The PSA rate and the allocated Fuel and Purchased Power Direct Assignment Cost rates shall be applied to customer bills. Unless the Commission has otherwise acted on ~~a~~ new ~~PSA Rate~~rates by February 1, the proposed ~~PSA Rate~~rates shall go into effect. However, the PSA Rate may not change from the prior year's PSA Rate by more than plus or minus $0.006 per kWh without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA Rate and the allocated Fuel and Purchased Power Direct Assignment Cost rates shall be applicable to APS's retail electric rate schedules (with the exception of E-36 XL, AG-X, Direct Access service and any other rate that is exempt from the PSA) and ~~is~~ are adjusted annually. ~~-~~The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes. Fuel and Purchased Power Direct Assignment Cost rates are calculated individually for customer classes based on growth in sales.

The PSA Rate and the Fuel and Purchased Power Direct Assignment Cost rates shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. ~~It is~~ They are not prorated.

4. Filing and Procedural Deadlines

a. Annual November 30 Filing

APS shall file the PSA Rate with all Component calculations and the Fuel and Purchased Power Direct Assignment Cost rates for the PSA Year beginning on the next February 1, including all supporting data, with the Commission on or before November 30 of each year. ~~That~~ These calculations shall use a forecast of kWh sales and of PSA Costs for the coming PSA year, with all inputs and assumptions being the most current available for the Forward Component and Fuel and Purchased Power Direct Assignment Cost, where both forecast sales and forecast cost utilize the PSA year. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same

forecast of sales used for the Forward Component calculation. The Transition Component ~~filing,~~ if necessary, shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[5]

b. Annual November 30 Filing Review Process

~~The~~ Commission Staff and interested parties shall have an opportunity to review the November 30 forecast, balances and supporting data on which the calculations of the three PSA components and the Fuel and Purchased Power Direct Assignment Costs have been based. Any objections to the November 30 calculations shall be filed within 60 days of the APS filing. Unless the Commission has otherwise acted on the APS calculations by February 1, the ~~PSA~~ rates proposed by APS shall go into effect with the first February billing cycle.

c. Additional Filings and Notifications

APS shall also file with the Commission any additional information that Staff determines it requires to verify the component calculations, account balances and any other matter pertinent to the PSA.

Additionally, APS will file in both the docket in which the then-current PSA rate was approved, if applicable, and in the docket for the most recently completed general rate case notifying Commission Staff when the under-collected or over-collected PSA balance is greater than $100 million. The notice will include the current balances of the PSA and include a proposal for how the under-collection or over-collection should be addressed through the transition component with supporting calculations. Staff shall, within 60 days after the filing of such notification and proposal, review the notification and proposal, contact APS to obtain any supporting data necessary to review the calculations, and file in the docket in which the then-current PSA rate was approved, with a copy to the docket for the most recently completed general rate case, a Staff Report and Proposed Order analyzing the notification and proposal and recommending whether and in what manner the under-collection or over-collection should be addressed through the transition component of the PSA.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power and other allowable costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any

[5] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest – Interest is applied on the PSA balance annually at the following rates: any over-collection existing at the end of the PSA year will be credited an amount equal to interest at a rate equal to the Company's authorized Return on Equity ("ROE") or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the end of the PSA Year will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

Base Chemical Costs – An amount generally expressed as a rate per kWh, which reflects the non-fuel production costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The Base Chemical Costs are set at $0.000744 per kWh effective on March 8, 2024.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power costs embedded in ~~the~~ base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. ~~79293~~ XXXXX set the composite base cost at ~~$0.038321~~$0.043881 per kWh across the 4 classes (Residential, Other General Service, E-34 and E-35, and XHLF) effective on ~~March 8, 2024~~XXX, XX, 202X.

Base Fuel less New Incremental Generation - Base Cost of Fuel and Purchased Power less Base Fuel and Purchased Power Direct Assignment Costs is an amount generally expressed as a rate per kWh, which reflects the fuel and purchased power costs embedded in base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $0.042566 per kWh effective on XXX, XX, 202X.

Base Fuel and Purchased Power Direct Assignment Costs – An amount generally expressed as a rate per kWh reflecting Fuel and Purchased Power Incremental Costs approved in Decision No. XXXXX. Base Fuel and Purchased Power Direct Assignment Costs are allocated to four separate rate classes: 1) Residential - $0.000872 per kWh, 2) Other General Service - $0.000414 per kWh,[6] 3) Rate Schedules E-34 and E-35 - $0.004979 per kWh, and 4) Rate Schedule XHLF - $0.004779 per kWh.

[6] For purposes of this calculation, Other General Service includes all General Service and Classified rate schedules that are not identified as a separate class.

Fuel and Purchased Power Incremental Costs – An amount reflecting the annual fuel and purchased power cost related to forecasted new incremental generation procured to support APS generation resources, or through PPAs to serve growth. Fuel and Purchased Power Incremental Costs, are updated annually, and are used to determine the Fuel and Purchased Power Direct Assignment Costs for the upcoming PSA Year.

Fuel and Purchased Power Direct Assignment Costs – An amount generally expressed as a rate per kWh reflecting Fuel and Purchased Power Incremental Costs for the upcoming PSA Year. Fuel and Purchased Power Direct Assignment Costs are allocated to four separate rate classes based on year-over-year growth in sales: 1) Residential, 2) Other General Service,[7] 3) Rate Schedules E-34 and E-35, and 4) Rate Schedule XHLF, as calculated in Schedule 10 to this POA. These rates are updated annually on February 1 of each year and are effective with the first billing cycle in February.

Base Net Margins on the Sale of Emission Allowances - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of SO_2 emission allowances embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at ($0.000001) per kWh effective on March 8, 2024.

Base PSA Costs - A rate equal to the sum of Base Cost of Fuel and Purchased Power and Fuel and Purchased Power Direct Assignment Costs as defined above, the Base Chemical Costs, and the Base Net Margins on the Sale of Emission Allowances.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and is effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecast PSA Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS's base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis APS's over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue, plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and is effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism

[7] For purposes of this calculation, All Other General Service includes all General Service and Classified rate schedules that are not identified as a separate class.

to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest at year end. The balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mandated Carbon Emission Allowance Costs – The costs incurred in purchasing allowances to meet legal requirements, beginning in 2013, that electricity from resources which emit carbon must be accompanied by carbon emission allowances equal to the amount of carbon emitted in generating the electricity (recorded in FERC Account 509 – Allowances).

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load refers to the energy needed for customer load in the balancing authority area for which APS has a generation service obligation.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

PSA - The Power Supply Adjustment mechanism approved by the Commission.

PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus costs for environmental chemicals used in power production at fossil and nuclear production sites, storage product costs and the Net Margins on the Sales of Emission Allowances.

PSA Year - A consecutive 12-month period generally beginning each February 1.

Storage Product Costs - All costs associated with third-party storage facilities, including rent, capacity, and lease payments for electricity storage facilities (e.g., batteries) that APS utilizes in the dispatch of generated or purchased electricity.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with

applicable special contracts, E-36 XL, AG-X, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No. 78317.

System Book Off-System Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS's electricity over transmission facilities owned by others.

7. Schedules

Samples of the following schedules are attached to this Plan of Administration.

Schedule 1	PSA Rate Calculation
Schedule 2	PSA Forward Component Rate Calculation
Schedule 3	PSA Year Forward Component Tracking Account
Schedule 4	PSA Historical Component Rate Calculation
Schedule 5	Historical Component Tracking Account
Schedule 6	PSA Transition Component Rate Calculation
Schedule 7	PSA Transition Tracking Account
Schedule 8	Summary of Monthly Calculations
Schedule 9	Native Load Customer Counts, Sales and Revenue
Schedule 10	Fuel and Purchased Power Direct Assignment Cost Calculation

8. Compliance Reports

APS shall provide monthly reports to Staff and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in APS's annual report filed with the Commission's Corporations Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her

information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs
    b. Margins on the sale of excess emission allowances
    c. ——Environmental chemical costs for fossil generation
    d. Customer sales in both MWh and thousands of dollars by customer class
    e. Number of customers by customer class
    f. A detailed listing of all items excluded from the PSA calculations
    g. A detailed listing of any adjustments to the adjustor reports
    h. Total off-system sales revenues
    i. System losses in MW and MWh
    j. Monthly maximum retail demand in MW

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively
2. Average heat rate, both monthly and 12-month average
3. Equivalent forced-outage factor, both monthly and 12-month average
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description
5. Total fuel costs per month
6. The fuel cost per kWh per month

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh
2. The demand purchased in MW to the extent specified in the contract
3. The total cost for demand to the extent specified in the contract
4. The total cost of energy

C. Information on off-system sales shall include the following items:

1. An itemization of off-system sales margins per buyer
2. Details on negative off-system sales margins

D. Fuel purchase information shall include the following items:

1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm or per MCF, total cost, supply basin and volume by contract

E. APS will also provide:

1. Monthly projections for the next 12-month period showing estimated over/under-collected amounts
2. A summary of unplanned outage costs by resource type
3. A summary of the net margins on the sale of emission allowances
4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing
5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, costs for specified environmental chemicals that vary with power generated at fossil power plants, storage product costs, and the net margins on the sale of emission allowances and Mandated Carbon Emission Allowance Costs will also be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission (FERC) accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)

- 509 Allowances[8]

Additionally, broker fees recorded in FERC account 557 up to the amount included in the Base Fuel Cost and costs for environmental chemicals used in power production in FERC accounts 502 and 549 are allowable accounts.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Treatment of Directly Assignable Power Supply Costs

Decision No. 66567 (November 18, 2003) provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 XL and AG-X customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs and kWh usage are excluded from the PSA.

[8] Or any successor FERC account used to record the costs of purchasing carbon emission allowances.

Power Supply Adjustment
Plan of Administration

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1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism (PSA) approved for Arizona Public Service Company (APS) by the Commission on June 28, 2007 in Decision No. 69663, and subsequently amended by the Commission in Decision Nos. 71448 (December 30, 2009), 73183 (May 24, 2012), 76295 (August 18, 2017), 78317 (November 9, 2021), 79293 (March 5, 2024), and XXXXX (XXXX). The PSA provides for the recovery of fuel and purchased power costs and other production-related variable costs to the extent that those costs deviate from the amount recovered through APS's Base PSA Cost ($0.043881 per kWh) authorized in Decision No. XXXX, on XX XX, 202X.

Non-fuel production costs included in the PSA relate to environmental chemical expenses, which vary directly with power plant production. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The PSA allows for the refund or recovery of said costs that deviate from the base cost amount of $0.000744 per kWh.[1]

In addition, the PSA allows for the refund or recovery of the net margins from sales of emission allowances to the extent the actual sales margins deviate from the base cost amount of ($0.000001) per kWh,[2] and for recovery of mandated carbon emission costs when it is economical to incur those costs as discussed below.

APS shall not incur mandatory carbon emission allowance costs unless it passes those costs on to the California entities that are purchasing energy from APS. In no event shall APS incur

[1] $0.000744 per kWh is the result of the following: (2021-2022 Test Year chemical costs of $21,278,000 / 2021-2022 Test Year native load sales of 28,592,000 MWh) / 1000.

[2] ($0.000001) per kWh is the result of the following: (2015 net gains from sales of SO_2 allowances of $25,181 / 2015 test year native load sales of 27,030,686 MWh) / 1000.

California's carbon emission allowance costs when doing so is not an economical choice for APS's Arizona ratepayers.

The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs and environmental chemical costs for fossil fuel production, and margins on the sales of emission allowances ("PSA Costs") to set a rate that is then reconciled to actual costs experienced.

This PSA includes a limit of $0.006 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year absent express approval of the Commission. This PSA also provides a mechanism for mid-year rate adjustment by either the Commission or the Company (only if overcollection occurs) in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

In addition to the PSA Rate described below, the PSA includes a mechanism that directly assigns Fuel and Purchased Power Cost for new growth-related generation resources procured to support APS generation resources, or through purchased power agreements (PPAs) by proportionally allocating the cost to the classes of customers creating that growth. The Fuel and Purchased Power Direct Assignment Cost is based on forecasted year-over-year growth in kWh sales and is incrementally allocated at the beginning of each PSA Year. These incremental, allocated costs are recovered through Adjustment Schedule PSA-1.

The Fuel and Purchased Power Direct Assignment Cost rate will not be included in the determination of the $0.006 per kilowatt-hour change limit in the PSA rate. The PSA limit of $0.006 per kilowatt, as described above, is applicable to the Forward Component, Historical Component, and Transition Component.

2. PSA Rate Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year's[3] PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual PSA Costs (fuel, purchased power and other allowable costs) and the recovery of those same cost elements through the combination of base rates and the Forward Component, and which provides for their recovery or refund during the next PSA Year.
3. The Transition Component, which provides for:
    a. The opportunity to seek mid-year changes in the PSA Rate in cases where variances between the anticipated recovery of fuel and purchased power and other allowable costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery/refund, should the Commission

[3] Each February 1 through January 31 period shall constitute a PSA Year.

deem such an adjustment to be appropriate or if the Company requests to make such a refund of an overcollection.

b. The tracking of balances resulting from the application of the Transition Components in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new general base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new general base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new general base rates.

On or before November 30 of each year, APS will submit a PSA Rate filing, which shall include a calculation of the three components of the proposed PSA Rate and the proposed Direct Assignment Cost rates. This filing shall be accompanied by such supporting information as Staff determines to be required.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February 1 and ends on the ensuing January 31, excluding any Fuel and Purchased Power Direct Assignment Costs. APS will submit, on or before November 30 of each year, a forecast, excluding any Fuel and Purchased Power Direct Assignment Costs for the upcoming PSA year (February 1-January 31) of its PSA Costs. It will also submit a forecast of kWh sales for the same period, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS's over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. The balance calculated as a result of these steps is then reduced by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e., February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual November 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the current PSA Year). The APS filing shall use these balances to calculate the Historical Component for the coming PSA Year.[4]

The November 30 filing's use of estimated balances for November through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1.

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

The Transition Component will be used as the method for incorporating any approved mid-year changes to the PSA rate. APS or Staff may request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate ($/kWh) imposed as part of the Transition Component. The Commission on its own motion may also change the PSA rate as described above.

Notwithstanding the preceding paragraph, APS may at any time during the PSA Year request to reduce the PSA through the Transition Component, which shall be deemed approved and become effective beginning with the first billing cycle of the month following the filing of such a request, provided APS files the request within the first 15 days of a month and Staff does not file opposition to the request.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

[4] For example, the November 30, 2008 filing would include actual balances for February through October of 2008 and estimated balances for November 2008 through January 2009.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before November 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year.

3. Calculation of the PSA Rate and the Fuel and Purchased Power Direct Assignment Costs

The PSA Rate is the sum of the three components; *i.e.,* Forward Component, Historical Component and Transition Component. The Fuel and Purchased Power Direct Assignment Costs are calculated in accordance with Decision No. XXXXX (*see* Schedule 10 to this POA). The PSA rate and the allocated Fuel and Purchased Power Direct Assignment Cost rates shall be applied to customer bills. Unless the Commission has otherwise acted on new rates by February 1, the proposed rates shall go into effect. However, the PSA Rate may not change from the prior year's PSA Rate by more than plus or minus $0.006 per kWh without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA Rate and the allocated Fuel and Purchased Power Direct Assignment Cost rates shall be applicable to APS's retail electric rate schedules (with the exception of E-36 XL, AG-X, Direct Access service and any other rate that is exempt from the PSA) and are adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes. Fuel and Purchased Power Direct Assignment Cost rates are calculated individually for customer classes based on growth in sales.

The PSA Rate and the Fuel and Purchased Power Direct Assignment Cost rates shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. They are not prorated.

4. Filing and Procedural Deadlines

a. Annual November 30 Filing

APS shall file the PSA Rate with all Component calculations and the Fuel and Purchased Power Direct Assignment Cost rates for the PSA Year beginning on the next February 1, including all supporting data, with the Commission on or before November 30 of each year. These calculations shall use a forecast of kWh sales and of PSA Costs for the coming PSA year, with all inputs and assumptions being the most current available for the Forward Component and Fuel and Purchased Power Direct Assignment Cost, where both forecast sales and forecast cost utilize the PSA year. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component, if necessary, shall

also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.[5]

b. Annual November 30 Filing Review Process

Commission Staff and interested parties shall have an opportunity to review the November 30 forecast, balances and supporting data on which the calculations of the three PSA components and the Fuel and Purchased Power Direct Assignment Costs have been based. Any objections to the November 30 calculations shall be filed within 60 days of the APS filing. Unless the Commission has otherwise acted on the APS calculations by February 1, the rates proposed by APS shall go into effect with the first February billing cycle.

c. Additional Filings and Notifications

APS shall also file with the Commission any additional information that Staff determines it requires to verify the component calculations, account balances and any other matter pertinent to the PSA.

Additionally, APS will file in both the docket in which the then-current PSA rate was approved, if applicable, and in the docket for the most recently completed general rate case notifying Commission Staff when the under-collected or over-collected PSA balance is greater than $100 million. The notice will include the current balances of the PSA and include a proposal for how the under-collection or over-collection should be addressed through the transition component with supporting calculations. Staff shall, within 60 days after the filing of such notification and proposal, review the notification and proposal, contact APS to obtain any supporting data necessary to review the calculations, and file in the docket in which the then-current PSA rate was approved, with a copy to the docket for the most recently completed general rate case, a Staff Report and Proposed Order analyzing the notification and proposal and recommending whether and in what manner the under-collection or over-collection should be addressed through the transition component of the PSA.

5. Verification and Audit

The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power and other allowable costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any

[5] This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.

costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest – Interest is applied on the PSA balance annually at the following rates: any over-collection existing at the end of the PSA year will be credited an amount equal to interest at a rate equal to the Company's authorized Return on Equity ("ROE") or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the end of the PSA Year will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

Base Chemical Costs – An amount generally expressed as a rate per kWh, which reflects the non-fuel production costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The Base Chemical Costs are set at $0.000744 per kWh effective on March 8, 2024.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power costs embedded in base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the composite base cost at $0.043881 per kWh across the 4 classes (Residential, Other General Service, E-34 and E-35, and XHLF) effective on XXX, XX, 202X.

Base Fuel less New Incremental Generation - Base Cost of Fuel and Purchased Power less Base Fuel and Purchased Power Direct Assignment Costs is an amount generally expressed as a rate per kWh, which reflects the fuel and purchased power costs embedded in base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at $0.042566 per kWh effective on XXX, XX, 202X.

Base Fuel and Purchased Power Direct Assignment Costs – An amount generally expressed as a rate per kWh reflecting Fuel and Purchased Power Incremental Costs approved in Decision No. XXXXX. Base Fuel and Purchased Power Direct Assignment Costs are allocated to four separate rate classes: 1) Residential - $0.000872 per kWh, 2) Other General Service - $0.000414 per kWh,[6] 3) Rate Schedules E-34 and E-35 - $0.004979 per kWh, and 4) Rate Schedule XHLF - $0.004779 per kWh.

[6] For purposes of this calculation, Other General Service includes all General Service and Classified rate schedules that are not identified as a separate class.

Fuel and Purchased Power Incremental Costs – An amount reflecting the annual fuel and purchased power cost related to forecasted new incremental generation procured to support APS generation resources, or through PPAs to serve growth. Fuel and Purchased Power Incremental Costs, are updated annually, and are used to determine the Fuel and Purchased Power Direct Assignment Costs for the upcoming PSA Year.

Fuel and Purchased Power Direct Assignment Costs – An amount generally expressed as a rate per kWh reflecting Fuel and Purchased Power Incremental Costs for the upcoming PSA Year. Fuel and Purchased Power Direct Assignment Costs are allocated to four separate rate classes based on year-over-year growth in sales: 1) Residential, 2) Other General Service,[7] 3) Rate Schedules E-34 and E-35, and 4) Rate Schedule XHLF, as calculated in Schedule 10 to this POA. These rates are updated annually on February 1 of each year and are effective with the first billing cycle in February.

Base Net Margins on the Sale of Emission Allowances - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of SO_2 emission allowances embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at ($0.000001) per kWh effective on March 8, 2024.

Base PSA Costs - A rate equal to the sum of Base Cost of Fuel and Purchased Power and Fuel and Purchased Power Direct Assignment Costs as defined above, the Base Chemical Costs, and the Base Net Margins on the Sale of Emission Allowances.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and is effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecast PSA Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS's base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis APS's over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue, plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and is effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism

[7] For purposes of this calculation, All Other General Service includes all General Service and Classified rate schedules that are not identified as a separate class.

to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest at year end. The balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mandated Carbon Emission Allowance Costs – The costs incurred in purchasing allowances to meet legal requirements, beginning in 2013, that electricity from resources which emit carbon must be accompanied by carbon emission allowances equal to the amount of carbon emitted in generating the electricity (recorded in FERC Account 509 – Allowances).

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load refers to the energy needed for customer load in the balancing authority area for which APS has a generation service obligation.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

PSA - The Power Supply Adjustment mechanism approved by the Commission.

PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus costs for environmental chemicals used in power production at fossil and nuclear production sites, storage product costs and the Net Margins on the Sales of Emission Allowances.

PSA Year - A consecutive 12-month period generally beginning each February 1.

Storage Product Costs - All costs associated with third-party storage facilities, including rent, capacity, and lease payments for electricity storage facilities (e.g., batteries) that APS utilizes in the dispatch of generated or purchased electricity.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with

applicable special contracts, E-36 XL, AG-X, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No. 78317.

System Book Off-System Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS's electricity over transmission facilities owned by others.

7. Schedules

Samples of the following schedules are attached to this Plan of Administration.

Schedule 1	PSA Rate Calculation
Schedule 2	PSA Forward Component Rate Calculation
Schedule 3	PSA Year Forward Component Tracking Account
Schedule 4	PSA Historical Component Rate Calculation
Schedule 5	Historical Component Tracking Account
Schedule 6	PSA Transition Component Rate Calculation
Schedule 7	PSA Transition Tracking Account
Schedule 8	Summary of Monthly Calculations
Schedule 9	Native Load Customer Counts, Sales and Revenue
Schedule 10	Fuel and Purchased Power Direct Assignment Cost Calculation

8. Compliance Reports

APS shall provide monthly reports to Staff and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in APS's annual report filed with the Commission's Corporations Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her

information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
    a. Total power and fuel costs
    b. Margins on the sale of excess emission allowances
    c. Environmental chemical costs for fossil generation
    d. Customer sales in both MWh and thousands of dollars by customer class
    e. Number of customers by customer class
    f. A detailed listing of all items excluded from the PSA calculations
    g. A detailed listing of any adjustments to the adjustor reports
    h. Total off-system sales revenues
    i. System losses in MW and MWh
    j. Monthly maximum retail demand in MW

2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively
2. Average heat rate, both monthly and 12-month average
3. Equivalent forced-outage factor, both monthly and 12-month average
4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description
5. Total fuel costs per month
6. The fuel cost per kWh per month

B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh
2. The demand purchased in MW to the extent specified in the contract
3. The total cost for demand to the extent specified in the contract
4. The total cost of energy

C. Information on off-system sales shall include the following items:

1. An itemization of off-system sales margins per buyer
2. Details on negative off-system sales margins

D. Fuel purchase information shall include the following items:

1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel
2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm or per MCF, total cost, supply basin and volume by contract

E. APS will also provide:

1. Monthly projections for the next 12-month period showing estimated over/under-collected amounts
2. A summary of unplanned outage costs by resource type
3. A summary of the net margins on the sale of emission allowances
4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing
5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, costs for specified environmental chemicals that vary with power generated at fossil power plants, storage product costs, and the net margins on the sale of emission allowances and Mandated Carbon Emission Allowance Costs will also be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission (FERC) accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)

- 509 Allowances[8]

Additionally, broker fees recorded in FERC account 557 up to the amount included in the Base Fuel Cost and costs for environmental chemicals used in power production in FERC accounts 502 and 549 are allowable accounts.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Treatment of Directly Assignable Power Supply Costs

Decision No. 66567 (November 18, 2003) provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 XL and AG-X customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs and kWh usage are excluded from the PSA.

[8] Or any successor FERC account used to record the costs of purchasing carbon emission allowances.

REBUTTAL TESTIMONY OF JAMES M. COYNE
On Behalf of Arizona Public Service Company
Docket No. E-01345A-25-0105

April 3, 2026

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JMC-2RB - Proxy Group Selection
JMC-3RB - Constant Growth DCF Model
JMC-4.1RB - Beta Coefficients for CAPM Analysis
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DIRECT TESTIMONY OF JAMES M. COYNE
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-25-0105)

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James M. Coyne. My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Concentric Energy Advisors, Inc. (Concentric) as a Senior Vice President.

Q. DID YOU ALSO FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I submitted Direct Testimony on behalf of Arizona Public Service Company (APS or Company) to the Arizona Corporation Commission (ACC or Commission) in June 2025. APS is a wholly-owned subsidiary of Pinnacle West Capital Corporation (Pinnacle West).

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony of Mr. David C. Parcell on behalf of the Utilities Division (Staff) of the Arizona Corporation Commission, Mr. Mark E. Ellis on behalf of the Arizona Attorney General's Office (AGO), Dr. Zhen Zhu on behalf of the Residential Utility Consumer Office (RUCO), Mr. Christopher C. Walters on behalf of the Federal Executive Agencies (FEA), Mr. David J. Garrett on behalf of the Arizona Large Customer Group and Freeport Minerals Corporation (LCG), and Dr. Jaime McGovern on behalf of Walmart, Inc. (collectively,

"ROE witnesses") as it relates to the authorized ROE, capital structure, and return on the Fair Value Rate Base (FVRB) increment for APS in this proceeding.

Q. ARE YOU FILING ANY REBUTTAL EXHIBITS TO SUPPORT YOUR TESTIMONY?

A. Yes. My rebuttal analyses and conclusions are supported by the data presented in Attachment JMC-1RB through Attachment JMC-7RB, which were prepared by me or under my direction.

II. EXECUTIVE SUMMARY

Q. PLEASE SUMMARIZE THE ROE, CAPITAL STRUCTURE, AND RETURN ON THE FAIR VALUE INCREMENT RECOMMENDATIONS OF THE OTHER ROE WITNESSES.

A. The other ROE witnesses in this proceeding recommend an authorized ROE for APS from 6.10 percent (AGO witness Mr. Ellis) to 9.80 percent (Staff witness Mr. Parcell). Several witnesses recommend a lower authorized ROE for APS if the proposed Formula Rate Adjustment Mechanism (FRAM) is approved. Figure 1 summarizes the ROE, capital structure and return on the Fair Value Increment (FVI) recommendations of the witnesses in this proceeding.

Figure 1: Summary of Recommendations

Party	Witness	ROE (no FRAM)	ROE (with FRAM)	Equity Ratio	Return on FVI
APS	Coyne	10.70%	10.70%	52.35%	0.90[1]
Staff	Parcell	9.80%	9.55%	52.35%	0.00% - 0.93%
RUCO	Zhu	9.20%	9.00%	52.35%	0.00%
AGO	Ellis	6.10%	6.10%	52.35%	0.00%
FEA	Walters	9.45%	9.30%	52.35%	0.00%-0.20%
LCG	Garrett	8.50%	8.10%	42.00%	N/A
Walmart	McGovern	N/A	N/A	N/A	0.00%

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR REBUTTAL TESTIMONY.

A. As discussed throughout my Rebuttal Testimony, the ROE recommendations of two of the ROE Witnesses should be rejected at the outset because they are clearly insufficient to meet the standards for a just and reasonable return. In particular, the ROE recommendations of Mr. Ellis and Mr. Garrett are substantially below the level of authorized equity returns for other vertically-integrated electric utilities and would not allow APS to compete for capital on reasonable terms. Further, Mr. Ellis' and Mr. Garrett's extreme recommendations, if adopted, would jeopardize the financial integrity of APS and almost certainly lead to a credit rating downgrade for APS, as well as being detrimental to existing shareholders of APS's parent company, PNW. While the other ROE witnesses' recommendations are more plausible from the standpoint of APS's peer group, they are still below the level appropriate to reflect investors' return requirements for the Company, given APS's investment risk profile.

[1] APS have revised its requested return on the FVRB increment from 1.00 percent in its Direct filing

The following is a summary of my key conclusions in rebuttal:

- My ROE recommendation of 10.70 percent for APS continues to be supported by my updated analysis, based on market data as of February 27, 2026. Contrary to the testimony of certain of the other ROE witnesses, I have used commonly accepted models and reasonable and appropriate inputs to those models to estimate the cost of equity for APS. Those methodologies are consistent with how investors set their return requirements for a company with the business and financial risk profile of APS.
- Interest rates on long-term government bonds are demonstrably higher than when the Commission set the current authorized ROE of 9.55 percent for APS. For example, the average yield on 30-year Treasury bonds has increased by approximately 90 basis points since APS's previous rate case was filed, and on a test-year basis, the yield has increased by 155 basis points. Although the Federal Reserve has significantly reduced short-term interest rates as inflation has eased from the highest level in 40 years, interest rates on long-term Treasury and utility bonds have remained near the prevailing levels when my Direct Testimony analysis was conducted. Forecasts indicate that bond yields are expected to remain near current levels through at least 2031. There is no evidence that capital costs have declined since the filing of my Direct Testimony.
- Staff witness Parcell's base ROE of 9.80 percent is generally consistent with average authorized ROEs for vertically integrated electric utilities since 2024 of 9.86 percent. However, Mr. Parcell's recommendation fails to take into

consideration the unique business risks of APS which cause equity investors to require a higher return. For example, APS co-owns and operates the second largest nuclear power plant in the United States, similar to companies such as Florida Power & Light which has an authorized ROE of 10.95 percent, with the ability to earn up to 11.95 percent on 59.6 percent equity; and Georgia Power Company which has an authorized ROE of 10.50 percent, with the ability to earn up to 11.9 percent on 56.0 percent equity.

- While Messrs. Ellis and Garrett use commonly accepted models such as the DCF and CAPM to estimate the cost of equity for APS, their inputs to those models are not reasonable and produce such low ROE estimates that they should be rejected by the ACC. For example, Mr. Ellis' ROE recommendation of 6.10 percent is only slightly above the 30-day average interest rate on Moody's Baa-rated utility bonds of 5.81 percent and is inconsistent with a fundamental principle of finance--the cost of equity is greater than the cost of debt.
- If the ACC were to adopt the recommendations of either Mr. Ellis or Mr. Garrett, the market reaction would be negative and immediate, as shown by the prior experience in Arizona in November 2021 when the Commission approved an authorized ROE of 8.70 percent for APS,[2] which is well above the levels recommended by these two witnesses. It is reasonable to expect that adopting the recommendations of either Mr. Ellis or Mr. Garrett would lead to a credit downgrade for APS, a sharp decline in the share price of PNW, higher costs of

[2] The ACC initially approved an ROE of 8.70 percent for APS, which included a 20 basis point penalty for poor customer service. APS appealed the Commission's decision to the Arizona Court of Appeals, and the ROE penalty was ultimately removed in August 2023. The authorized ROE was then 8.90 percent.

both debt and equity for APS's customers, and trouble accessing capital to finance the Company's capital expenditure program.

- APS's proposed capital structure is consistent with the actual and authorized capital structures of the operating companies held by my proxy group companies. The Commission should give no weight to the arguments of Messrs. Parcell and Garrett, each of whom testifies that APS's has substantially lower financial leverage (i.e., debt) than the proxy group companies. These witnesses base their opinions on an analysis of the holding company capital structures which is not the correct point of comparison. As discussed in my Rebuttal Testimony, this comparison should be performed at the operating company level.
- APS's proposed FRAM should be approved by the Commission without making a downward adjustment to the Company's authorized ROE. The FRAM has important credit supportive elements that will align APS more closely with its peers in the proxy group, approximately 26 percent of which already operate under formula rates or multi-year rate plans and many others which have regulatory mechanisms that support credit quality through timely recovery of operating and capital costs. The FRAM will improve the opportunity for APS to earn its authorized ROE by reducing the regulatory lag that has caused the Company to significantly underearn its authorized return in recent years. Approval of the FRAM, however, does not mitigate the other business risks of APS, including its planned capital spending, its ownership of nuclear generation, and its potential wildfire risk, among others. See the Rebuttal Testimony of APS

witness Chris R. Bauer and pages 65-66 of my Rebuttal Testimony for more details on APS's business risks.

- The Commission should approve APS's proposed return on the Fair Value Rate Base, including the return on the Fair Value Increment of 0.9 percent.[3] This is a conservative request that is intended to give effect to the Arizona constitution and court decisions that allow utilities to earn a return on FVRB, while recognizing the importance of maintaining affordable rates for APS's customers. Several of the other witnesses recommend no return on the FVI; however, that is not a reasonable position because it ignores the state constitution and court decisions that have permitted utilities to earn a return on the FVRB.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

A. The balance of my Rebuttal Testimony is organized by topic/issue as follows: Section III provides a comparison of the recommended ROEs of the various witnesses to the nationwide average ROE for vertically-integrated electric utilities. Section IV presents an updated overview of current and projected economic and capital market conditions and the implications for utility cost of capital. Section V discusses areas of disagreement concerning the composition of the proxy group for APS in this proceeding. Section VI discusses the use of the DCF model to estimate the ROE for APS, and areas of disagreement among the witness as to the form of the DCF model and the appropriate inputs and assumptions. Section VII discusses the CAPM method and areas of

[3] APS, Rebuttal Testimony of Chris Bauer (Apr. 3, 2026) at 23

disagreement regarding the reasonable inputs and assumptions of that model. Section VIII discusses the relevance of the Risk Premium model and areas of disagreement concerning the form/structure of that model and the appropriate inputs. Section IX discusses the Expected Earnings model, its relevance in estimating the authorized ROE for APS, and the appropriate inputs to that model. In Section X, I respond to testimony from other witnesses regarding the business risks faced by APS and how those affect the authorized ROE for the Company in this proceeding. In Section XI, I respond to claims of other witnesses that the proposed FRAM reduces the risk of APS and therefore should result in a lower authorized ROE than if the FRAM were not implemented. In Section XII, I address the testimony of other witnesses who challenge the capital structure proposed by APS in this proceeding. In Section XIII, I respond to comments and recommendations of other witnesses as it relates to the appropriate return on the FVRB increment. Lastly, Section XIV summarizes my results, conclusions, and recommendations.

III. COMPARISON TO RETURNS IN OTHER JURISDICTIONS

Q. ARE RETURNS IN OTHER JURISDICTIONS A RELEVANT BENCHMARK THAT INVESTORS CONSIDER IN ESTABLISHING THEIR RETURN REQUIREMENTS FOR REGULATED UTILITIES SUCH AS APS?

A. Yes, they are, as long as differences in the timing of these decisions and the relative risk of the respective utilities are considered. According to data from Regulatory Research Associates (a unit of S&P Global Market Intelligence), the average authorized ROE for

vertically-integrated electric utilities since January 2024 is 9.86 percent.[4] Walmart witness McGovern provides similar data on authorized ROEs for electric utilities and vertically-integrated electric utilities in his testimony.[5] By comparison, the ROE recommendations of Mr. Ellis, Mr. Garrett, and Dr. Zhu are substantially lower, while the recommendations of Mr. Parcell and Mr. Walters are closer to the national average authorized ROE but well below the market-based cost of equity for APS, as shown in my ROE analyses.

These witnesses have not provided any persuasive evidence to support an argument that APS has lower risk than the proxy group companies or other integrated electric utilities generally. Therefore, it is not reasonable to conclude that APS's authorized ROE should be set 65 to 375 basis points lower than the average for vertically integrated utilities, and even further below nuclear operators such as Florida Power and Light and Georgia Power. As discussed in my Direct Testimony, certain factors indicate that APS has greater than average business risk compared to the proxy group companies, which supports an authorized ROE above the proxy group average.[6] These risk factors include the Company's capital expenditure program, its regulatory environment and cost recovery mechanisms relative to a set of proxy companies (described later in my testimony), its ownership of generation assets including a nuclear plant, and its exposure to wildfire risk. In addition, the models I used to estimate the ROE for APS produced average results of approximately 10.70 percent based on market data as of March 31,

[4] Source: Regulatory Research Associates, rate case decisions as of March 5, 2026.
[5] Direct Testimony of Dr. Jaime McGovern, at 20-22.
[6] Direct Testimony of James M. Coyne, at 44-45.

2025, and 10.90 percent using updated market data as of February 27, 2026. Moreover, since the end of February 2026, economic and capital market conditions have become more uncertain with the ongoing Middle East conflict, the resulting spike in oil prices, elevated volatility in the stock market, and higher Treasury bond yields. The Company's requested ROE, supported by my analysis and recommendation, remains at 10.70 percent.

Q. WHAT ARE THE GUIDING PRINCIPLES USED IN ESTABLISHING THE COST OF CAPITAL FOR A REGULATED UTILITY?

A. As discussed in my Direct Testimony, utilities are entitled by law to the opportunity to earn a fair rate of return sufficient to attract needed capital at reasonable rates. The *Hope* and *Bluefield* decisions include three standards for a fair return. Specifically, the ACC's order in this case should provide APS with the opportunity to earn a return on equity that is:

- Commensurate with returns on investments in enterprises having comparable risks;
- Adequate to attract capital on reasonable terms, thereby enabling APS to provide safe, reliable service; and
- Sufficient to ensure the financial soundness of the Company's operations.

Importantly, a fair return must satisfy all three of these standards.

Q. DO THE ROE RECOMMENDATIONS OF THE OTHER ROE WITNESSES SATISFY THE REQUIREMENTS OF HOPE AND BLUEFIELD?

A. No, they do not. Specifically, the equity returns recommended by the other witnesses with the exception of Staff witness Parcell are well below the average authorized ROE for integrated electric utilities and on that basis alone do not meet the comparability standard. In addition, the ROE recommendations of Mr. Ellis and Mr. Garrett are not sufficient to meet the capital attraction standard, based on the market's negative reaction to a return authorization for APS of 8.70 percent in November 2021, which is above the recommendations of Mr. Ellis and Mr. Garrett in this proceeding. Finally, Mr. Ellis's ROE recommendation and Mr. Garrett's ROE and capital structure recommendations also fail the financial integrity standard, because returns at this level would most certainly lead to credit downgrades for both APS and PNW, as well as higher debt and equity costs for APS and its customers.

Q. MR. ELLIS CONTENDS THAT AUTHORIZED ROES IN THE U.S. DID NOT TRACK THE DECLINE IN INTEREST RATES THAT OCCURRED AFTER THE FINANCIAL CRISIS OF 2007-2009.[7] DO YOU AGREE THAT AUTHORIZED ROES FOR ELECTRIC UTILITIES HAVE BEEN DISCONNECTED FROM CHANGES IN TREASURY BOND YIELDS?

A. No, I do not agree. As shown in my Risk Premium analysis, there is a strong relationship between Treasury bond yields and authorized ROEs for integrated electric utilities.[8] The R^2 of the regression equation is 0.79, which indicates that changes in Treasury bond

[7] Direct Testimony of Mark E. Ellis, at 13, 18-19.
[8] Direct Testimony of James M. Coyne, at 33-34, Attachment JMC-5DR.

yields (both up and down) have accounted for the vast majority of the change in the authorized ROE since 1992. Therefore, the data does not support Mr. Ellis' position that authorized ROEs have not tracked the decline (or the recent increase) in government bond yields.

Q. ACCORDING TO MR. ELLIS, THE RETURN FOR THE BROAD MARKET IN THE U.S. IS EXPECTED TO BE APPROXIMATELY 6.0 PERCENT OVER THE NEXT TEN YEARS.[9] IS THIS RELEVANT TO ESTABLISHING THE AUTHORIZED ROE FOR A REGULATED UTILITY SUCH AS APS?

A. No, it is not. Mr. Ellis argues that regulated utilities are generally considered to have lower than average risk, and he frames his ROE recommendation by comparison to expected returns for the broad market. He cites the forecasts of several investment banks and concludes that the average expected market return over the next ten years in the U.S. is about 6.0 percent.[10] The expected return for the broad market is not the same as the investor-required return for a particular company. Specifically, the investor-required return is the return required by investors that would induce them to invest money into the company, whereas the expected return for the broad market is a projection of the total return (dividend yield and capital appreciation) that investors expect on a market index such as the S&P 500 or the NYSE Composite. The two terms should not be conflated, as Mr. Ellis has done, because they do not measure the same thing.

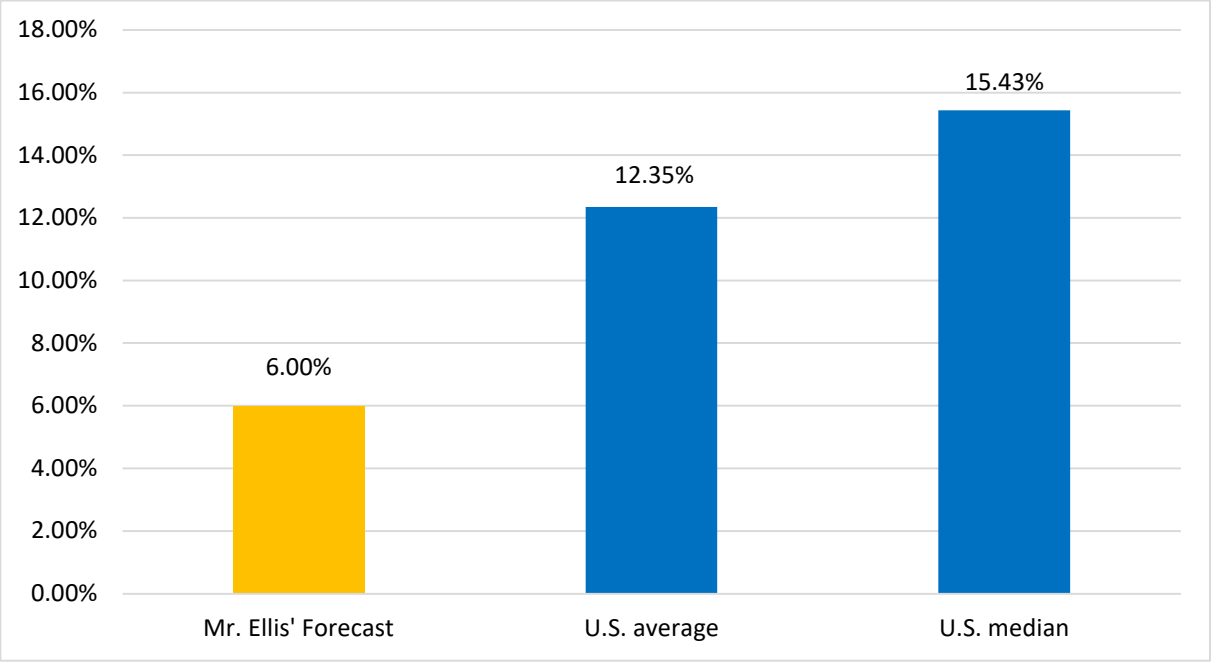
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[9] Direct Testimony of Mark E. Ellis, at 19-21, Figure 2.
[10] Source: Kroll, Cost of Capital Navigator.

Q. SETTING ASIDE THAT CONCERN, HOW DOES THE 6.0% EXPECTED MARKET RETURN CITED BY MR. ELLIS COMPARE TO THE AVERAGE HISTORICAL RETURNS FOR LARGE COMPANY STOCKS IN THE U.S.?

A. In order to assess the reasonableness of this projected market return, I compared it to the average historical returns in the U.S. from 1926-2025, provided by Kroll. As shown in Figure 1 below, the arithmetic average and median returns in the U.S. over that period have been 12.35 percent and 15.43 percent, respectively. In other words, the average historical market return on large company stocks in the U.S. since 1926 has exceeded the 6.0 percent forecast relied on by Mr. Ellis by approximately 106 percent. Further, the total return in the U.S. has exceeded 6.0 percent in 64 of 100 years (or 64% of the time), suggesting that the market return benchmark used by Mr. Ellis is unreasonably low by historical standards.

Figure 1: Average Historical Market Returns – 1926-2025



One could argue that the historical market returns shown in Figure 1 do not consider current levels of inflation. The average CPI in the U.S. from 1926-2025 was 3.02 percent according to the U.S. Bureau of Labor Statistics, meaning that U.S. stocks have provided a real return of 9.33 percent over the past 100 years. According to Blue Chip Financial Forecasts, inflation is expected to decline from 2.9 percent in the fourth quarter of 2025 to around 2.5 percent by the first quarter of 2027,[11] although there is some risk that actual inflation will be higher. Assuming an inflation rate of 2.5 percent at the beginning of 2027, plus the historical real market return of 9.33 percent, produces a nominal market return for the U.S. of 11.83 percent. While lower than the average historical market return of the past 100 years, this remains substantially higher than the 6.0 percent forecast relied upon by Mr. Ellis in setting overall return expectations for U.S. equities.

Q. MR. ELLIS PRESENTS AN "OPTIMIZATION ANALYSIS" THAT HE CLAIMS DEMONSTRATES THAT APS WOULD BE ABLE TO MAINTAIN ITS CASH FLOW RELATED CREDIT METRICS AND ITS INVESTMENT GRADE CREDIT RATING IF THE COMMISSION WERE TO ADOPT HIS ROE RECOMMENDATION OF 6.10 PERCENT.[12] WHAT IS YOUR RESPONSE?

A. This assertion by Mr. Ellis is entirely without merit. APS's current credit ratings are based on an authorized ROE of 9.55 percent and a return on the Fair Value Increment of 25 basis points, which makes for an effective ROE of 9.85 percent. If the ACC were to approve a reduction to the authorized ROE for APS to 6.10 percent, as recommended

[11] Blue Chip Financial Forecasts, Vol. 45, No. 3, February 27, 2026, at 2.
[12] Direct Testimony of Mark E. Ellis, at 92-96.

by Mr. Ellis, the Company's credit metrics would not be consistent with the current BBB+/Baa1 rating, as discussed in the Rebuttal Testimony of APS witness Chris R. Bauer. Furthermore, a return at the level recommended by Mr. Ellis would be perceived by credit rating agencies as evidence that the regulatory climate in Arizona was not supportive of utility credit quality. In turn, it is reasonable to expect that the business risk ranking for APS would be reduced by S&P and that Moody's would assign lower ratings to its assessment of APS's business risk profile. In all probability, these changes would cause a credit downgrade for APS, thereby leading to higher costs for both debt and equity to the disadvantage of APS's customers.

Q. HOW DO MR. GARRETT'S RECOMMENDATIONS COMPARE TO THE AVERAGE RETURNS FOR VERTICALLY-INTEGRATED UTILITIES?

A. Mr. Garrett recommends an authorized ROE for APS of 7.9 percent (assuming the Commission approves the proposed FRAM and the actual test year capital structure, which includes 52.35 percent common equity) or 8.1 percent with his recommended common equity ratio of 42.00 percent. In addition, Mr. Garrett recommends that the Commission not approve a return on the Fair Value Increment. The combination of Mr. Garrett's recommended ROE and capital structure produces a weighted ROE (i.e., authorized ROE times equity ratio) of 3.40 percent.[13] By comparison, the average authorized ROE for vertically integrated electric utilities since January 2024 is 9.86 percent and the average authorized equity ratio is approximately 51.24 percent, resulting in a weighted ROE of 5.05 percent. In other words, Mr. Garrett's weighted ROE

[13] Calculation: recommended ROE of 8.1% X equity ratio of 42.00% = 3.40% weighted ROE.

recommendation for APS is 1.73 percentage points lower than the national average for vertically integrated electric utilities. This gap is even greater compared to peers such as FPL (3.12 percent) or Georgia Power (2.48 percent) before consideration of the upper end of their earnings bands. Furthermore, as discussed in my Direct and Rebuttal Testimonies and the testimony of APS witness Chris R. Bauer, APS has greater business risk than the proxy group, which suggests that the authorized return for the Company should be higher than average, not materially lower as Mr. Garrett recommends.

Q. PLEASE DISCUSS THE POTENTIAL CONSEQUENCES IF THE COMMISSION WERE TO SET THE AUTHORIZED ROE FOR APS AT THE LEVELS RECOMMENDED BY EITHER MR. ELLIS (6.1%) OR MR. GARRETT (8.1% IF THE FRAM IS APPROVED OR 7.9% IF THE FRAM IS APPROVED ALONG WITH APS'S ACTUAL TEST YEAR CAPITAL STRUCTURE).

A. If the Commission were to set the authorized ROE for APS at the levels recommended by Messrs. Ellis or Garrett, we need only look to a prior ACC decision to understand how the market is likely to react. The Commission issued a decision in APS's 2019 rate case in which the authorized ROE was set at 8.70 percent in November 2021.[14] The market reaction was negative and immediate. All three major credit rating agencies, S&P, Moody's, and Fitch, downgraded the long-term issuer rating of APS and its parent, PNW, by one notch, as shown in Figure 3 and Figure 4 below. This credit downgrade

[14] Arizona Corporation Commission, Opinion and Order, Decision No. 78317, Docket No. E-01345A-19-0236 (Phoenix, AZ, Nov. 9, 2021); Order on Remand Adopting Joint Resolution, Decision No. 78979, Docket No. E-01345A-19-0236 (Phoenix, AZ, June 28, 2023).

increases the cost of future borrowing (a cost which is paid by APS's customers), because interest rates on future debt issuances are higher when the debt rating is lower.

Figure 3: Arizona Public Service Credit Rating History

	Action	Date
Moody's	A2 (no change) Put on WATCH for downgrade (Outlook)	12-Oct-21
	Downgraded from A2 to A3	17-Nov-21
	Downgraded from A3 to Baa1	20-Mar-24
S&P	A- (no change) Put on WATCH Negative	14-Oct-21
	Downgraded from A- to BBB+, Negative Outlook	9-Nov-21
	BBB+ (no change), Negative to Stable Outlook	7-Mar-24
Fitch	Downgraded from A- (NEG) to BBB+ (NEG)	12-Oct-21
	BBB+ (no change), Negative to Stable Outlook	16-Mar-24

Figure 4: Pinnacle West Capital Corp. Credit Rating History

Moody's		
	A3 (no change) Put on WATCH for downgrade (outlook)	12-Oct-21
	Downgraded from A3 to Baa1	17-Nov-21
	Downgraded from Baa1 to Baa2	20-Mar-24
S&P		
	A- (no change), Put on WATCH Negative	14-Oct-21
	Downgraded from A- to BBB+, Negative outlook	09-Nov-21
	BBB+ (no change), Negative to Stable Outlook	07-Mar-24
Fitch	Downgraded from A-(NEG) to BBB+(NEG)	12-Oct-21

Downgraded from BBB+ (NEG) to BBB (Stable)	26-Mar-24

In addition, the stock price of PNW dropped sharply, declining by approximately 28 percent from around $88/share in June 2021 to about $63.00/share in November 2021, as shown in Figure 5. With a subsequent reversal of this decision, the share price for PNW has recovered to over $100/share.

Figure 5: Effect on PNW Share Price of 2021 Decision



Mr. Ellis references articles published by Dr. Steven Kihm as support for his views on utilities' ability to attract capital even when the ROE is set below the cost of equity.[15] What Mr. Ellis fails to mention is that even though Dr. Kihm contends that utilities can always attract capital, Dr. Kihm concedes that the share price may need to decline in order to attract potential investors, and he acknowledges that the authorized return

[15] Direct Testimony of Mark E. Ellis, at 35.

should be set at a level that does not significantly harm existing investors. In his testimony in Wisconsin in a rate case involving Northern States Power Wisconsin, a subsidiary of Xcel Energy Inc., Dr. Kihm recommended an authorized ROE of 9.50 percent even though he argued that the cost of equity for utilities is in the range of 7.7 to 7.8 percent.[16] Contrary to the position of these intervenors, capital does not flow freely regardless of the authorized ROE, and there are real world consequences of setting the authorized return lower than what is fair and reasonable.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE ROE AND CAPITAL STRUCTURE RECOMMENDATIONS OF THE OTHER WITNESSES?

A. The analysis I provided in my Direct Testimony provides a reasonable basis for determination of APS's authorized ROE, and satisfies the requirements of a fair return. This is a critically important time for utilities, including APS, to meet customers' growing requirements for a safe a reliable network to meet their electric energy needs. Lower estimates of the required return, while tempting from a customer perspective, would undermine the ability of the Company to raise the substantial debt and equity capital required to meet these requirements.

[16] Public Service Commission of Wisconsin, Docket No. 4220-UR-127, Direct Testimony of Steven Kihm on behalf of Citizens Utilities Board, at 3.

IV. UPDATED ROE ANALYSIS

Q. HAVE YOU UPDATED YOUR ROE ANALYSIS FOR APS IN THIS PROCEEDING?

A. Yes, I updated my ROE analysis based on market data as of February 27, 2026, using the same financial models (i.e., the Constant Growth form of the Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), the Bond Yield Plus Risk Premium method (Risk Premium), and the Expected Earnings approach) and updated inputs to those models. I excluded two companies (TXNM Energy, Inc. and Portland General Electric Company) from my proxy group for APS, because both companies have announced subsequent transactions and therefore no longer meet my merger screen. Figure 6 summarizes the updated results, as compared to the results filed in my Direct Testimony, which were based on market data as of March 31, 2025. As shown in the Figure, the four-model average results have increased by 17 basis points from 10.73 percent to 10.90 percent.

Figure 6: Summary of Updated ROE Results

DCF – 90-day average	**3/31/25 (Direct)**	**2/27/26 (Rebuttal)**	**Change**
Constant Growth – Mean	10.16%	10.60%	+0.44%
Risk Premium – 30 Yr. U.S. Treasury			
30-Yr. U.S. Treasury – LT forecast	10.45%	10.56%	+0.11%
CAPM – Forward MRP, Forecast Bond Yield			
Value Line Beta	14.31%	13.21%	
Bloomberg Beta – 5-year	11.29%	11.37%	
Bloomberg Beta – 10-year	12.61%	13.33%	
CAPM – Historical MRP, Current Bond Yield			
Value Line Beta	11.51%	10.35%	

Bloomberg Beta – 5-year	9.42%	9.16%	
Bloomberg Beta – 10-year	10.33%	10.42%	
CAPM Average	11.58%	11.31%	-0.27%
Expected Earnings - Median	10.71%	11.13%	+0.42%
Mean of All Methods	**10.73%**	**10.90%**	**+0.17%**
Recommendation	**10.70%**		

Q. DOES THIS UPDATED ANALYSIS CONTINUE TO SUPPORT YOUR ROE RECOMMENDATION FOR APS?

A. Yes. The ROE analyses presented in my Direct Testimony indicated a range of results from 10.20 percent to 11.60 percent from a combination of models and alternative input assumptions. Based on the results of all four methods (i.e., DCF, CAPM, Risk Premium and Expected Earnings), and in light of the business risks of APS relative to the proxy group, combined with my observations pertaining to capital market conditions, my analyses supported an authorized ROE of 10.70 percent for APS, just below the mean of all methods, My updated analyses based on market data as of February 27, 2026, demonstrates that my original recommendation is reasonable, if not slightly conservative, given current market conditions.

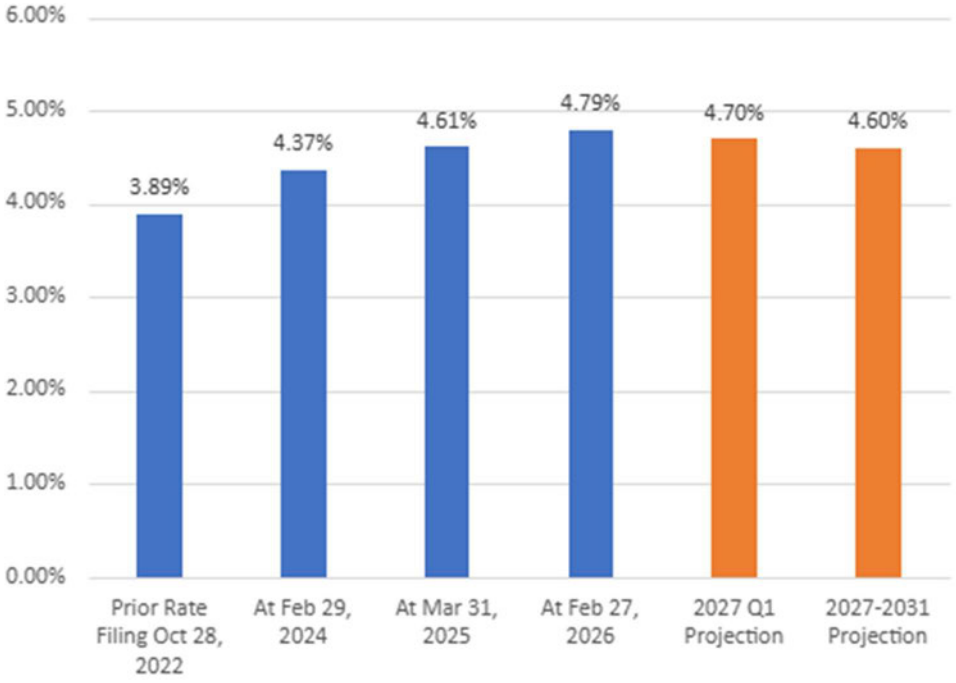
V. ECONOMIC AND CAPITAL MARKET CONDITIONS

Q. CERTAIN OTHER WITNESSES POINT OUT THAT THE FEDERAL RESERVE REDUCED THE FEDERAL FUNDS RATE ON SIX OCCASIONS IN 2024 AND 2025. IS THIS EVIDENCE THAT THE COST OF CAPITAL FOR

UTILITIES IS LOWER NOW THAN WHEN YOU FILED YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. No, it is not. While the Federal Reserve has cut short-term interest rates six times by a total of 150 basis points in the past two years, yields on longer-term Treasury and utility bonds are higher than when the Commission established APS's current authorized ROE of 9.55 percent and are projected to remain near current levels over the period from 2027-2031. I have updated the chart in my Direct Testimony (Figure 3), which compares Treasury bond yields at the time of APS's last rate case, to include more recent market information. As shown in Figure 7 below, the 30-day average yield on Treasury bonds as of February 27, 2026, was 4.79 percent, and the projected yield on 30-year Treasury bonds from 2027-2031 is 4.60 percent.

Figure 7: Comparison of U.S. Treasury Bond Yields[17]



As discussed in my Direct Testimony, higher yields on government bonds indicate that the cost of capital has increased for all companies, including utilities. Higher yields on long-term Treasury bonds present investors with a more attractive return on a "risk-free" alternative, and utility dividend yields must also increase in order for the companies to continue to attract equity capital. While I have used both current and forecast yields on government bonds as the risk-free rate in the CAPM and Risk Premium models, my general approach is to place the most weight on the projected government bond yield over the next five years in these two analyses.

Q. ACCORDING TO STAFF WITNESS PARCELL AND OTHERS, INFLATION IS EXPECTED TO DECLINE TOWARD THE FEDERAL RESERVE'S

[17] Source: Bloomberg Professional for historical data, Blue Chip Financial Forecasts for projected data as of December 1, 2025, and March 1, 2026.

STATED 2.0 PERCENT TARGET.[18] IS THERE RISK TO THIS INFLATION FORECAST, AND WHAT ARE THE EXPECTATIONS FOR INFLATION OVER THE NEXT FEW YEARS?

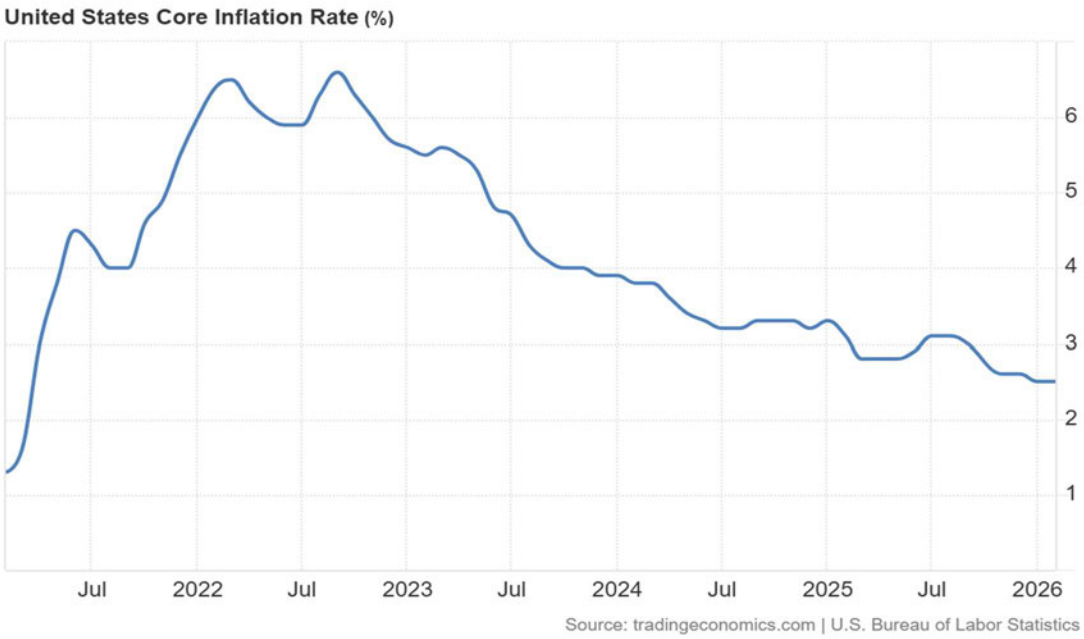
A. Yes, there is risk to the current inflation forecast due to geopolitical events such as evolving U.S. trade policy, uncertainty around the Supreme Court's decision ruling that certain tariffs are not constitutional and must be refunded, and recent events in the Middle East, particularly Iran. Figure 8 shows that the Core Inflation Rate, which excludes volatile food and energy prices, was 2.5 percent for the 12-month period as of February 2026. In addition, consumer and producer prices are expected to be impacted by the sharp increase in oil prices that occurred in March 2026 as supplies from the Middle East were constrained. This further increases uncertainty around the outlook for inflation. The Federal Reserve's preferred measure of inflation, the Personal Consumption Expenditure price index, was 2.8 percent (headline) and 3.1 percent (core) as of January 2026. All of these indicators remain above the Federal Reserve's long-term inflation target of 2.0 percent. Citing these reasons, the Federal Reserve decided to hold its current federal funds rate at its March 2026 meeting.

> Available indicators suggest that economic activity has been expanding at a solid pace. Job gains have remained low, and the unemployment rate has been little changed in recent months. Inflation remains somewhat elevated.
>
> The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. Uncertainty about the economic outlook remains elevated. The implications of developments in the Middle East for the U.S. economy are uncertain. The Committee is attentive to the risks to both sides of its dual mandate.

[18] Direct Testimony of David C. Parcell, at 11-12, 14-15.

In support of its goals, the Committee decided to maintain the target range for the federal funds rate at 3-1/2 to 3-3/4 percent.[19]

Figure 8: Core Inflation Rate[20]



The University of Michigan Survey of Consumer Sentiment noted in its February 2026 update, "[l]ong-run inflation expectations held steady at 3.3%, just above the 2.8% and 3.2% range seen in 2024. In 2019 and 2020, long-run inflation expectations were consistently below 2.8% ."[21] These survey results indicate that U.S. consumers are not expecting inflations to decline from current levels over the next several years.

Q. ACCORDING TO MR. PARCELL, MR. WALTERS AND DR. ZHU, THE SPREAD BETWEEN UTILITY AND TREASURY BONDS IS LOWER THAN

[19] Source: https://www.federalreserve.gov/newsevents/pressreleases/monetary20260318a.htm
[20] Source: https://tradingeconomics.com/united-states/core-inflation-rate
[21] University of Michigan Surveys of Consumers, https://www.sca.isr.umich.edu/ accessed March 7, 2026.

THE HISTORICAL AVERAGE. THEREFORE, THEY ARGUE THAT INVESTORS VIEW UTILITIES AS LESS RISKY THAN IN THE PAST.[22] DO YOU AGREE WITH THAT CONCLUSION?

A. No, I do not. These witnesses conflate the risk perceptions and return requirements between debt and equity investors. While a lower bond yield spread may indicate that *debt* investors perceive a relatively lower risk in utility bonds (*i.e.*, debt) as compared to Treasury bonds, it does not indicate that *equity* investors perceive utility equity investments as lower risk. Debt investors focus more on stability and predictability of cash flows, timeliness of cost recovery, and probability of defaulting on debt. Equity investors are more concerned with earnings and rate base growth, regulatory support for timely recovery of prudently incurred costs, the strength of the local economy and housing markets, capital spending, changes in interest rates, and long-term weather patterns. As it relates to the allowed ROE for APS, utility credit spreads should not be given any weight.

Q. IS THERE EVIDENCE THAT ECONOMIC POLICY UNCERTAINTY IS HIGHER THAN NORMAL?

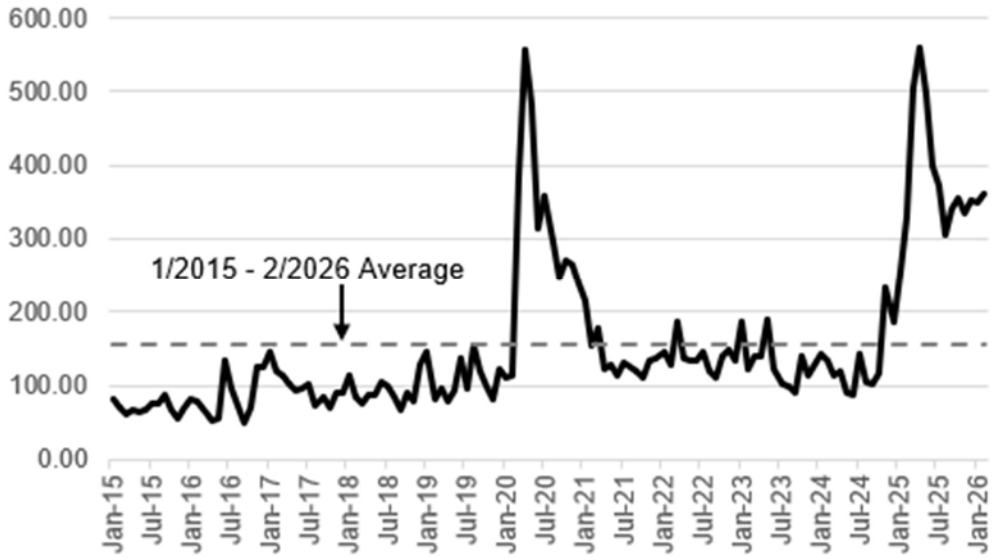
A. Yes, there is. The Federal Reserve Bank of St. Louis publishes an Economic Policy Uncertainty Index (the EPU Index). In the first half of 2025, the EPU Index spiked to levels not seen since the COVID-19 pandemic when President Trump announced changes to U.S. trade policy. While the EPU Index has partially subsided in recent months (to 361.19 as of February 2026), it is still significantly above the average over

[22] Direct Testimony of David C. Parcell, at 11-12, Christopher C. Walters, at 20, 62 and Dr. Zhen Zhu, at 29, 32-33.

the last eleven years (155.57), and this is prior to the conflict in the Middle East. Uncertainty increases risk, which increases the cost of equity, all else equal.

Figure 9: Economic Policy Uncertainty Index

January 1, 2015 – February 27, 2026[23]



Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING HOW CONDITIONS IN THE ECONOMY AND CAPITAL MARKETS ARE IMPACTING THE COST OF EQUITY FOR UTILITIES SUCH AS APS.

A. I see no reason to change the primary conclusion in my Direct Testimony, which was that the cost of capital for both debt and equity has increased for utilities, including APS. This increase is reflected in the results of the models used to estimate the cost of equity. In particular, the DCF model results are higher as utility dividend yields have increased, while the CAPM and Risk Premium results have increased as government bond yields have risen. Although the Federal Reserve has cut the level of short-term interest rates,

[23] Source: Federal Reserve Bank of St. Louis, FRED Economic Database, series USEPUINDXD, https://fred.stlouisfed.org/series/USEPUINDXD/.

yields on long-term government and utility bond yields increased sharply in 2022 and 2023 and have remained elevated as compared to the very low-interest rate environment experienced in the prior decade. Further, core inflation has remained stubbornly above the Federal Reserve's target level of 2.0 percent, and tariffs have placed pressure on producer and consumer inflation as companies pass through these duties to end use customers. It is important to recognize that there has been a fundamental change in economic and capital market conditions, and the cost of equity capital for all companies, including utilities, has increased.

VI. PROXY GROUP COMPOSITION

Q. PLEASE SUMMARIZE THE PROXY GROUPS USED BY THE OTHER WITNESSES IN THEIR RESPECTIVE ROE ANALYSES.

A. Most of the other ROE witnesses adopt the same proxy group of companies that I developed in my Direct Testimony for purposes of estimating the cost of equity for APS in this proceeding. However, Staff witness Parcell and RUCO witness Zhu use their own set of screening criteria to develop their proxy groups for APS. In my opinion, the companies in Mr. Parcell's proxy group are less comparable to APS in terms of business and financial risk than are the companies in my proxy group. In particular, Mr. Parcell's proxy group contains fewer companies, and many of the companies he selected do not own regulated nuclear generation, are not exposed to significant wildfire risk, and have not implemented formula rates or do not operate under a multi-year rate plan. Although Dr. Zhu has used somewhat different screening criteria than mine to develop his proxy group, the companies he ultimately selects are similar to my proxy group.

Q. PLEASE DESCRIBE THE SCREENING CRITERIA MR. PARCELL HAS USED TO SELECT HIS PROXY GROUP.

A. Mr. Parcell's screening criteria are described on page 26 of his Direct testimony, and results in his proxy group of eight companies as shown in Schedule 6 of his exhibits. They include the following criteria:

1. Primarily an electric utility in the U.S.
2. Market cap of $25 billion or less.
3. Common equity ratio of 40 percent or greater.
4. Value Line Safety of 1 or 2.
5. Moody's or S&P bond ratings of A or Baa/BBB.
6. Currently pays dividends, and has not reduced dividends in the past five years, and
7. Not recently in a major merger or asset divestiture.

Q. DO YOU AGREE WITH MR. PARCELL'S AND DR. ZHU'S INCLUSION OF PNW IN THE PROXY GROUP FOR APS?

A. No, I do not. As explained in my Direct Testimony, it is customary to exclude the subject company, or its parent holding company, from the proxy group due to the circular logic that would occur by including those results. If the parent company is included in the proxy group, the market data we rely on for the ROE analysis would reflect the decisions of the regulator as opposed to guiding its decisions, which is the goal of an independent cost of capital analysis. By excluding the parent company, that direct conflict can be avoided.

Q. PLEASE ELABORATE ON THE REASONS WHY YOUR SCREENING CRITERIA RESULT IN A GROUP OF COMPANIES THAT INVESTORS

WOULD VIEW AS MORE COMPARABLE TO APS THAN THE PEER GROUP DEVELOPED BY MR. PARCELL.

A. The screening criteria used by Mr. Parcell to select his proxy group cause him to exclude companies that are similar in business and financial risk to APS. For example, Mr. Parcell excludes several companies that own significant nuclear generation assets, which is an important risk factor for APS. These include: Ameren Corporation; American Electric Power Company; Duke Energy Corporation; Entergy Corporation; NextEra Energy Inc.; Southern Company; and Xcel Energy Inc. Mr. Parcell also excludes several companies that have significant exposure to wildfire risk, which is an important risk factor for APS and its investors. These include: American Electric Power Company and Xcel Energy Inc. Most of these companies failed to pass Mr. Parcell's size related screen, which eliminates companies from the proxy group with market capitalizations of greater than $25 billion. In addition, Mr. Parcell has not provided any evidence regarding whether the companies in his proxy group have regulatory mechanisms that protect them from risks related to fuel and purchased power, volumetric risk, or capital cost recovery, nor has he provided any evidence regarding whether the companies use a historical or forecast test year, or have implemented formula rate plans or operate under multi-year rate plans. As such, there is no evidence from Mr. Parcell concerning the risk profile of the companies in his proxy group, other than their credit ratings.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COMPOSITION OF THE PROXY GROUP FOR APS IN THIS PROCEEDING?

A. While I believe that the companies in my proxy group are more risk comparable to APS than the companies selected by Mr. Parcell, my conclusion is that differences in our respective proxy groups are not the primary driver of the differences in our model results and our ROE recommendations. Therefore, in order to reduce the number of contested issues, I have limited my rebuttal of Mr. Parcell on this issue.

VII. DCF MODEL

Q. PLEASE SUMMARIZE THE OTHER WITNESSES' DCF-BASED ROE ESTIMATES.

A. Figure 10 below summarizes the Other Witnesses' Constant Growth and Multi-Stage[24] DCF estimates.

[24] For purposes of this testimony, I am referring to two-stage, multiple-stage, and non-constant growth DCF models as multi-stage DCF models.

Figure 10: Other Witnesses' DCF Estimates, As Filed

Witness	Constant Growth DCF Results	Multi-Stage DCF Results
Mr. Parcell, Staff[25]	9.50% (Range) 6.90%-9.90%	N/A
Dr. Zhu, RUCO[26]	N/A	9.02% (Range) 7.90%-9.50%
Mr. Ellis, AGO[27]	N/A	6.51%
Mr. Walters, FEA[28]	10.87% & 9.12% (Range) 8.67%-13.47% & 7.52%-12.25%	8.35% (Range) 7.82%-8.97%
Mr. Garrett, LCG[29]	9.0% & 7.10% (Range) 7.0%-12.60% & 6.50%-8.20%	N/A

A. Dividend Yield Calculation

Q. ARE THERE AREAS OF THE DCF ANALYSIS WHERE YOU AND THE OTHER WITNESSES AGREE?

A. Yes. In particular, Staff Witness Parcell's and FEA Witness Walters's approaches to obtain the dividend yield are reasonable, as both rely on current, market-based dividends and average stock prices.[30] I do not agree, however, with the stock-price averaging

[25] Parcell, at 30, Schedule 7. Parcell recommends an overall range of 9.0% to 10.0% percent, with a 9.50% midpoint).

[26] Direct Testimony of Dr. Zhen Zhu Testimony, at 43, Exhibit ZZ-6.

[27] Direct Testimony of Mark E. Ellis, at 7.

[28] Direct Testimony of Christopher C. Walters, at 60, Exhibit CCW-4, Exhibit CCW-7, Exhibit CCW-8. Uses three variants: an analyst EPS growth variant that produces an ROE estimate of 10.87% (range of 8.67%-13.47%), a sustainable growth variant that produces an ROE estimate of 9.12% (range of 7.52%-12.25%), and a multi-stage variant that produces an ROE estimate of 8.35% (range of 7.82%-8.97%).

[29] Direct Testimony of David J. Garrett, at 3, Exhibit DJG-6. Uses two variants: an analyst EPS growth variant that produces an ROE estimate of 9.0% (range of 7.0%-12.6%) and a sustainable growth variant that produces an ROE estimate of 7.10% (range of 6.50%-8.2%).

[30] Direct Testimony of David C. Parcell, at 27-28; Direct Testimony of Chrstopher C. Walters, at 48-49.

conventions applied by Messrs. Ellis, Garrett, and Zhu in their respective dividend yield calculations,[31] and I strongly disagree with Mr. Ellis' assertion that my 90-day and 180-day dividend yield calculations are upwardly biased.[32] The impact of those inputs on the DCF-based ROE estimate, however, is minor as compared to the growth rates applied in the DCF analyses. As discussed below, differences in growth rate estimates are the primary driver of the differences in our respective DCF model results.

B. Growth Rate in Constant Growth DCF Model

Q. PLEASE EXPLAIN WHY YOU DISAGREE WITH THE USE OF GROWTH RATES IN THE DCF MODEL OTHER THAN FORECAST EPS GROWTH RATES FROM EQUITY ANALYSTS.

A, As explained in more detail below, academic research and investor surveys have shown that investors use forecast Earnings per Share (EPS) growth rates from equity analysts in the DCF model because those growth rates have been shown to be the best predictor of future stock prices. As explained in my Direct Testimony the only forward-looking growth rates available on a consensus basis are analysts' EPS growth rates, and investors base their decisions on earnings growth expectations.[33]

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[31] Direct Testimony of Mark E. Ellis, at 51-52, 58; Direct Testimony of David J. Garrett, at 24; Direct Testimony of Dr. Zhen Zhu, at 40.

[32] Direct Testimony of Mark E. Ellis, at 51.

[33] Direct Testimony of James M. Coyne, at 27; See, e.g., Harris and Marston, Estimating Shareholder Risk Premia Using Analysts Growth Forecasts, Financial Management, 21 (Summer 1992), and Vander Weide and Carleton, Investor growth expectations: Analysts vs. history, The Journal of Portfolio Management (Spring 1988, 14 (3)) at 81. Please note that while the original study was published in 1988, it was updated in 2004 under the direction of Dr. Vander Weide. The results of that updated study are consistent with Vander Weide and Carleton's original conclusions.

Mr. Parcell argues that it is improper to rely exclusively on one indicator of growth in the DCF model and that, "investors have an array of information available to them,"[34] and therefore it is reasonable to believe that they consider all of that information in formulating their growth rate expectations. While that may be the case, consensus growth rates or those from Value Line, especially for utilities with highly transparent financial outlooks, provide a reasonable approach to growth estimates. Although Mr. Parcell considers a variety of growth rates including historical retention growth, historical growth in EPS, DPS, and BVPS, projected retention growth, and analysts' projected EPS growth from Value Line and Zacks,[35] only EPS growth rates have been shown to be reliable predictors of future stock prices.

Mr. Walters and Mr. Garrett also present a DCF model using sustainable growth rates.[36] I disagree with their decision to place more weight on their DCF model results which use sustainable growth.[37] Mr. Walters's sustainable growth rate calculation relies on Value Line's projected ROE data for the proxy group companies. Those projected ROEs are substantially higher than the results of the DCF model using sustainable growth rates presented by Mr. Walters, and demonstrate that investors are expecting to earn higher returns on equity from the proxy group companies than what is shown by the DCF model using sustainable growth rates.[38] Mr. Garrett uses a "sustainable" growth rate based on the Congressional Budget Office forecast of GDP growth of 3.7 percent[39],

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[34] Direct Testimony of David C. Parcell, at 29.
[35] Direct testimony of David C. Parcell, at 28-29.
[36] Direct Testimony of Chrstopher C. Walters, at 52-53. Direct Testimony of David J. Garrett, at 24-27.
[37] Direct Testimony of Christopher C. Walters, at 60; Direct Testimony of David J. Garrett, at 26, 28-29.
[38] Direct Testimony of Christopher C. Walters, at CCW-6, CCW-7.
[39] Direct Testimony of David J. Garrett, at Exhibit DJG-5.

which is well below the historic and projected growth rates for utilities. This is not reasonable as an average and it assumes that all companies in the proxy group will grow at the same rate, whereas EPS growth rates estimate from equity analysts are specific to the circumstances of each individual company.

Q. PLEASE EXPLAIN WHY YOU HAVE RELIED ON EPS GROWTH RATES IN THE DCF MODEL RATHER THAN DIVIDEND-BASED OR SUSTAINABLE GROWTH RATES.

A, As discussed in my Direct Testimony, I have relied on EPS growth rates because earnings are the fundamental determinant of a company's ability to pay dividends.[40] As noted by Brigham and Houston:

> Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE).[41]

Academic research supports the use of EPS growth estimates. A 2002 study in the Journal of Accounting Research, examined "the valuation performance of a comprehensive list of value drivers" and found that "forward earnings explain stock prices remarkably well" and were generally superior to other value drivers analyzed.[42] A 2012 study from the journal Contemporary Accounting Research found that the sell-

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[40] Direct Testimony of James M. Coyne, at 26, 27.

[41] Eugene F. Brigham and Joel F. Houston, Fundamentals of Financial Management, page 317 (Concise Fourth Edition, Thomson South-Western, 2004).

[42] Journal of Accounting Research, Jing Liu, Doron Nissim, Jacob Thomas, "Equity Valuation Using Multiples," March 2002.

side analysts with the most accurate stock price targets were those whom the researchers found to have more accurate earnings forecasts.[43]

Investment analysts report predominant reliance on EPS growth projections. In a survey completed by 297 members of the Association for Investment Management and Research, the majority of respondents ranked earnings as the most important variable in valuing a security (more important than cash flow, dividends, or book value).[44] For example, in a December 2023 report on the utility sector, UBS (an investment bank) states: "North American Utilities: Our valuation methodology for the group is price to earnings based."[45]

Q. PLEASE ELABORATE ON WHY YOU DISAGREE WITH THE USE OF GROWTH RATES IN THE DCF MODEL OTHER THAN FORECAST EPS GROWTH RATES FROM EQUITY ANALYSTS.

A. Mr. Parcell considers a variety of growth rates including both historical and projected earnings per share, dividends per share, and book value per share and retention growth. In response to Mr. Parcell's use of historical growth rates and forecast growth rates other than EPS, I agree with Mr. Walters's that "[a]s predictors of future returns, securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data."[46] If Mr. Parcell had relied only on the average analysts'

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[43] Contemporary Accounting Research, Cristi A. Gleason, W. Bruce Johnson, and Haidin Li, "Valuation Model Use and the Price-Target Performance of See-Side Equity Analysts," Spring 2013.

[44] Association for Investment Management and Research, Stanley B. Block, "A Study of Financial Analysts: Practice and Theory," Financial Analysts Journal, July/August 1999.

[45] UBS Global Research and Evidence Lab, 2024 Outlook: A Year for Resolutions and Resolve, December 12, 2023.

[46] Direct Testimony of Christopher C. Walters, at 49.

projected EPS growth rates of 6.2 percent as shown in his Schedule 7, page 4 of 5, the mean DCF results for his proxy group of eight electric utilities would be approximately 10.00 percent, or 20-45 basis points higher than Mr. Parcell's ROE recommendation of 9.80 percent (or 9.55 percent if the FRAM is approved by the ACC) for APS. Likewise, Mr. Walters' Constant Growth DCF model produces an ROE estimate of 10.87 percent based on projected EPS growth rates, as shown in Exhibit CCW-4, page 1.

I also disagree with other witnesses' decisions to place greater weight on the results of their Constant Growth DCF models using sustainable growth rates. I note that both Mr. Parcell's and Mr. Walters's retention growth or sustainable growth rate calculation relies on Value Line's projected ROE data for the proxy group companies, while Mr. Garrett uses projected GDP growth. The projected ROEs from Value Line that Mr. Parcell and Mr. Walters use are substantially higher than the results of the DCF model using sustainable growth rates presented by either Mr. Parcell or Mr. Walters, and demonstrate that investors are expecting to earn higher returns on equity from the proxy group companies than what is shown by the DCF model using sustainable growth rates.

Q. MR. PARCELL AND MR. ELLIS CONTEND THAT ANALYSTS' PROJECTED EPS GROWTH RATES ARE "OVERLY-OPTIMISTIC,"[47] WHILE MR. WALTERS CLAIMS THAT LONG-TERM GDP GROWTH SERVES AS A CAP ON LONG-TERM EPS GROWTH RATES AND SUGGESTS THAT SHORT-

[47] Direct testimony of David C. Parcell, at 31, and Direct Testimony of Mark E. Ellis, at 84.

TERM EPS GROWTH RATES ARE TOO HIGH.[48] DO YOU SHARE THOSE CONCERNS?

A. No, I do not. Analysts covering the common stock of the proxy companies certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation. Thus, it is unclear why investors would assume that the proxy companies are susceptible to an upward bias in earnings projections, especially given the fact that electric utilities operate in an industry with a very high degree of financial transparency due to their regulation.

Likewise, actual earnings data belie Mr. Walters's position that projected GDP growth represents a cap on long-term EPS growth. The suggestion that equity earnings are limited by future growth in GDP may hold for aggregate corporate earnings in a closed economy, but these are not realistic assumptions for an individual firm nor for utilities in general.[49]

No company, or investor, would be satisfied with growth that simply tracks the broader economy. Investors would shift capital to more attractive investments. Companies are constantly searching for new avenues of growth and have levers such as capital resource allocation to achieve growth greater than GDP. There is no reason to expect that an individual corporation competing for capital as a going concern will limit earnings or dividend growth to GDP. In my opinion, limiting growth in the DCF model to long-term GDP is an unfounded constraint. Therefore, I do not share Mr. Walters's concern

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[48] Direct Testimony of Christopher C. Walters, at 51-52.

[49] See MSCI Barra Research Bulletin, Is There a Link Between GDP Growth and Equity Returns? (May 2010).

that analysts' projected EPS growth rates are unsustainable or Mr. Parcell's concern that they are overly optimistic. The average EPS growth rate that Mr. Walters uses in his Constant Growth DCF model (i.e., 7.37 percent)[50] are almost exactly the same as those used in my updated Constant Growth DCF analysis (i.e., 7.31 percent)[51].

C. Use of Multi-Stage Model and Terminal Growth Rate

Q. MR. ELLIS, MR. WALTERS, AND DR. ZHU ALL RELY ON OR CONSIDER THE RESULTS OF MULTI-STAGE DCF MODELS. DO YOU HAVE CONCERNS WITH THOSE APPROACHES IN THIS PROCEEDING?

A. Yes, I have several concerns. In general, the Constant Growth form of the DCF model is appropriate for purposes of estimating the ROE for regulated utilities, whereas a Multi-Stage DCF model is best suited for companies that are in the early growth stages, during which time they may be growing faster than in later years, when the company enters the mature stage. Mr. Walters cites academic literature describing the Constant-Growth DCF model as appropriate for mature companies with stable growth expectations,[52] but nevertheless places "considerable weight" on sustainable-growth and Multi-Stage DCF models based on the premise that analyst growth rates exceed long-term GDP.[53] Mr. Ellis similarly constrains long-term growth to the rate of inflation in his Multi-Stage DCF analysis,[54] and Dr. Zhu relies on a Multi-Stage framework that transitions to a GDP-based terminal growth rate.[55] While these witnesses rely on

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50 Direct Testimony of Christopher C. Walters, at Exhibit CCW-4.
51 Rebuttal Testimony of James M. Coyne, at Attachment JMC-3RB.
52 Direct Testimony of Christopher C. Walters, at 56.
53 *Ibid*., at 60.
54 Direct Testimony of Mark E. Ellis, at 56-57.
55 Direct Testimony of Dr. Zhen Zhu, at 42.

macroeconomic constraints to limit long-term growth, they do not identify a change in business conditions that would require staged downward growth for a mature, regulated utility. A Constant Growth DCF framework is therefore more consistent with their own characterization of the industry. If anything, current evidence points toward a stage of accelerated growth for the industry.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE TERMINAL GROWTH RATES USED BY MR. ELLIS AND MR. GARRETT.

A. My primary concern with the terminal (or long-term) growth rates used by Mr. Ellis and Mr. Garrett is that they understate the long-term growth of utility earnings and in particular the potential earnings growth of a company such as APS, which provides service where the economy is expanding. For example, Mr. Ellis's multi-stage DCF model applies a terminal growth rate equal to expected inflation, which he estimates at 1.87 percent using Treasury-TIPS spreads.[56] This terminal growth assumption is based on long-term historical utility dividend performance and, by construction, does not incorporate any real growth component. This growth rate is extraordinarily low, and well below the forecast GDP growth rate of 4.24 percent from Blue Chip Financial Forecasts for the period from 2027-2031.[57] In addition, the compound annual growth rate for projected GDP growth is 5.47 percent based on real GDP growth of 3.17 percent from 1929-2025 and projected inflation of 2.18 percent.[58] As a result of his extraordinarily low GDP growth rate estimate, Mr. Ellis' Multi-Stage DCF model

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[56] Direct Testimony of Mark E. Ellis, at 56-58.
[57] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14.
[58] GDP growth rate data from Bureau of Economic Analysis, projected inflation rate from Blue Chip Financial Forecasts and Energy Information Administration.

produces return estimates ranging from 5.78 percent to 7.33 percent,[59] which are unreasonable by any standard. These Multi-Stage DCF results do not reflect ongoing customer, load, and rate base growth for APS, and produce ROE estimates well below those authorized for comparable integrated electric utilities, which have averaged approximately 9.86 percent since January 2024.[60]

Mr. Garrett's DCF analysis applies a terminal growth rate that is capped at nominal GDP, which he estimates at 3.7 percent based on the Congressional Budget Office's long-term forecast.[61] Mr. Garrett justifies this assumption on the premise that regulated utilities operate in defined service territories and therefore cannot achieve long-term growth in excess of the overall economy.[62] Again, this growth rate is extraordinarily low, and well below the current forecast GDP growth rate of 4.24 percent from Blue Chip Financial Forecasts for the period from 2027-2031[63] and the historical level of GDP growth of approximately 5.5 percent. By construction, Mr. Garrett's terminal growth assumption does not incorporate any real growth beyond general economic expansion, notwithstanding APS's significant customer, load, and rate base growth in Arizona.

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59 Direct Testimony of Mark E. Ellis, at 59.
60 Source: Regulatory Research Associates.
61 Direct Testimony of David J. Garrett, at 28.
62 *Ibid*.
63 Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 14.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE LONG-TERM GROWTH RATE FOR APS COULD BE HIGHER THAN GDP GROWTH FOR A SUSTAINED PERIOD.

A, As discussed in my Direct Testimony, APS provides service in a territory that is benefiting from population growth through migration, and load growth through demand from large industrial customers and data centers.[64] APS's capital spending plan is impacted by population growth and economic growth in Arizona, both of which have generally trended above the nationwide average, which leads to increased demand for electricity. As shown in **Error! Reference source not found.** of my Direct Testimony, Arizona's growth in state domestic product has exceeded real GDP growth in the U.S. in most quarters since before the COVID-19 pandemic. This evidence demonstrates that the terminal growth rates used by Messrs. Ellis and Garrett in particular likely understate the long-term growth potential of regulated utilities such as APS. Consequently, this causes the results of their Multi-Stage DCF models to understate the cost of equity for APS.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGRADING THE DCF MODEL RESULTS PRESENTED BY THE OTHER WITNESSES.

A. With the exception of the Constant Growth DCF results presented by Mr. Parcell and Mr. Walters that are based on analysts' projected EPS growth rates, the DCF model results of the other ROE witnesses understate the cost of equity for APS. This is due primarily to unreasonably low growth rates that are inconsistent with investor

[64] Direct Testimony of James M. Coyne, at 20, 38.

expectations for the electric utility industry generally, or APS in particular. For the reasons discussed throughout this section, I disagree with the use of dividend growth, sustainable growth, book value growth, and historical growth rates in the DCF model.

VIII. CAPM ANALYSIS

Q. PLEASE SUMMARIZE THE CAPM RESULTS OF THE OTHER WITNESSES AND PROVIDE YOUR COMMENTS ON WHETHER THOSE RESULTS ARE REASONABLE COST OF EQUITY ESTIMATES FOR APS.

A. Figure 12 below summarize the CAPM estimates of the other ROE witnesses.

Figure 12: Other Witnesses' CAPM Estimates, As Filed

Witness	CAPM Range of Mean Results	CAPM-based ROE Estimate
Mr. Parcell, Staff[65]	9.20%-10.20%	9.60%
Dr. Zhu, RUCO[66]	7.88%-9.60%	8.46%
Mr. Ellis, AGO[67]	5.31%-5.81%	5.53%
Mr. Walters, FEA[68]	8.45%-11.20% 8.62%-11.49% 6.72%-8.15% 7.56%-9.63%	9.71% 9.93% 7.36% 8.50%
Mr. Garrett, LCG[69]	8.0%-9.3%	8.50% & 7.90%

[65] Direct Testimony of David C. Parcell, at 36, Exhibit DCP-1 Schedule 9.
[66] Direct Testimony of Dr. Zhen Zhu, at
[67] Direct Testimony of Mark E. Ellis, at 89.
[68] Direct Testimony of Christopher C. Walters, at 81-82, Exhibit CCW-16. The ranges reflect the application of alternative risk-free rates and market risk premium estimates using the proxy group beta estimates reported by Value Line and S&P Global Market Intelligence. See Exhibit CCW-16.
[69] Direct Testimony of David J. Garrett, at Exhibit DJG-11, Exhibit DJG-12 (7.90% is Garrett's Hamada CAPM estimate).

From the outset, it is evident that Mr. Ellis' 5.53 percent CAPM estimate fails the test of economic logic. No rational investor would accept a ROE that is below the return that they could receive on debt by investing in safer utility bonds that have a priority claim on earnings ahead of equity shareholders. As such, results that are so implausibly low should be given no weight. Also, as a preliminary matter, Mr. Parcell incorrectly claims that I relied on an Empirical CAPM ("ECAPM") analysis in my Direct Testimony.[70] I did not introduce or apply an ECAPM in this proceeding, and my CAPM results are based solely on the traditional CAPM framework.

A. Risk-Free Rate

Q. BOTH DR. ZHU AND MR. ELLIS OBJECT TO YOUR USE OF A FORECAST 30-YEAR TREASURY YIELD AS THE RISK-FREE RATE, ARGUING THAT COST-OF-CAPITAL MODELS SHOULD RELY ONLY ON CURRENT MARKET RATES. HOW DO YOU RESPOND?

A. I disagree. As explained in my Direct Testimony, the CAPM model is forward-looking, and using a long-term forecast of the 30-year Treasury bond yields as the risk-free rate in the CAPM appropriately reflects the market's expectations for forward-looking interest rates.[71] Under current market conditions, however, the 30-day average yield on 30-year Treasury bonds as of February 27, 2026 of 4.79 percent is similar to the long-term forecast from Blue Chip of 4.60 percent for 2027-2031. While I continue to support the use of a projected Treasury bond yield as the risk-free rate at the theoretical level, from a practical perspective the use of the current average yield on Treasury bonds

[70] Direct Testimony of David C. Parcell, at 37.
[71] Direct Testimony of James M. Coyne, at 28, 30.

produces a similar, albeit slightly higher, CAPM estimate. In other words, my CAPM estimates would be slightly higher if I had used the current average Treasury bond yield as the risk-free rate, as Dr. Zhu and Mr. Ellis suggest.

B. Beta Coefficients

Q. HOW DO THE INTERVENOR WITNESSES ESTIMATE BETA COEFFICIENTS?

A. Staff Witness Parcell relies on the most recent Value Line beta estimates for the proxy group companies.[72] Mr. Garrett also relies on Value Line published betas.[73] Dr. Zhu relies on Bloomberg betas derived from five-year regressions against the S&P 500, and rejects the use of Value Line betas.[74] Mr. Walters evaluates several beta estimates, including current and historical Value Line betas, three-year adjusted betas, and Vasicek-adjusted betas, and places greater emphasis on Vasicek-adjusted beta estimates.[75] Mr. Ellis calculates five-year trailing monthly betas based on excess returns, and explicitly rejects Value Line betas, weekly betas, and longer regression periods.[76]

Figure 13 below summarizes the beta estimates of the other ROE witnesses.

[72] Direct Testimony of David C. Parcell. At 34.
[73] Direct Testimony of David J. Garrett, at 32-33.
[74] Direct Testimony of Dr. Zhen Zhu, at 46-47.
[75] Direct Testimony of Christopher C. Walters, at 74-75, Exhibit CCW-14.
[76] Direct Testimony of Mark E. Ellis, at 69, 71-73.

Figure 13: Other Witnesses' Beta Estimates

Witness	Beta	Source	Reference
Mr. Parcell, Staff	0.76	Value Line	DCP-1, Sch. 9
Dr. Zhu, RUCO	0.62	Bloomberg	Exhibit ZZ-8
Mr. Ellis, AGO	0.66	Based on his calculations	Testimony, pg. 7, Figure 1
Mr. Walters, FEA	0.75 0.78 0.57 0.40	Value Line current Value Line LT avg 3 yr adjusted VL method 5 yr Vasicek adjusted	CCW-15 and CCW-16
Mr. Garrett, LCG[77]	0.75	Value Line	Exhibit DGJ-8

Q. DR. ZHU, MR. WALTERS, AND MR. GARRETT ASSERT THAT YOUR BETA INPUTS ARE OUTDATED OR BIASED UPWARD BECAUSE THEY INCLUDE COVID-ERA VOLATILITY.[78] WHAT IS YOUR RESPONSE?

A. The analysis in my Direct Testimony was based on market data as of March 31, 2025. As such, the Bloomberg betas based on five years of weekly data did not include the period of COVID-era volatility, most of which occurred in February and March of 2020. However, the Value Line betas may have included these months because Value Line publishes reports for electric utilities on a rolling basis by region. I have updated my ROE analysis based on market data as of February 27, 2026, as part of my Rebuttal Testimony. The updated CAPM results reflect current 5-year weekly betas from Value Line and Bloomberg, which do include the period of COVID. I have continued to

[77] Mr. Garrett's Value Line beta is 0.75, and his unlevered beta for the Hamada equation is 0.36.
[78] Direct Testimony of Dr. Zhen Zhu, at 68; Direct Testimony of Christopher C. Walters, at 91-92; Direct Testimony of David J. Garrett, at 41-43.

include Bloomberg betas calculated over a 10-year period as well, because those longer time periods generally tend to be more representative of long-term industry trends.

Five-year average adjusted betas from Bloomberg and Value Line (Value Line only reports adjusted betas) for electric and gas utilities generally ranged from 0.80 to 0.90 from early 2020 to early 2025. While those betas have declined in the past year as the early months of the COVID pandemic are no longer included in the calculation, I disagree with Mr. Eliis' claim "that a ten-year trailing history is not representative of current market conditions."[79] The 10-year betas from Bloomberg pre-date the COVID-19 period, which suggests that the proxy group beta coefficients are being affected by factors other than the pandemic. In my view, both a 5-year estimate of beta as well as a 10-year estimate of beta is information an investor would reasonably consider in developing a CAPM-based estimate of the cost of equity. Much like any particular model, there is no single measure of beta that is appropriate at all times under all market conditions. As such, it is appropriate to consider multiple inputs as well as multiple models.

Q. HOW DO YOU RESPOND TO CRITICISM OF VALUE LINE BETAS FROM DR. ZHU AND MR. ELLIS?

A. As explained in my Direct Testimony, I did not rely on a single beta estimate, but instead considered multiple market-based beta measures for the proxy group, including Value Line betas and Bloomberg-calculated betas using both five-year and ten-year

[79] Direct Testimony of Mark. E. Ellis, at 71.

regression periods.[80] Value Line's reported beta coefficients are widely used by cost of equity witnesses, including Mr. Parcell, Mr. Walters, and Mr. Garrett, and have been accepted by regulatory commissions for decades. Bloomberg's beta coefficients are similarly widely used and accepted by investors and industry practitioners.

Q. MR. ELLIS CLAIMS THAT THE "ADJUSTED" BETAS USED IN YOUR CAPM ANALYSIS ARE NOT VALID FOR UTILITIES.[81] HOW DO YOU RESPOND?

A. In my experience, regulators across the U.S. rely on adjusted betas from sources such as Value Line and Bloomberg. Further, academic research supports the use of adjusted betas. Specifically, Professor Marshall Blume studied four groups of betas, ranging from a very low beta group (averaging 0.50, and similar to the utility industry) to a very high beta group, and he found that his proposed adjustment best predicted future betas for each of the four risk groups over the next seven years. Dr. Blume found that a low beta portfolio that averaged 0.50 migrated towards the grand mean of all betas of 1.0 approximately in accordance with the Blume formula. The study demonstrates that betas migrate towards the market mean of 1.0 and do indeed exceed their long-term unadjusted averages. Given that the ROE analysis is intended to estimate the forward-looking cost of capital, it is important that the CAPM analysis reflects a forward view of beta and its tendency to move toward the market mean over time.[82]

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[80] Direct Testimony of James M. Coyne, at 30.
[81] Direct Testimony of Mark E. Ellis, at 71-72.
[82] See Marshall E. Blume, *On the Assessment of Risk, The Journal of Finance, Vol. XXVI, No. 1* (March 1971) and Marshall E. Blume, *Betas and Their Regression Tendencies, The Journal of Finance, Vol. XXX, No. 3* (June 1975), where Blume found that there was strong evidence that Beta regressed toward the market mean, and that tendency was strongest in the case of the lowest risk portfolios.

Q. DO YOU HAVE SIMILAR CONCERNS WITH MR. WALTERS'S USE OF VASICEK ADJUSTED BETAS?

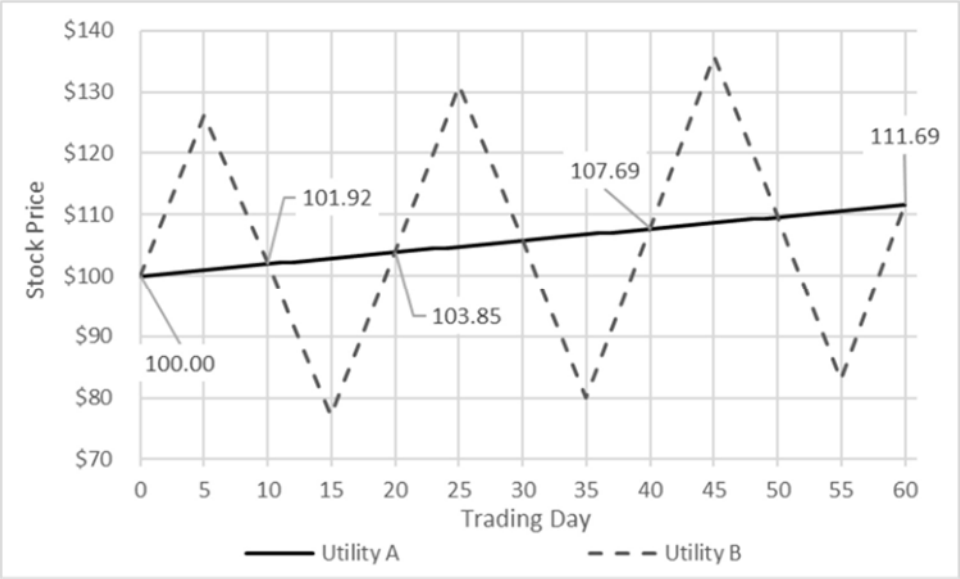
A. Yes, I do. Vasicek-adjusted betas assume that betas for the proxy group companies revert to the industry mean rather than the average for the broad market of 1.0. This is not consistent with the findings of Dr. Blume, and it overlooks the periods when utility companies have traded in line with the broad market, such as during the COVID-19 pandemic and the financial crisis of 2007-2009. Utilities are not always perceived as defensive, low risk investments. The Blume methodology for adjusting beta better reflects the approach used by both investors and regulators for the utility industry in contrast to the Vasicek method.

Q. DO YOU AGREE WITH MR. ELLIS' CLAM THAT "FIVE-YEAR MONTHLY BETAS SHOULD BE USED TO ESTIMATE LONG TERM COE"?[83]

A. No. I do not agree. By their nature, betas calculated using monthly returns do not capture intra-month return volatility and could lead one to conclude that utility stock returns are more stable than they actually are. Consider, for example, stock prices for two utilities – Utility A and Utility B – over a 60-trading day period (roughly three calendar months), illustrated in Figure 14 below. Both utilities start trading at a price of $100 per share. Both utilities report a stock price return of 11.69 percent at the end of three months. At the end of every month (the 20th trading day), both stocks have the same price. However, Utility B's stock price is clearly more volatile (and therefore riskier) than Utility A's.

[83] Direct Testimony of Mark E. Ellis, at 69-70

Figure 14: Illustrative Example of Weekly vs. Monthly Stock Volatility



If the beta coefficient for Utility B were calculated using monthly returns, it would not capture intra-month stock price volatility, and Utility B's beta coefficient would be the same as Utility A's. On the other hand, if the beta coefficients were calculated using weekly returns (every five trading days), Utility B's beta coefficient would be higher than Utility A's, all else equal, better reflecting its higher volatility. In other words, Mr. Ellis' proposal to use monthly return data is asking the Commission to ignore evidence of higher volatility and risk that is captured through the use of weekly return data.

C. Market Risk Premium

Q. SOME INTERVENOR WITNESSES CHALLENGE THE FORWARD-LOOKING MARKET RISK PREMIUM YOU HAVE USED IN YOUR CAPM ANALYSIS.[84] CAN YOU PLEASE RESPOND TO THEIR CONCERNS?

A. The method I have used to calculate the forward-looking MRP is similar to the methodology used by FERC in Opinion No. 531-B.[85] Specifically, the forward-looking MRP in my CAPM analysis is derived by calculating the expected total return for the companies in the S&P 500 Index less the projected risk-free rate. Dr. Zhu adjusts my forward-looking MRP to exclude companies with negative growth rates and growth rates above 20 percent.[86] However, when investors purchase the S&P 500 Index or a mutual fund or exchange traded fund that mirrors the S&P 500 Index, their total return is based on the returns for all 500 companies in the S&P 500 Index, not only those companies with positive EPS growth rates or growth rates less than 20 percent. Further, my MRP calculation is internally consistent because the betas used in my CAPM analysis are calculated against all companies in the S&P 500 Index or the NYSE Composite Index, not just against those companies that have positive growth rates or growth rates less than 20 percent.

Several of the other ROE witnesses argue that the total market return used in my forward-looking MRP calculation is not reasonable. To assess its reasonableness, I

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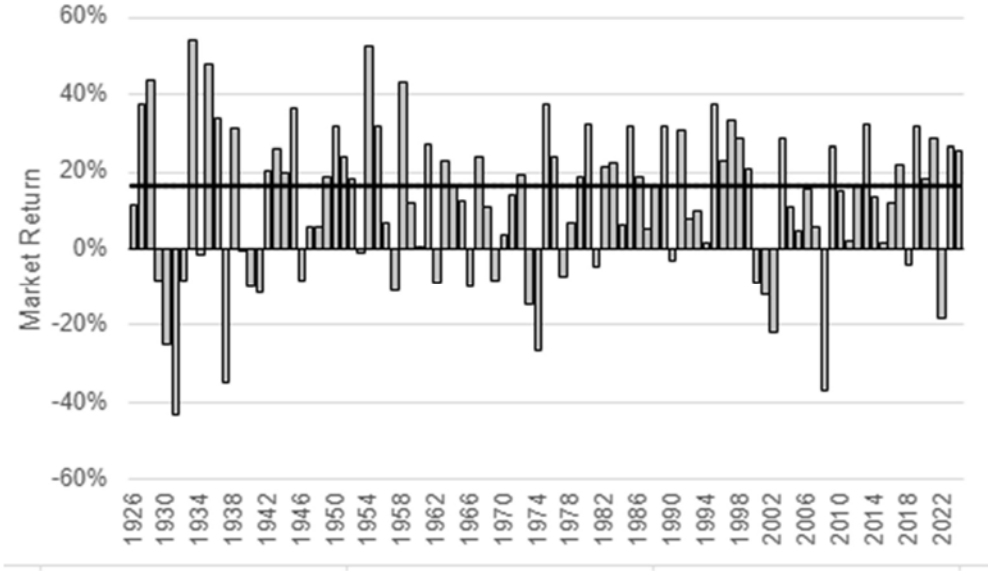
[84] Direct Testimony of David C. Parcell, at 36-37, Direct Testimony of Dr. Zhen Zhu, at 60-61, 62-63, Direct Testimony of Christopher C. Walters, at 91-93, and Direct Testimony of Mark E. Ellis, at 78-79

[85] See MISO Transmission Owners, et al. v. FERC, No. 16-1325 (Aug. 9, 2022) (slip op.) at 17-24 (upholding FERC's CAPM methodology).

[86] Direct Testimony of Dr. Zhen Zhu, at 65.

analyzed the annual performance of the S&P 500 from 1926-2025. As shown in Figure 15 below, the actual return on the S&P 500 Index has exceeded 16.02 percent in 48.00 percent (48 out of 100) of the years from 1926-2025. These data demonstrate that actual total returns for the broad market greater than 16.02 percent are not uncommon.

Figure 15: Total Returns of S&P 500 Index – 1926-2025[87]



Q. PLEASE EXPLAIN YOUR CONCERN WITH THE MARKET RISK PREMIUM APPROACHES USED BY MR. ELLIS AND MR. GARRETT.

A. Mr. Ellis uses a projected market return for the S&P 500 of 5.91 percent less the risk-free rate of 4.80 percent to derive his extraordinarily low market risk premium of 1.11 percent.[88] The average total return for large company stocks (as measured by the S&P 500) has been 12.35 percent from 1926-2025 based on historical return data from Kroll, and the average historical MRP over the same period is 7.37 percent. Mr. Ellis has not offered any explanation regarding why the market return would be more than six

[87] Source: Kroll, Cost of Capital Navigator.
[88] Direct Testimony of Mark E. Ellis, at 7, Figure 1.

percentage points lower (i.e., 12.35 percent vs. 5.91 percent) than the historical average over the past century. As explained in my Direct Testimony, I used both a forward-looking MRP derived from a Constant Growth DCF analysis of the companies in the S&P 500 (the method used by FERC) and a historical MRP based on the Kroll data.

I also disagree with Mr. Garrett's approach to derive his market risk premium of 5.00 percent. Mr. Garrett considers the results of investor surveys, the implied market risk premium calculated by Dr. Damodaran, the projected equity risk premium reported by Kroll, and his own calculation of an implied MRP. As shown in Table DJG-9 of Mr. Garrett's Direct Testimony, these equity risk premia range from 4.4 to 5.5 percent. By contrast, the historical market risk premium reported by Kroll is 7.37 percent based on the average historical return on large company stocks from 1926-2025 less the income only return on 20-year Treasury bonds. Mr. Garrett's MRP estimate of 5.0 percent does not reflect the inverse relationship between interest rates and the equity risk premium. That is, as interest rates decrease (increase), the equity risk premium increases (decreases). My updated CAPM analysis uses a risk-free rate from Blue Chip of 4.60 percent, which is lower than the long-term average Treasury bond yield of approximately 5.00 percent. This indicates that the historical MRP of 7.37 percent from Kroll understates the actual expected MRP under current market conditions. By comparison, Mr. Garrett's 5.00 percent MRP estimate is unreasonably low and should be disregarded by the Commission.

Q. SOME INTERVENOR WITNESSES PREFER THAT THE CAPM RELY ONLY ON HISTORICAL MRP ESTIMATES.[89] HOW DO YOU RESPOND?

A. Sole reliance on the historical MRP is not appropriate under current market conditions because the projected yield on U.S. Treasury bonds is below the long-term historical average yield, and more importantly the projected earnings growth rates for the S&P 500 companies are higher than the historical experience. Equity market returns calculated over the last century do not represent the growth available today to U.S. companies and investors from international markets and the roles of technology and innovation in driving earnings growth.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE CAPM MODEL RESULTS PRESENTED BY THE OTHER WITNESSES.

A. My conclusion is that the CAPM estimate of the other ROE witnesses are understated because they have used unreasonable inputs for the market risk premium and beta. In particular, the CAPM estimates of Mr. Ellis, Mr. Garrett, and Dr. Zhu are substantially lower than the average authorized ROE for integrated electric utilities since 2024. While beta coefficients have declined since the filing of my Direct Testimony, this has been partially offset by a higher risk-free rate and higher market risk premia (both forward-looking and historical). My updated CAPM results continue to support the reasonableness of my 10.7 percent ROE recommendation for APS in this proceeding. The Commission should reject the CAPM estimates presented by Mr. Ellis, Mr. Garrett,

[89] Direct Testimony of David C. Parcell, at 34-36.

and Dr. Zhu as unreasonable compared to returns available to investors in companies with similar risk as APS.

IX. RISK PREMIUM ANALYSIS

Q. MR. ELLIS AND MR. GARRETT CHALLENGE THE RELEVANCE OF THE RISK PREMIUM MODEL. PLEASE SUMMARIZE THEIR CONCERNS.

A. Mr. Ellis has stated three primary concerns regarding my Risk Premium analysis: (1) that it is book-value based, not market-value based; (2) that the analysis perpetuates past regulatory errors rather than measuring investor expectations; and (3) that the methodology has been rejected by FERC.[90] Mr. Garrett argues that there is no benefit to going beyond the CAPM, and that my Risk Premium is based on non-market authorized ROEs going back 30 years, which contradicts my claim that the ROE analysis should be forward-looking.[91]

As a preliminary matter, I note that Mr. Parcell, Dr. Zhu, and Mr. Walters have also used the Risk Premium model to develop a return estimate for APS. Furthermore, numerous U.S. jurisdictions consider the results of the Risk Premium model in establishing the authorized ROE for the utilities under their jurisdiction, including: California, Florida, Georgia, North Carolina, Virginia, West Virginia, and Wisconsin.[92] Academic research also supports the Risk Premium model for public utilities. For example, Dr. S. Keith Barry in a March 1998 article in *Managerial and Decision*

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[90] Direct Testimony of Mark E. Ellis, at 36-38.
[91] Direct Testimony of David J. Garrett, at 44-45.
[92] The Canadian provinces of Alberta and Ontario also set authorized ROEs for electric and gas utilities based on an annual ROE formula that adjusts the authorized ROE based on changes in government bond yields.

Economics titled "Interest Rate Risk and Utility Risk Premia During 1982-1993" identified an inverse relationship between interest rates on utility bonds and the equity risk premium; that same inverse relationship is also demonstrated in my Risk Premium analysis for APS. In addition, a 1995 article in *Financial Management* titled "An Empirical Study of Ex Ante Risk Premiums for the Electric Utilities Industry" found the same inverse relationship between utility equity risk premiums and 30-year Treasury bond yields. The latter article was co-authored by two members of the Division of Economics and Finance at the Virginia State Corporation Commission.

Moreover, in a December 2023 report from UBS on the utility sector, the investment bank presented a regression analysis showing that authorized ROEs at that time were below what would be expected given the historical level of the 10-year Treasury bond yield. Based on the UBS regression equation in that report, and using the 90-day average yield on the 10-year Treasury bond of 4.17 percent as of February 27, 2026, the expected authorized ROE would be 10.64 percent.[93]

Q. PLEASE RESPOND TO MR. ELLIS' CONCERNS WITH THE RISK PREMIUM MODEL.

A. With regard to Mr. Ellis's first concern, my Risk Premium analysis determines the appropriate risk premium based on the relationship between historic authorized ROEs for integrated electric utilities and Treasury bonds yields. While the analysis is not directly based on market data, the authorized ROEs from hundreds of rate case decisions

[93] UBS Global Research and Evidence Lab, US Utilities 2024 Outlook: A Year for Resolutions and Resolve, December 12, 2023, see Figure 10 at page 10.

for electric utilities serve as a relevant benchmark for investors. The regression analysis allows for the estimation of the authorized ROE at varying levels of Treasury bond yields, which addresses Mr. Garrett's claim that my Risk Premium analysis is not forward-looking.

In response to Mr. Ellis's second concern, he essentially argues that regulators have gotten it wrong for more than 30 years, and that my Risk Premium analysis should not be considered in this proceeding because it would perpetuate the regulatory errors of the past. That is an unfounded claim that effectively dismisses the results of 780 electric utility rate decisions by U.S. regulatory commissions spanning the 1992 to 2025 period.

In response to Mr. Ellis's third concern, FERC adopted a similar approach as my Risk Premium analysis as one of its approved methodologies for setting ROEs for electric transmission companies.[94] FERC then reversed that decision in Opinion No. 569-B, but left the door open for utilities to continue presenting a Risk Premium analysis in future proceedings.

Q. MR. PARCELL AND MR. WALTERS CLAIM THAT YOUR RISK PREMIUM ANALYSIS IS FLAWED BECAUSE IT DOES NOT REFLECT CHANGES IN THE REGULATORY ENVIRONMENT FOR UTILITIES SUCH AS INCREASED USE OF ADJUSTMENT CLAUSES AND COST RECOVERY

[94] Federal Energy Regulatory Commission, Opinion No. 569-A, Order on Rehearing, issued May 21, 2020, at para. 105-106 and 108-109.

MECHANISMS IN RECENT YEARS COMPARED WITH THE PERIOD BEFORE THE GREAT RECESSION IN 2008. HOW DO YOU RESPOND?

A. Mr. Parcell and Mr. Walters contend that I have ignored investment risk differentials in my regression analyses, and that my adjustment to the equity risk premium is based exclusively on changes in nominal interest rates. I agree that my analysis is based solely on the relationship between the equity risk premium and interest rates, but with an R^2 of almost 0.80, the relationship to interest rates accounts for approximately 80 percent of the change in awarded ROEs, which is quite strong. To the extent that shifts in industry risk are left out of this equation, the CAPM (and specifically utility betas) would suggest that the Risk Premium results are biased downwards, and likely understate the cost of equity for regulated utilities. This relationship is picked up directly in the CAPM method, and these results are meaningfully higher.

Q. MR. PARCELL, DR. ZHU, AND MR. WALTERS ALSO EXPRESS CONCERNS WITH TIMEFRAME OF YOUR RISK PREMIUM ANALYSIS.[95] PLEASE SUMMARIZE THOSE CONCERNS, AND RESPOND.

A. Several of the other witnesses argue that my Risk Premium analysis does not produce accurate or reliable results because it covers a period from January 1992 through March 2025. These witnesses claim that the relationship between Treasury bond yields and the equity risk premium has changed over this period, and that my analysis does not reflect that change. They refer to this as a "structural break" in the relationship.

[95] Direct Testimony of David C. Parcell, at 43-45, Dr. Zhen Zhu, at 69-70, and Christopher C. Walters, at 94-100.

My response to these witnesses is that my Risk Premium analysis is designed to capture the inverse correlation between Treasury bond yields and the equity risk premium over an extended period of time. The regression equation shown in Attachment JMC-6 enables the model to forecast the authorized ROE for integrated electric utilities at varying levels of Treasury bond yields. In my view, the use of a longer time period is a benefit of my Risk Premium analysis, because this analysis uses decisions from 780 rate case decisions for integrated electric utilities since 1992. My Risk Premium analysis, therefore, is more robust than one that uses data from a shorter time period. In particular, it is ironic that Mr. Parcell makes this criticism of my Risk Premium analysis when he himself discusses economic conditions over a period of 50 years or five business cycles. Given that perspective, I would expect Mr. Parcell to recognize the benefits of using a longer time period in the Risk Premium analysis so as to capture the effect of those business cycles on interest rates and authorized ROEs for electric utilities.

My Risk Premium analysis covers three distinct periods: 1) the relatively high interest rates of the 1990s; 2) the near average interest rates from 2000-2007, and 3) the very low interest rate environment in the decade following the financial crisis, when the Federal Reserve artificially reduced the interest rates on long-term Treasury bonds in order to stimulate the economy through a program known as Quantitative Easing. Of importance to this discussion, when interest rates were last near current levels in the fourth quarter of 2007 to the second quarter of 2008, the average authorized ROE for integrated electric utilities was in the range from 10.54 to 10.65 percent, as shown in Attachment JMC-6DR. This is consistent with the results of my Risk Premium analysis

and demonstrates that the model does not suffer from a "structural break" as some witnesses allege.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE RISK PREMIUM MODEL.

A. The Risk Premium model is highly intuitive and based on the fundamental principle of finance: investors require a measurable premium over a risk-free rate depending on the specific risk of the investment. The CAPM is an extension of the same principle. The Risk Premium model may be critiqued for its simplicity or links to prior regulatory decisions, but those are also strengths and in my view the model provides a valuable compliment to the more complex DCF, CAPM and Expected Earnings models.

X. EXPECTED EARNINGS ANALYSIS

Q. WITH THE EXCEPTION OF STAFF WITNESS PARCELL, THE OTHER ROE WITNESSES OPPOSE THE USE OF AN EXPECTED EARNINGS ANALYSIS TO ESTIMATE THE COST OF EQUITY FOR APS.[96] PLEASE SUMMARIZE THEIR CONCERNS.

A. Mr. Ellis contends that there are a number of issues with the Expected Earnings approach, claiming 1) it does not measure the market cost of equity capital; 2) changes in ROE do not track capital market conditions; 3) the approach is circular; 4) the proxy companies' projected ROEs reflect earnings on business activities that are not representative of APS's rate-regulated electric utility operations; and 5) the Value Line

[96] Direct Testimony of Mark E. Ellis, at 36-40, Direct Testimony of David J. Garrett, at 45-46, Direct Testimony of Christopher C. Walters, at 100-102, and Direct Testimony of Dr. Zhen Zhu, at 71-72.

data used to develop the Expected Earnings analysis is biased upward and reflects the views of only one analyst.[97] Dr. Zhu contends that the Expected Earnings analysis suffers from fundamental flaws. He explains that the analysis relies on Value Line's projected ROEs, which reflect analysts' forecasts of earned returns rather than the minimum return required by investors, and therefore does not measure the market cost of equity that the Commission is charged with determining. Dr. Zhu further notes that Value Line's projected ROEs are based on short-term, three- to five-year analytical frameworks that are not designed to estimate the long-term return required by investors in regulated utility assets, and as a result, may overstate the appropriate authorized ROE for a relatively low-risk, regulated utility such as APS. Mr. Walters contends that the Expected Earnings approach is fundamentally flawed because it relies on accounting-based earned ROEs measured on book value, which do not reflect the return required by investors or the opportunity cost of capital determined by market prices. He further notes that FERC has found the Expected Earnings model does not satisfy the requirements of *Hope* because it fails to identify investments of comparable risk, may be influenced by non-regulated operations, and can produce upward-skewed results. Lastly, Mr. Garrett contends that my Expected Earnings analysis relies on earned returns, which do not measure the forward-looking return required by investors or the cost of equity. He further explains that using expected ROEs to set authorized ROEs creates a circular feedback loop that perpetuates overstated returns.

[97] Direct Testimony of Mark E. Ellis, at 37-43.

Q. WHAT IS YOUR RESPONSE TO THESE CONCERNS?

A, I do not agree with these contentions. The *Hope* and *Bluefield* standards establish that a utility should be granted the opportunity to earn a return that is commensurate with the return on other investments of similar risk. Therefore, it is reasonable to consider the returns that investors expect to earn on the common equity of the electric utility companies in the proxy group as a benchmark. As Dr. Morin notes:

> The Comparable Earnings standard has a long and rich history in regulatory proceedings, and finds its origins in the fair return doctrine enunciated by the U.S. Supreme Court in the landmark Hope case. The governing principle for setting a fair return decreed in Hope is that the allowable return on equity should be commensurate with returns on investments in other firms having comparable risks, and that the allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and ability to attract capital on reasonable terms. Two distinct standards emerge from this basic premise: a standard of Capital Attraction and a standard of Comparable Earnings. The Capital Attraction standard focuses on investors' return requirements, and is applied through market value methods described in prior chapters, such as DCF, CAPM, or Risk Premium. The Comparable Earnings standard uses the return earned on book equity investment by enterprises of comparable risks as the measure of fair return.[98]

The authorized ROE that is established in this case will be applied to the net book value of the Company's rate base (subject to certain regulatory adjustments). In this regard, the Expected Earnings approach provides valuable insight into the opportunity cost of investing in APS's electric utility operations. If investors devote capital to the Company, they forgo the opportunity for that same capital to earn a potentially greater return through investment in the proxy companies.

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[98] New Regulatory Finance, Roger A. Morin Ph.D., Public Utility Reports, 2006, at 381.

In their critiques, Dr. Zhu, Mr. Walters, and Mr. Garrett reject accounting-based earned returns and focus exclusively on market-value measures of investors' opportunity cost of capital, but this diminishes the value of the model's direct test of the Comparable Earnings standard. Investors seek an authorized ROE commensurate with returns on investments of comparable risk.

Q. IS THERE ACADEMIC SUPPORT FOR THE USE OF THE EXPECTED EARNINGS ANALYSIS?

A. Yes, there is. In his text *New Regulatory Finance*, Dr. Roger Morin discusses the strengths and weaknesses of each of the methodologies used to compute the cost of equity. Dr. Morin's conclusion regarding the Expected Earnings analysis is as follows:

> The Comparable Earnings approach is far more meaningful in the regulatory arena than in the sphere of competitive firms. Unlike industrial companies the earnings requirement of utilities is determined by applying a percentage rate of return to the book value of a utility's investment, and not on the market value of that investment. Therefore, it stands to reason that a different percentage rate of return than the market cost of capital be applied when the investment base is stated in book value terms rather than market value terms. In a competitive market, investment decisions are taken on the basis of market prices, market values, and market cost of capital. **If regulation's role was to duplicate the competitive result perfectly, then the market cost of capital would be applied to the current market value of rate base assets employed by utilities to provide service. But because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful.**[99]

[99] New Regulatory Finance, Roger A. Morin Ph.D., Public Utility Reports, 2006, at 394-395. (emphasis added).

In sum, there is a sound basis for application of the Expected Earnings approach to establish the cost of equity for APS.

Q. PLEASE SUMMARIZE MR. WALTERS'S, MR. ELLIS'S, AND MR. GARRETT'S POSITION THAT YOUR EXPECTED EARNINGS ANALYSIS MEASURES BOOK RETURNS, NOT MARKET RETURNS.

A. Mr. Walters argues that my Expected Earnings analysis "should be rejected because this approach does not measure the market required return appropriate for the investment risk of APS. Rather, it measures the book accounting return."[100] Mr. Ellis[101] expresses a similar concern. Mr. Garrett likewise contends that the Expected Earnings approach relies on earned or expected accounting returns. [102] In addition, Mr. Walters contends that "the earned return on book equity is simply not an accurate or legitimate basis upon which to determine a fair and reasonable return on equity for both investors and customers."[103] Mr. Ellis additionally notes that "FERC has rejected the [Expected Earnings analysis]."[104]

Q. WHAT IS YOUR RESPONSE TO THESE CONCERNS?

A. Staff witness Parcell and I agree that the Expected Earnings approach provides an expected return for like-risk companies, which is a core strength of the model and consistent with the basic tenets of *Hope,* which requires that *"*the return to the equity owner should be commensurate with returns on investments in other enterprises having

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[100] Direct Testimony of Christopher C. Walters, at 101.
[101] Direct Testimony of Mark E. Ellis, at 37, 40-42.
[102] Direct Testimony of David J. Garrett, at 45-46.
[103] Direct Testimony of Christopher C. Walters, at 101-102
[104] Direct Testimony of Mark E. Ellis, at 40-43

corresponding risks." Arguably, an investor would consider both current market valuations in deciding between companies of like risk and the value of the expected return on book value. Lastly, in developing his sustainable growth rates for the DCF model, Mr. Walters assumes the reasonableness of the projected returns on equity from Value Line for the proxy group companies, which are the same returns that he dismisses as unreliable in the Expected Earnings analysis. In a similar manner, Mr. Garrett relies on analyst growth assumptions in his DCF analysis, including Value Line's forecasted dividend growth rates for the proxy companies, notwithstanding his rejection of Value Line's projected earned returns for purposes of the Expected Earnings analysis.[105]

Addressing Mr. Ellis's concern with FERC, although FERC has not included the Expected Earnings analysis in its most recent ROE decisions (i.e., Opinion No. 569-B and Opinion No. 594) for electric transmission companies, FERC has left the door open for presentation of an Expected Earnings analysis on a case-by-case basis.[106] In my view, the Expected Earnings analysis provides a valuable picture of the returns that investors are expecting for companies in the Electric Utility sector based on Value Line data. These results are also more stable than those from the DCF and CAPM which shift with more volatile market data. Moreover, as explained in this section, the use of accounting returns is appropriate because the authorized ROE is being applied to an accounting rate base in order to determine the net income a company is authorized to

[105] Direct Testimony of David J. Garrett, at 26, 29, 45-46.

[106] Federal Energy Regulatory Commission, See, e.g., Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc., Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("Opinion No. 569-A").

recover in rates. For all of these reasons, I continue to support the use of the Expected Earnings analysis as one of the models used to estimate the cost of equity.

XI. BUSINESS RISKS

Q. CERTAIN OF THE OTHER ROE WITNESSES CONTEND THAT APS DOES NOT HAVE GREATER THAN AVERAGE BUSINESS RISK BECAUSE THE COMPANY'S CREDIT RATING IS THE SAME AS THE AVERAGE FOR THE PROXY GROUP COMPANIES.[107] THEREFORE, THEY ARGUE THAT APS SHOULD NOT BE AUTHORIZED AN ROE ABOVE THE PROXY GROUP AVERAGE. WHAT IS YOUR RESPONSE?

A. As a preliminary matter, I have not made any adjustment to my ROE recommendation for the greater business risk of APS relative to the proxy group; rather, my ROE recommendation is based on the four-model average results for my proxy group of 10.70 percent. However, I do not agree with the other ROE witnesses that APS's credit ratings of BBB+ (S&P) and Baa1 (Moody's) are an indication that the Company has the exact same business risk as the proxy group companies, at least not from the perspective of an equity investor. As discussed in detail in my Direct Testimony, there are several additional factors that have a direct bearing on APS's risk relative to the proxy group,[108] Among these include APS's:

- relatively high level of capital expenditures,

[107] Direct Testimony of David C. Parcell, at 51, Direct Testimony of Dr. Zhen Zhu, at 80-81, Direct Testimony of Christopher C. Walters, at 104, Direct Testimony of David J. Garrett, at 57-58, and Direct Testimony of Mark E. Ellis, at 34.

[108] Direct Testimony of James M. Coyne, at 37-41, 42-48.

- the regulatory environment in which the Company operates,
- generation risk and in particular ownership of nuclear generation plant, and
- wildfire risk.

On balance, these factors increase APS's risk profile relative to the proxy group and are described in more detail in the Direct Testimony of various APS witnesses.

Furthermore, as also explained in my Direct Testimony, credit rating agencies have recognized that APS's business risk profile is at the low end of its rating category relative to its peers, indicating that APS has greater business risk than its peer group.[109] While acknowledging the recent improvement in the regulatory environment in Arizona, S&P Global states that "Arizona has historically been a challenging regulatory jurisdiction, and we will continue to monitor APS's ability to effectively manage its regulatory risk."[110] With regard to the Company's business risk profile, S&P Global observes that:

> Pressuring our assessment of APS' business risk profile is its limited regulatory diversity, Arizona's historically challenging regulatory construct, exposure to wildfire risk, environmental risks associated with the company's coal-fired generation, and operating risks associated with nuclear generation. As of Dec. 31, 2024, APS owns or leases 6,540 megawatts of generating capacity, about 38.2% of which is from nuclear and coal-fired fuel sources. **We therefore assess APS' business risk profile at the very low end of its category relative to peers. We assess a negative comparable rating analysis modifier that we incorporate in this assessment.**[111]

[109] Direct Testimony of James M. Coyne, at 37-38.
[110] S&P Global Ratings, Arizona Public Service Co., (April 1, 2025) at 3.
[111] S&P Global Ratings, Arizona Public Service Co., (Apr. 1, 2025) at 3. [Emphasis added.]

Q. IS THERE EVIDENCE THAT APS HAS GREATER THAN AVERAGE BUSINESS RISK DESPITE THE IMPROVING REGULATORY ENVIRONMENT IN ARIZONA?

A. Yes, there is. Specifically, one important measure of business risk and the ability of the regulatory environment to mitigate that risk is the utility's ability to earn its authorized ROE. As shown in Figure 16 below, APS has not earned its authorized ROE in any of the years from 2020-2025. The Company has underearned by approximately 1.67 percent on average over this period, and earned approximately 100 basis points below its authorized ROE over the last 12 years.

Figure 16: APS's Earned vs. Authorized ROE[112]

	Earned ROE	Authorized ROE	Earnings differential (bps)
2025 est.	6.3%	9.55%	(325)
2024	8.5%	9.55%	(105)
2023	6.7%	8.90%	(220)
2022	6.8%	8.70%	(190)
2021	9.5%	10.00%	(50)
2020	8.9%	10.00%	(110)
Average	**7.78%**	**9.45%**	**(167)**

[112] Source: Earned ROE data provided by APS in response to data request.

A causal factor in APS's earnings attrition is regulatory lag. Under current practice, the Company must base its rates on allowable expenses and net rate base for a historical test year, which is frequently more than 18 months old by the times new rates go into effect.

Q. STAFF WITNESS PARCELL CLAIMS THAT BECAUSE APS HAS COMPARABLE CREDIT RATINGS TO THE PROXY GROUP, THE COMPANY'S AUTHORIZED ROE SHOULD NOT BE HIGHER THAN THE NATIONAL AVERAGE FOR VERTICALLY-INTEGRATED ELECTRIC UTILITIES. DO YOU AGREE WITH MR. PARCELL ON THIS POINT?

A. No, I do not. The evidence in my Direct Testimony demonstrates that APS has greater than average business risk relative to the proxy group companies, and that risk is exacerbated by the use of a historical test year in Arizona and the length of time after a rate case is filed before new rates take effect.[113] In addition, there is evidence that certain operating companies held by the proxy group have similar business risks as APS but much higher than average authorized ROEs. For example, like APS, Florida Power & Light Company and Georgia Power Co. also own significant amounts of nuclear generation and operate under multi-year rate plans. FPL has an authorized ROE of 11.95 percent on 59.6 percent common equity, and Georgia Power has an authorized ROE of 10.50 percent on 56.0 percent common equity. Both returns are well above the average authorized ROE for integrated electric utilities since January 2024 of 9.86 percent. Several companies in my proxy group are exposed to significant wildfire risk, including Xcel Energy in Texas and Colorado, and American Electric Power in Texas.

[113] Direct Testimony of James M. Coyne, at 42-44.

Credit rating agencies indicate that wildfire risk is an important consideration for APS. APS must compete for capital with these similarly-situated companies, several of which have similar business risk profiles and authorized ROEs above the national average of 9.86 percent.

Q. WHAT IS YOUR CONCLUSION REGARDING APS'S BUSINESS RISK RELATIVE TO THE PROXY GROUP?

A. My conclusion is that APS has greater business risk than the proxy group due to its elevated capital spending program, the requirement to use a historical test year in Arizona, its higher reliance on nuclear generation assets, and its exposure to wildfire related risk. Like the proxy group companies, APS has regulatory mechanisms that mitigate certain business risks. On balance, my risk analysis indicates that APS's business risk is currently greater than the proxy group, although the proposed FRAM (discussed in the next Section) has the potential to mitigate some of this risk differential by reducing the Company's regulatory lag and enhancing its ability to earn its authorized ROE. However, I have not made an adjustment to my ROE recommendation for APS to account for this greater than average business risk; rather, my ROE recommendation is based on the four-model average for the proxy group of 10.7 percent. My updated analysis as of February 27, 2026, demonstrates that the current four-model average is 10.9 percent, which indicates that my recommended ROE for APS is reasonable, if not conservative, under current market conditions.

XII. FORMULA RATE ADJUSTMENT MECHANISM

Q. OTHER ROE WITNESSES RECOMMEND A DOWNWARD ADJUSTMENT OF 15-40 BASIS POINTS TO THEIR ROE RECOMMENDATIONS IF THE ACC ADOPTS THE PROPOSED FRAM. THEY ARGUE THAT THE FRAM REDUCES APS'S BUSINESS RISK AND COMPANY'S REGULATORY LAG, THEREBY ENHANCING THE CHANCE THAT APS WILL EARN ITS AUTHORIZED ROE. WHAT IS YOUR RESPONSE?

A. As discussed in my Direct Testimony, the proposed FRAM, if approved by the Commission, would be credit supportive and bring APS' risk profile in closer alignment with the peer group companies that have a variety of rate mechanisms to address regulatory lag. [114] Under the regulatory compact, APS should have a reasonable opportunity to earn its authorized ROE. The authorized return for APS should not be reduced if the FRAM is approved, as many of the other ROE witnesses recommend, simply because the Company has a better chance to actually earn that authorized return than it has in the past. Rather, this is an opportunity for the Commission to reduce the regulatory lag that has inhibited Arizona utilities from earning their authorized return and to improve investors' perception of the regulatory environment in Arizona, which in the long-term will serve to benefit both customers and the utility through an improved regulatory and credit landscape for Arizona's utilities. A reduction in the authorized ROE of 15-40 basis points due to approval of the proposed FRAM would penalize the Company for implementing a formula rate plan designed to remedy these past problems.

[114] Direct Testimony of James M. Coyne, at 49-50.

Q. HAS THE COMMISSION OUTLINED THE BENEFITS OF FORMULA RATE PLANS FOR ARIZONA'S REGULATED UTILITIES?

A. Yes, APS's response to Staff 11.11 discusses the numerous potential benefits of the proposed formula rate program, as cited by the Commission in its Policy Statement, including:

1. Promoting Gradualism

With the use of annual updates, any increases or decreases are recognized more quickly and are reflected commensurately in the formula. This approach avoids rate shock for customers, which occurs in Arizona's current approach to ratemaking that yields sudden large increase in rates.

2. Savings Passed on to Customers

Changes such as favorable weather revenues, tax reductions, and customer growth are passed on to ratepayers through symmetrical formulas, ensuring that any financial benefits are passed on to customers.

3. Timely and Accurate Cost Recovery

FRPs help utilities recover their costs more quickly, reducing the need for time-consuming rate cases. By enabling annual true-ups, utilities can adjust their rates to reflect actual costs, ensuring that both under- and over-recovery are minimized.

4. Lower Regulatory Burden

With FRPs, utilities and regulators can avoid costly rate cases. This reduction in regulatory processes leads to savings in time, effort, and resources, which ultimately benefits customers through lower utility rates.

5. Improved Financial Efficiency for Utilities

By reducing regulatory lag, FRPs lower financing costs for utilities, which in turn translates into lower rates for customers as there is less interest cost passed through to customers.

6. Facilitating Investment in Critical Infrastructure

For electric, gas, water, and wastewater utilities, FRPs support investments in vital infrastructure, including generation, transmission, and water treatment facilities. These investments ensure the continued delivery of reliable and safe services to customers, including compliance with safety standards and environmental regulations.[115]

Q. SEVERAL OF THE OTHER ROE WITNESSES IMPLY THAT APPROVAL OF THE FRAM WOULD MAKE APS UNIQUE COMPARED TO THE PROXY GROUP COMPANIES. DO YOU AGREE?

A. No, I do not. As shown in Attachment JMC-10DR, approximately 26 percent of the operating companies held by the proxy group have implemented either a formula rate plan or a multi-year rate plan. In Concentric's experience, the trend toward implementation of formula rate plans is likely to continue as both regulators and stakeholders see benefits from stayout periods with appropriate guardrails (e.g., earnings sharing bands and financial monitoring). Approval of the proposed FRAM for APS would align the Company with this trend and with the proxy group companies which have implemented similar rate plans.

As explained in my response to Sierra Club 4.10(b), multi-year rate plans and formula rate plans share common characteristics, most notably an agreement between the utility

[115] https://azcc.gov/news/home/2024/12/06/acc-adopts-formula-rate-plan-policy-statement

and the regulator to stay-out of full rate cases for a certain period; or the utility requests a rate change or the regulator or stakeholders file a complaint challenging the reasonableness of current rates. Both types of plans often employ earnings bands to create efficiency incentives for the utility and protection for customers against over-earnings during the stay-out period. Multi-year rate plans often incorporate pre-determined changes in revenue requirements based on agreed forecasts or measures of inflation, while formula rates are typically designed to track actual costs.

Q. DO YOU AGREE WITH THE OTHER ROE WITNESSES THAT APPROVAL OF APS'S PROPOSED FRAM REDUCES THE COMPANY'S RISK PROFILE?

A. As explained in my response to Staff 11.26, if the FRAM is approved by the Commission, it would make APS more like the operating companies held by the proxy group, many of which already have regulatory mechanisms (such as forecast test years, capital cost recovery mechanisms, CWIP in rate base, etc.) that reduce regulatory lag, and about 26 percent of which have formula rates or operate under multi-year rate plans. The FRAM is designed to address significant regulatory lag in Arizona due to the use of a historical test year for ratemaking purposes. As discussed in Section XI of this Rebuttal Testimony on Business Risk, APS has not been able to earn its authorized ROE in recent years.

In the absence of the proposed FRAM, a higher ROE could be justified, but I have not made an upward adjustment to my ROE recommendation to account for APS's greater business and regulatory risk relative to the proxy group. Furthermore, the proposed FRAM does not mitigate other business risks for APS, including nuclear generation ownership, wildfire risk, elevated capital spending compared to prior years and the

associated execution risk, and customer concentration and data center growth. See Section VII of my Direct Testimony (pages 37-50) for a discussion of these risks for APS relative to the proxy group.

Q. HAS FERC RECENTLY COMMENTED ON WHETHER THE USE OF FORMULA RATES WARRANTS A LOWER ROE?

A. Yes. In Opinion No. 594, FERC addressed the issue of whether the use of formula rates warrants a lower base ROE as follows:

> Similarly, we disagree with arguments that NETOs' [New England Transmission Owners] use of formula rates warrants a lower base ROE. In Opinion No. 551, the Commission found that, similar to the use of more equity in the capital structure, to the extent that formula rates reduce risk, this would be reflected in an improved utility credit rating. Furthermore, the vast majority of proxy group companies also feature formula rates…[116]

Q. WHAT IS YOUR CONCLUSION REGARDING HOW THE PROPOSED FRAM AFFECTS APS'S RISK PROFILE?

A. My conclusion is that the proposed FRAM has the potential to be a constructive regulatory mechanism that balances the interests of the Company and customers. More timely recognition of costs in rates sends customers valuable information regarding their energy costs and allows the Company to better align its cash flow with expenditures. As the program is new and its approval and implementation have yet to unfold, my preliminary view is that the FRAM is credit positive from an investor's standpoint and

[116] Federal Energy Regulatory Commission, Opinion No. 594, issued March 19, 2026, at para. 444. (Clarification added.)

would bring APS's risk profile in closer alignment with the peer group companies that have a variety of rate mechanisms to address regulatory lag. Approval of the FRAM would not cause equity investors to reduce their return requirements for APS because the regulatory compact is intended to give utilities a reasonable opportunity to earn the authorized ROE, whether under formula rates or traditional base rate cases.

XIII. CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE THE CAPITAL STRUCTURE RECOMMENDATIONS OF THE OTHER ROE WITNESSES.

A. Several of the other ROE witnesses support APS's proposed capital structure of 52.35 percent common equity and 47.65 percent long-term debt, which is based on the Company's actual capital structure at the end of its Test Year (the 12-month period ending December 31, 2024). However, Mr. Garrett and Mr. Parcell argue that APS's proposed capital structure includes a significantly higher percentage of common equity relative to the proxy group companies. As a result, they argue that APS has lower financial risk than the proxy group and therefore the authorized ROE should be reduced to reflect its lower financial leverage.[117] Mr. Garrett recommends a reduction in APS's equity ratio to 42.0 percent, while Mr. Parcell recommends a reduction in the Company's authorized ROE to account for the lower financial risk.

[117] Direct Testimony of David C. Parcell, at 51, and Direct Testimony of David J. Garrett, at 51.

Q. PLEASE SUMMARIZE MR. PARCELL'S ANALYSIS OF APS'S PROPOSED CAPITAL STRUCTURE.

A. According to Mr. Parcell, for the period from 2020-2024 the average common equity ratio was in the range of 50.0 percent for the companies in his proxy group and 43.0 percent for the companies in my proxy group,[118] and the average authorized equity ratio for electric utilities has been in a range from 49 to 51percent.[119] The data for the proxy groups in Schedule 5 of Mr. Parcell's exhibits is from Value Line, which reports capital structure data at the holding company level. The average authorized equity ratios for electric utilities is from S&P Global Market Intelligence, and as Mr. Parcell acknowledges, sometimes includes short-term debt and sometimes does not. While Mr. Parcell argues that APS has lower financial risk than the proxy group, he supports the Company's proposed capital structure which contains 52.35 percent common equity.

Q. MR. GARRETT CONTENDS THAT THE AVERAGE COMMON EQUITY RATIO FOR APS SHOULD BE SET AT 42 PERCENT BASED ON HIS ANALYSIS OF THE PROXY GROUP COMPANIES.[120] DO YOU AGREE WITH HIS ANALYSIS?

A. No, Mr. Garrett's analysis is based on data from Value Line, which reports capital structure data at the holding company level rather than the operating company level. As explained in my Direct Testimony, it is appropriate to perform this comparison at the operating utility level because the authorized equity ratio should reflect the business and

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[118] Direct Testimony of David C. Parcell, at 23 and Schedule 5.
[119] *Ibid*, at 24.
[120] Direct Testimony of David J. Garrett, at 51.

operating risks of the utility for which the authorized return is being set.[121] Furthermore, APS has its own credit rating and issues its own debt based on the capital structure of the Company, not that of PNW. As discussed in the Direct Testimony of APS witness Mr. Chris R. Bauer, APS's customers benefit from the Company's stronger S&P credit rating through a lower cost of debt than APS would be able to obtain using the credit rating and capital structure of PNW. APS's proposed capital structure is reasonable because it is based on how the utility is actually capitalized, consistent with the stand-alone principle, which states that the authorized rate of return (i.e., ROE and capital structure) should be based on the risk profile of the company for which the return is being set. Lastly, Mr. Garrett has not performed any type of comparative risk analysis that would suggest that APS has lower business/regulatory risk than his proxy group, nor has he made this assertion in his Direct Testimony. Therefore, there is no reason that APS's common equity ratio would be lower than that of the proxy group companies that are used to set the authorized return. On the contrary, my Direct Testimony demonstrates that APS has greater business risk than the proxy group companies in several important respects.

Q. HAVE YOU UPDATED YOUR CAPITAL STRUCTURE ANALYSIS?

A. Yes. I have updated my capital structure analysis to include the four quarters through Q3 2025 and to remove TXNM, Inc. and Portland General Electric Company from the proxy group. As shown in Attachment JMC-7RB. the mean and median common equity ratios of the proxy group companies are 54.02 percent and 53.43 percent, respectively,

[121] Direct Testimony of James M. Coyne, at 52.

within a range from 48.20 percent to 60.28 percent. That analysis continues to support the reasonableness of APS's proposed 52.35 percent equity in the capital structure.

Q. WHAT IS YOUR CONCLUSION CONCERNING THE APPROPRIATE CAPITAL STRUCTURE FOR APS?

A. I continue to support the reasonableness of APS's proposed capital structure, which includes a common equity ratio of 52.35 percent. This is slightly lower than the updated mean and median equity ratios of the operating utilities held by the proxy group companies. The Commission should reject the recommendation of Mr. Garrett to impute a lower common equity ratio for APS and the recommendation of Mr. Parcell to reduce the Company's authorized ROE to reflect what he claims is APS's lower financial risk relative to the proxy group.

It is important for APS to continue to have access to capital on reasonable terms and conditions for the benefit of both customers and the utility. As discussed in Mr. Bauer's Direct and Rebuttal Testimonies, the Company will have significant external financing requirements to fund its capital investment program. Maintaining APS's financial strength is important so that the Company is able to access capital on reasonable terms under a variety of economic and capital market conditions.

XIV. FAIR VALUE RATE OF RETURN

Q. PLEASE SUMMARIZE THE OTHER WITNESSES' RECOMMENDATIONS RELATED TO THE FAIR VALUE INCREMENT COST RATE.

A. Mr. Parcell recommends a FVI cost rate within the range of 0.00 percent and 0.93 percent as consistent with Arizona's fair value standard. Mr. Walters recommends a

FVI cost rate from 0.00 percent to 0.20 percent. Dr. Zhu, Mr. Ellis, and Dr. McGovern recommend a FVI cost rate of 0.00 percent.

Q. HOW DO YOU RESPOND TO RECOMMENDATIONS TO APPLY NO COST RATE TO THE FAIR VALUE INCREMENT?

A. As discussed in my Direct Testimony, as interpreted by the Arizona Court of Appeals the Article XV, Section 14 of the Arizona Constitution requires that the Commission establish just and reasonable rates using the fair value of the Company's property.[122] Consistent with that, the Commission noted in its decision regarding Chaparral City Water Company that the Arizona Constitution requires the use of a fair value rate base in establishing rates.[123] A FVI cost rate of 0.00 percent fails to reflect an investor required-return on the full equity position in the company's investment. Regardless of the witnesses' interpretation of the Arizona Constitution, a 0.00 percent return effectively rejects the intent of the Arizona Constitution, which allows the utility to earn a return on the FVI of a utility company's rate base. As such, the no cost rate on the FVI increment recommended by Dr. Zhu, Mr. Ellis, and Dr. McGovern is inconsistent with the Arizona Constitution and Commission decisions to authorize a return on the FVI to reflect an investor required-return on the full equity position in the company's investment.

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[122] *In re App. of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges, et al.*, Docket No. E-04204A-15-0142, Decision No. 75697 (Aug. 18, 2016) (Decision No. 75697); *In re App. of UNS Electric, Inc. for Approval of a Rate Increase,* Docket No. E-04204A-09-0206, Decision No. 71914 (Sep. 30, 2010) at 48-49. *See also* Decision No. 70441 at 20-21.

[123] *In re App. of Chaparral City Water Co. for a Determination of the Current Fair Value of Its Utility Plant and Property, et al.*, Docket No. W-02113A-04-0616, Decision No. 70441 (Jul. 28, 2008) (Decision No. 70441) at 20-21.

Q. HOW DO YOU RESPOND TO MR. WALTERS' RECOMMENDATION FOR THE FAIR VALUE RATE OF RETURN?

A. Mr. Walters recommends a FVI cost rate of 0.00 percent to "no higher than" 0.20 percent. Mr. Walter's primary recommendation is that there be no return (i.e., 0.00 percent). However, Mr. Walters acknowledged in the case he cited where the Commission authorized a return on the FVI of 0.00 percent that there was an offsetting adjustment to the authorized ROE to account for an impact of a 0.20 percent return on the FVI.[124] As such, even in the case where the Commission has not included an explicit FVI cost rate, the effect of the FVI has been accounted for elsewhere in the revenue requirement. As to the top end of Mr. Walter's range, he has provided no independent analysis of the reasonableness of a 0.20 percent cost rate, but rather points to other recent authorizations of 0.20 percent in support of his recommendation. As discussed in my Direct Testimony, the range established by the three methodologies that I developed is from 1.94 percent to 2.45 percent and the average is 2.13 percent. Recognizing Commission practice to apply one-half of the real risk-free rate as the return on the fair value increment, I have estimated the real risk-free rate to be 2.13 percent. One-half of that estimate is 1.06 percent. Mr. Walter's recommendation of no higher than 0.20 percent is meaningfully below the estimate of the market-based evidence of the FVI cost rate applying the Commission's past practice.

[124] Direct Testimony of Christopher C. Walters, at 60, Exhibit CCW-6, Exhibit CCW-7, Exhibit CCW-8. Uses three variants: an analyst EPS growth variant that produces an ROE estimate of 10.87% (range of 8.67%-13.47%), a sustainable growth variant that produces an ROE estimate of 9.12% (range of 7.52%-12.25%), and a multi-stage variant that produces an ROE estimate of 8.35% (range of 7.82%-8.97%).

Q. HOW DO YOU RESPOND TO MR. PARCELL'S FAIR VALUE INCREMENT RATE OF RETURN?

A. Mr. Parcell's recommendations range from 0.00 percent to 0.93 percent, with a primary recommendation of 0.00 percent. As noted above, a recommendation of 0.00 percent is inconsistent with the Arizona Constitution and Commission decisions to authorize a return on the FVI to reflect an investor required-return on the full equity position in the company's investment. However, Mr. Parcell provides an analysis similar to what I provided in my Direct Testimony to estimate the real risk-free rate of return. Based on that analysis, Mr. Parcell derives estimates of the real risk-free rate of return of 1.75 percent and 1.95 percent. Taking the average of those two estimates, and applying the Commission's convention of applying one-half of the real risk-free rate of return for the FVI cost rate, Mr. Parcell estimates his maximum value of 0.93 percent. While 0.93 percent is somewhat below the estimate I applied in my Direct Testimony of 1.06 percent, based on Mr. Parcell's updated analysis, the Company is revising its request to 0.90 percent. This falls within Mr. Parcell's range of 0.00 percent to 0.93 percent, which Mr. Parcell concludes "could be applied to the FVI and be consistent with Arizona's fair value standard." [125]

[125] Direct Testimony of David C. Parcell, at 59.

Q. WHAT IS YOUR CONCLUSION AS IT RELATES TO OTHER WITNESSES' RECOMMENDATIONS WITH RESPECT TO THE FAIR VALUE INCREMENTAL RATE OF RETURN?

A. Recommendations of 0.00 percent effectively contradict the intent of the Arizona Constitution, which allows the utility to earn a return on the FVI of a utility company's rate base. The only witness to perform any analysis of the investor required rate of return on the FVI is Mr. Parcell. Based on this analysis, Mr. Parcell recommends a FVI cost rate of up to 0.93 percent. The Company's revised request of 0.90 percent for the FVI rate of return falls within the range of Mr. Parcells' recommendations. In my view, 0.90 percent represents a conservative estimate a reasonable FVI cost rate by applying the Commission's convention of applying one-half of the real risk-free rate of return.

XV. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS IN REBUTTAL.

A. The updated ROE analyses presented in my Rebuttal Testimony continues to support a range of results from 10.20 percent to 11.60 percent from a combination of models and alternative input assumptions. Although the updated analyses indicate that the average of the four models (DCF, CAPM, Risk Premium and Expected Earnings) has increased to 10.90 percent as of February 27, 2026, I continue to recommend an authorized ROE of 10.70 percent for APS. This is a conservative estimate given the updated model results and in light of the business risks of APS relative to the proxy group, combined with my observations pertaining to capital market conditions. I also continue to support the reasonableness of the Company's proposed ratemaking capital structure that

includes a common equity ratio of 52.35 percent. APS has revised its requested rate of return on the FVRB Increment from 1.00 percent to 0.90 percent. This return is reasonable if not conservative for APS, within the range presented by Staff witness Parcell. Nothing in the testimony of the other ROE witnesses has caused me to change my analyses or recommendations.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Summary of ROE Model Results

DCF – 90-day average	**Current**
Constant Growth – Mean	10.60%
Risk Premium – 30 Yr. U.S. Treasury	
2027-2031 forecast	10.56%
CAPM – Forward MRP, Forecast Bond Yield	
Value Line Beta	13.21%
Bloomberg Beta - 5 year	11.37%
Bloomberg Beta - 10 year	13.33%
CAPM – Historical MRP, Current Bond Yield	
Value Line Beta	10.35%
Bloomberg Beta - 5 year	9.16%
Bloomberg Beta - 10 year	10.42%
CAPM average	11.31%
Expected Earnings - Median	11.13%
Mean of All Methods	**10.90%**

PROXY GROUP SCREENING DATA AND RESULTS - FINAL PROXY GROUP

Company	Ticker	[1] Pays Dividends	[2] S&P Credit Rating Between BBB- and AAA	[3] Covered by More Than 1 Analyst	[4] Positive Growth Rates from at least two sources (Value Line, S&P Capital IQ, and Zacks)	[5] Company Owns Generation Assets in Rate Base	[6] % Regulated Revenue > 70%	[7] % Regulated Operating Income > 70%	[8] % Regulated Electric Revenue > 80%	[9] % Regulated Electric Operating Income > 80%	[10] Announced Merger within 180 days from 02/28/26
Alliant Energy Corporation	LNT	Yes	BBB+	Yes	Yes	Yes	98%	98%	85%	85%	No
Ameren Corporation	AEE	Yes	BBB+	Yes	Yes	Yes	100%	100%	85%	84%	No
American Electric Power Company, Inc.	AEP	Yes	BBB+	Yes	Yes	Yes	98%	97%	100%	100%	No
Duke Energy Corporation	DUK	Yes	BBB+	Yes	Yes	Yes	100%	100%	92%	90%	No
Entergy Corporation	ETR	Yes	BBB+	Yes	Yes	Yes	99%	99%	98%	99%	No
Evergy, Inc.	EVRG	Yes	BBB+	Yes	Yes	Yes	100%	100%	100%	100%	No
FirstEnergy Corp	FE	Yes	BBB+	Yes	Yes	Yes	100%	100%	100%	100%	No
IDACORP, Inc.	IDA	Yes	BBB	Yes	Yes	Yes	100%	100%	100%	100%	No
NextEra Energy, Inc.	NEE	Yes	A-	Yes	Yes	Yes	73%	85%	100%	100%	No
OGE Energy Corp.	OGE	Yes	BBB+	Yes	Yes	Yes	100%	100%	100%	100%	No
TXNM Energy, Inc.	TXNM	Yes	BBB	Yes	Yes	Yes	100%	100%	100%	100%	Yes
Portland General Electric Company	POR	Yes	BBB+	Yes	Yes	Yes	100%	100%	100%	100%	Yes
PPL Corporation	PPL	Yes	A-	Yes	Yes	Yes	100%	100%	94%	94%	No
Southern Company	SO	Yes	A-	Yes	Yes	Yes	91%	96%	80%	85%	No
Xcel Energy Inc.	XEL	Yes	BBB+	Yes	Yes	Yes	99%	100%	81%	85%	No

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ
[3] Source: S&P Capital IQ and Zacks
[4] Source: S&P Capital IQ, Value Line Investment Survey, and Zacks
[5] Source: S&P Capital IQ Pro
[6] - [9] Source: Form 10-Ks for 2022, 2023, & 2024, three-year average
[10] SNL Financial News Releases

30-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] S&P Capital IQ Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Mean Low ROE	[10] Overall Mean ROE	[11] Mean High ROE
Alliant Energy Corporation	LNT	$2.14	$68.39	3.13%	3.24%	6.00%	7.65%	7.20%	6.95%	9.22%	10.19%	10.90%
Ameren Corporation	AEE	$2.84	$106.45	2.67%	2.77%	6.50%	8.05%	9.30%	7.95%	9.25%	10.72%	12.09%
American Electric Power Company, Inc.	AEP	$3.80	$123.55	3.08%	3.19%	6.50%	8.20%	6.70%	7.13%	9.68%	10.32%	11.40%
Duke Energy Corporation	DUK	$4.26	$123.25	3.46%	3.57%	6.00%	6.75%	6.90%	6.55%	9.56%	10.12%	10.48%
Entergy Corporation	ETR	$2.56	$99.41	2.58%	2.68%	3.00%	11.00%	11.50%	8.50%	5.61%	11.18%	14.22%
Evergy, Inc.	EVRG	$2.78	$78.68	3.53%	3.66%	7.50%	7.25%	5.90%	6.88%	9.54%	10.54%	11.17%
FirstEnergy Corp	FE	$1.78	$48.18	3.69%	3.81%	5.00%	7.90%	6.50%	6.47%	8.79%	10.28%	11.74%
IDACORP, Inc.	IDA	$3.52	$136.99	2.57%	2.66%	6.00%	7.97%	8.00%	7.32%	8.65%	9.99%	10.67%
NextEra Energy, Inc.	NEE	$2.49	$89.30	2.79%	2.90%	8.00%	8.08%	8.10%	8.06%	10.90%	10.96%	11.00%
OGE Energy Corp.	OGE	$1.70	$45.14	3.77%	3.88%	6.50%	6.30%	5.80%	6.20%	9.68%	10.08%	10.39%
PPL Corporation	PPL	$1.09	$36.74	2.97%	3.08%	7.50%	7.62%	7.30%	7.47%	10.38%	10.55%	10.70%
Southern Company	SO	$2.96	$91.19	3.25%	3.36%	6.50%	7.57%	7.20%	7.09%	9.85%	10.45%	10.94%
Xcel Energy Inc.	XEL	$2.28	$78.21	2.92%	3.04%	7.00%	8.88%	8.90%	8.26%	10.02%	11.30%	11.95%
MEAN				3.11%	3.22%	6.31%	7.94%	7.64%	7.30%	9.32%	10.51%	11.36%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals 30-day average as of February 27, 2026
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: S&P Capital IQ
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] S&P Capital IQ Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Mean Low ROE	[10] Overall Mean ROE	[11] Mean High ROE
Alliant Energy Corporation	LNT	$2.14	$67.22	3.18%	3.29%	6.00%	7.65%	7.20%	6.95%	9.28%	10.24%	10.96%
Ameren Corporation	AEE	$2.84	$103.40	2.75%	2.86%	6.50%	8.05%	9.30%	7.95%	9.34%	10.81%	12.17%
American Electric Power Company, Inc.	AEP	$3.80	$119.92	3.17%	3.28%	6.50%	8.20%	6.70%	7.13%	9.77%	10.42%	11.50%
Duke Energy Corporation	DUK	$4.26	$121.50	3.51%	3.62%	6.00%	6.75%	6.90%	6.55%	9.61%	10.17%	10.53%
Entergy Corporation	ETR	$2.56	$96.07	2.66%	2.78%	3.00%	11.00%	11.50%	8.50%	5.70%	11.28%	14.32%
Evergy, Inc.	EVRG	$2.78	$76.32	3.64%	3.77%	7.50%	7.25%	5.90%	6.88%	9.65%	10.65%	11.28%
FirstEnergy Corp	FE	$1.78	$46.48	3.83%	3.95%	5.00%	7.90%	6.50%	6.47%	8.93%	10.42%	11.88%
IDACORP, Inc.	IDA	$3.52	$131.63	2.67%	2.77%	6.00%	7.97%	8.00%	7.32%	8.75%	10.10%	10.78%
NextEra Energy, Inc.	NEE	$2.49	$84.75	2.94%	3.06%	8.00%	8.08%	8.10%	8.06%	11.06%	11.12%	11.16%
OGE Energy Corp.	OGE	$1.70	$44.38	3.83%	3.95%	6.50%	6.30%	5.80%	6.20%	9.74%	10.15%	10.45%
PPL Corporation	PPL	$1.09	$36.00	3.03%	3.14%	7.50%	7.62%	7.30%	7.47%	10.44%	10.61%	10.76%
Southern Company	SO	$2.96	$90.04	3.29%	3.40%	6.50%	7.57%	7.20%	7.09%	9.89%	10.49%	10.98%
Xcel Energy Inc.	XEL	$2.28	$77.90	2.93%	3.05%	7.00%	8.88%	8.90%	8.26%	10.03%	11.31%	11.96%
MEAN				3.19%	3.30%	6.31%	7.94%	7.64%	7.30%	9.40%	10.60%	11.44%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals 90-day average as of February 27, 2026
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: S&P Capital IQ
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] S&P Capital IQ Earnings Growth	[7] Zacks Earnings Growth	[8] Average Growth Rate	[9] Mean Low ROE	[10] Overall Mean ROE	[11] Mean High ROE
Alliant Energy Corporation	LNT	$2.14	$65.82	3.25%	3.36%	6.00%	7.65%	7.20%	6.95%	9.35%	10.31%	11.03%
Ameren Corporation	AEE	$2.84	$101.60	2.80%	2.91%	6.50%	8.05%	9.30%	7.95%	9.39%	10.86%	12.23%
American Electric Power Company, Inc.	AEP	$3.80	$114.67	3.31%	3.43%	6.50%	8.20%	6.70%	7.13%	9.92%	10.57%	11.65%
Duke Energy Corporation	DUK	$4.26	$121.37	3.51%	3.62%	6.00%	6.75%	6.90%	6.55%	9.62%	10.17%	10.53%
Entergy Corporation	ETR	$2.56	$92.15	2.78%	2.90%	3.00%	11.00%	11.50%	8.50%	5.82%	11.40%	14.44%
Evergy, Inc.	EVRG	$2.78	$73.99	3.76%	3.89%	7.50%	7.25%	5.90%	6.88%	9.77%	10.77%	11.40%
FirstEnergy Corp	FE	$1.78	$44.68	3.98%	4.11%	5.00%	7.90%	6.50%	6.47%	9.08%	10.58%	12.04%
IDACORP, Inc.	IDA	$3.52	$127.79	2.75%	2.86%	6.00%	7.97%	8.00%	7.32%	8.84%	10.18%	10.86%
NextEra Energy, Inc.	NEE	$2.49	$79.53	3.13%	3.26%	8.00%	8.08%	8.10%	8.06%	11.26%	11.32%	11.36%
OGE Energy Corp.	OGE	$1.70	$44.63	3.81%	3.93%	6.50%	6.30%	5.80%	6.20%	9.72%	10.13%	10.43%
PPL Corporation	PPL	$1.09	$35.90	3.04%	3.15%	7.50%	7.62%	7.30%	7.47%	10.45%	10.62%	10.77%
Southern Company	SO	$2.96	$91.71	3.23%	3.34%	6.50%	7.57%	7.20%	7.09%	9.83%	10.43%	10.92%
Xcel Energy Inc.	XEL	$2.28	$75.39	3.02%	3.15%	7.00%	8.88%	8.90%	8.26%	10.13%	11.41%	12.06%
MEAN				3.26%	3.38%	6.31%	7.94%	7.64%	7.30%	9.47%	10.67%	11.52%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals 180-day average as of February 27, 2026
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: S&P Capital IQ
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7])) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7])) + Maximum ([5], [6], [7])

BETA
AS OF FEBRUARY 27, 2026

		[1]	[2]	[3]
		Bloomberg - 5 yr	Bloomberg - 10 yr	Value Line
Alliant Energy Corporation	LNT	0.595	0.750	0.800
Ameren Corporation	AEE	0.615	0.721	0.800
American Electric Power Company, Inc.	AEP	0.529	0.709	0.700
Duke Energy Corporation	DUK	0.504	0.682	0.650
Entergy Corporation	ETR	0.647	0.829	0.750
Evergy, Inc.	EVRG	0.594	0.746	0.750
FirstEnergy Corp	FE	0.559	0.744	0.750
IDACORP, Inc.	IDA	0.548	0.737	0.700
NextEra Energy, Inc.	NEE	0.745	0.795	0.900
OGE Energy Corp.	OGE	0.644	0.868	0.850
PPL Corporation	PPL	0.631	0.896	0.800
Southern Company	SO	0.532	0.741	0.650
Xcel Energy Inc.	XEL	0.568	0.715	0.700
Average		0.593	0.764	0.754

Notes:
[1] - [2] Source: Bloomberg Professional, adjusted beta with five-year and ten-year weekly changes against SPX Index
[3] Source: Value Line

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED VL & BLOOMBERG GROWTH RATES

[1] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.17%
[2] Cap. Weighted Estimate of the S&P 500 Growth Rate	14.77%
[3] Cap. Weighted S&P 500 Estimated Required Market Return	16.02%

STANDARD AND POOR'S 500 INDEX

		[4]	[5]	[6]	[7]	[8]
Name	Ticker	Weight In Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Value Line Long-Term Growth Estimate	Cap. Weighted Long-Term Growth
3M Company	MMM	0.15%	1.89%	0.00%	38.50%	0.06%
A. O. Smith Corporation	AOS	0.02%	1.85%	0.00%	7.50%	0.00%
Abbott Laboratories	ABT	0.34%	2.17%	0.01%	6.50%	0.02%
AbbVie Inc.	ABBV	0.68%	2.98%	0.02%	7.00%	0.05%
Accenture plc	ACN	0.21%	2.98%	0.01%	6.50%	0.01%
Adobe Inc.	ADBE	0.18%	NA	n/a	19.50%	0.03%
Advanced Micro Devices, Inc.	AMD	0.54%	NA	n/a	19.00%	0.10%
Aflac Incorporated	AFL	0.10%	2.16%	0.00%	8.50%	0.01%
Agilent Technologies, Inc.	A	0.06%	0.84%	0.00%	6.50%	0.00%
Air Products and Chemicals, Inc.	APD	0.10%	2.63%	0.00%	4.50%	0.00%
Airbnb, Inc.	ABNB	0.13%	NA	n/a	23.00%	0.03%
Akamai Technologies, Inc.	AKAM	0.02%	NA	n/a	8.00%	0.00%
Albemarle Corporation	ALB	0.04%	0.91%	0.00%	5.50%	0.00%
Alexandria Real Estate Equities, Inc.	ARE	0.02%	5.33%	0.00%	-1.00%	0.00%
Align Technology, Inc.	ALGN	0.02%	NA	n/a	12.00%	0.00%
Allegion plc	ALLE	0.02%	1.29%	0.00%	7.00%	0.00%
Alliant Energy Corporation	LNT	0.03%	2.96%	0.00%	6.00%	0.00%
Alphabet Inc.	GOOGL	6.28%	0.27%	0.02%	18.00%	1.13%
Altria Group, Inc.	MO	0.19%	6.14%	0.01%	6.00%	0.01%
Amazon.com, Inc.	AMZN	3.75%	NA	n/a	23.00%	0.86%
Amcor plc	AMCR	0.04%	5.32%	0.00%	9.50%	0.00%
Ameren Corporation	AEE	0.05%	2.65%	0.00%	6.50%	0.00%
American Electric Power Company, Inc.	AEP	0.12%	2.84%	0.00%	6.50%	0.01%
American Express Company	AXP	0.35%	1.06%	0.00%	11.00%	0.04%
American International Group, Inc.	AIG	0.07%	2.24%	0.00%	16.00%	0.01%
American Tower Corporation	AMT	0.15%	3.54%	0.01%	10.00%	0.01%
American Water Works Company, Inc.	AWK	0.04%	2.43%	0.00%	4.50%	0.00%
Ameriprise Financial, Inc.	AMP	0.07%	1.36%	0.00%	10.50%	0.01%
AMETEK, Inc.	AME	0.09%	0.57%	0.00%	8.50%	0.01%
Amgen Inc.	AMGN	0.35%	2.60%	0.01%	5.50%	0.02%
Amphenol Corporation	APH	0.30%	0.68%	0.00%	18.50%	0.06%
Analog Devices, Inc.	ADI	0.29%	1.24%	0.00%	9.00%	0.03%
Aon plc	AON	0.12%	0.89%	0.00%	11.50%	0.01%
APA Corporation	APA	0.02%	3.29%	0.00%	2.00%	0.00%
Apollo Global Management, Inc.	APO	0.10%	1.95%	0.00%	24.50%	0.02%
Apple Inc.	AAPL	6.46%	0.39%	0.03%	11.50%	0.74%
Applied Materials, Inc.	AMAT	0.49%	0.49%	0.00%	8.50%	0.04%
AppLovin Corporation	APP	0.24%	NA	n/a	53.00%	0.13%
Aptiv PLC	APTV	0.03%	NA	n/a	28.50%	0.01%
Arch Capital Group Ltd.	ACGL	0.06%	NA	n/a	6.50%	0.00%
Archer-Daniels-Midland Company	ADM	0.06%	3.01%	0.00%	1.50%	0.00%
Ares Management Corporation	ARES	0.04%	4.82%	0.00%	31.50%	0.01%
Arista Networks, Inc.	ANET	0.28%	NA	n/a	16.50%	0.05%
Arthur J. Gallagher & Co.	AJG	0.10%	1.23%	0.00%	25.00%	0.02%
Assurant, Inc.	AIZ	0.02%	1.53%	0.00%	9.50%	0.00%
AT&T Inc.	T	0.33%	3.96%	0.01%	6.50%	0.02%
Atmos Energy Corporation	ATO	0.05%	2.14%	0.00%	8.00%	0.00%
Autodesk, Inc.	ADSK	0.09%	NA	n/a	10.50%	0.01%
Automatic Data Processing, Inc.	ADP	0.14%	3.17%	0.00%	6.00%	0.01%
AutoZone, Inc.	AZO	0.10%	NA	n/a	5.50%	0.01%
AvalonBay Communities, Inc.	AVB	0.04%	4.02%	0.00%	6.00%	0.00%
Avery Dennison Corporation	AVY	0.03%	1.91%	0.00%	6.50%	0.00%
Axon Enterprise, Inc.	AXON	0.07%	NA	n/a	31.50%	0.02%
Baker Hughes Company	BKR	0.11%	1.41%	0.00%	19.50%	0.02%
Ball Corporation	BALL	0.03%	1.19%	0.00%	13.50%	0.00%
Bank of America Corporation	BAC	0.60%	2.25%	0.01%	9.00%	0.05%
Baxter International Inc.	BAX	0.02%	0.20%	0.00%	0.00%	0.00%
Becton, Dickinson and Company	BDX	0.08%	2.38%	0.00%	7.50%	0.01%
Berkshire Hathaway Inc.	BRK.A	1.81%	NA	n/a	9.50%	0.17%
Best Buy Co., Inc.	BBY	0.02%	6.13%	0.00%	3.00%	0.00%
Bio-Techne Corporation	TECH	0.02%	0.54%	0.00%	16.00%	0.00%
Biogen Inc.	BIIB	0.05%	NA	n/a	1.00%	0.00%
BlackRock, Inc.	BLK	0.28%	2.16%	0.01%	11.00%	0.03%
Blackstone Inc.	BX	0.15%	5.26%	0.01%	26.00%	0.04%
Block, Inc.	XYZ	0.00%	NA	n/a	NA	n/a
Booking Holdings Inc.	BKNG	0.22%	0.99%	0.00%	14.50%	0.03%
Boston Scientific Corporation	BSX	0.19%	NA	n/a	11.50%	0.02%
Bristol-Myers Squibb Company	BMY	0.21%	4.04%	0.01%	27.50%	0.06%
Broadcom Inc.	AVGO	2.52%	0.81%	0.02%	24.50%	0.62%
Broadridge Financial Solutions, Inc.	BR	0.04%	2.10%	0.00%	9.50%	0.00%
Brown & Brown, Inc.	BRO	0.04%	0.92%	0.00%	11.00%	0.00%
Brown-Forman Corporation	BF.B	0.02%	3.20%	0.00%	7.50%	0.00%
Builders FirstSource, Inc.	BLDR	0.02%	NA	n/a	-3.00%	0.00%
Bunge Global SA	BG	0.04%	2.32%	0.00%	1.50%	0.00%
BXP, Inc.	BXP	0.02%	4.86%	0.00%	1.50%	0.00%
C.H. Robinson Worldwide, Inc.	CHRW	0.04%	1.36%	0.00%	11.50%	0.00%

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED VL & BLOOMBERG GROWTH RATES

[1] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.17%
[2] Cap. Weighted Estimate of the S&P 500 Growth Rate	14.77%
[3] Cap. Weighted S&P 500 Estimated Required Market Return	16.02%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Weight In Index	[5] Estimated Dividend Yield	[6] Cap-Weighted Dividend Yield	[7] Value Line Long-Term Growth Estimate	[8] Cap. Weighted Long-Term Growth
Cadence Design Systems, Inc.	CDNS	0.14%	NA	n/a	12.00%	0.02%
Camden Property Trust	CPT	0.02%	3.91%	0.00%	-6.50%	0.00%
Capital One Financial Corporation	COF	0.20%	1.64%	0.00%	10.00%	0.02%
Cardinal Health, Inc.	CAH	0.09%	0.89%	0.00%	13.00%	0.01%
Carnival Corporation & plc	CCL	0.00%	1.90%	0.00%	NA	n/a
Carrier Global Corporation	CARR	0.09%	1.49%	0.00%	12.00%	0.01%
Carvana Co.	CVNA	0.00%	NA	n/a	NA	n/a
Caterpillar Inc.	CAT	0.58%	0.81%	0.00%	8.50%	0.05%
Cboe Global Markets, Inc.	CBOE	0.05%	0.96%	0.00%	13.00%	0.01%
CBRE Group, Inc.	CBRE	0.07%	NA	n/a	9.00%	0.01%
CDW Corporation	CDW	0.03%	2.05%	0.00%	6.50%	0.00%
Cencora, Inc.	COR	0.12%	0.64%	0.00%	6.50%	0.01%
Centene Corporation	CNC	0.04%	NA	n/a	9.50%	0.00%
CenterPoint Energy, Inc.	CNP	0.05%	2.11%	0.00%	7.00%	0.00%
CF Industries Holdings, Inc.	CF	0.00%	2.01%	0.00%	NA	n/a
Charles River Laboratories International, Inc.	CRL	0.01%	NA	n/a	5.00%	0.00%
Charter Communications, Inc.	CHTR	0.05%	NA	n/a	6.50%	0.00%
Chevron Corporation	CVX	0.62%	3.81%	0.02%	0.50%	0.00%
Chipotle Mexican Grill, Inc.	CMG	0.08%	NA	n/a	15.50%	0.01%
Chubb Limited	CB	0.22%	1.14%	0.00%	9.50%	0.02%
Church & Dwight Co., Inc.	CHD	0.04%	1.17%	0.00%	7.00%	0.00%
Ciena Corporation	CIEN	0.08%	NA	n/a	15.50%	0.01%
Cincinnati Financial Corporation	CINF	0.04%	2.29%	0.00%	9.50%	0.00%
Cintas Corporation	CTAS	0.13%	0.89%	0.00%	13.50%	0.02%
Cisco Systems, Inc.	CSCO	0.52%	2.11%	0.01%	5.50%	0.03%
Citigroup Inc.	C	0.32%	2.18%	0.01%	19.50%	0.06%
Citizens Financial Group, Inc.	CFG	0.04%	3.06%	0.00%	13.00%	0.01%
CME Group Inc.	CME	0.19%	1.63%	0.00%	5.50%	0.01%
CMS Energy Corporation	CMS	0.04%	2.92%	0.00%	8.50%	0.00%
Cognizant Technology Solutions Corporation	CTSH	0.05%	2.05%	0.00%	9.00%	0.00%
Coinbase Global, Inc.	COIN	0.00%	NA	n/a	NA	n/a
Colgate-Palmolive Company	CL	0.13%	2.10%	0.00%	10.00%	0.01%
Comcast Corporation	CMCSA	0.19%	4.26%	0.01%	7.50%	0.01%
Comfort Systems USA, Inc.	FIX	0.08%	0.20%	0.00%	23.50%	0.02%
Conagra Brands, Inc.	CAG	0.02%	7.27%	0.00%	-2.50%	0.00%
ConocoPhillips	COP	0.23%	2.96%	0.01%	-2.00%	0.00%
Consolidated Edison, Inc.	ED	0.07%	3.15%	0.00%	6.00%	0.00%
Constellation Brands, Inc.	STZ	0.05%	2.58%	0.00%	3.50%	0.00%
Constellation Energy Corporation	CEG	0.20%	0.52%	0.00%	21.50%	0.04%
Copart, Inc.	CPRT	0.06%	NA	n/a	8.00%	0.00%
Corning Incorporated	GLW	0.21%	0.74%	0.00%	29.00%	0.06%
Corpay, Inc.	CPAY	0.04%	NA	n/a	13.50%	0.00%
Corteva, Inc.	CTVA	0.09%	0.90%	0.00%	11.00%	0.01%
CoStar Group, Inc.	CSGP	0.03%	NA	n/a	21.50%	0.01%
Costco Wholesale Corporation	COST	0.75%	0.51%	0.00%	11.50%	0.09%
Coterra Energy Inc.	CTRA	0.04%	2.88%	0.00%	3.00%	0.00%
CRH plc	CRH	0.00%	1.27%	0.00%	NA	n/a
CrowdStrike Holdings, Inc.	CRWD	0.00%	NA	n/a	NA	n/a
Crown Castle Inc.	CCI	0.07%	4.75%	0.00%	2.50%	0.00%
CSX Corporation	CSX	0.13%	1.31%	0.00%	8.50%	0.01%
Cummins Inc.	CMI	0.13%	1.37%	0.00%	8.00%	0.01%
CVS Health Corporation	CVS	0.17%	3.33%	0.01%	3.00%	0.01%
D.R. Horton, Inc.	DHI	0.08%	1.12%	0.00%	5.00%	0.00%
Danaher Corporation	DHR	0.25%	0.76%	0.00%	4.50%	0.01%
Darden Restaurants, Inc.	DRI	0.04%	2.81%	0.00%	10.00%	0.00%
Datadog, Inc.	DDOG	0.07%	NA	n/a	21.50%	0.01%
DaVita Inc.	DVA	0.02%	NA	n/a	10.50%	0.00%
Deckers Outdoor Corporation	DECK	0.03%	NA	n/a	11.00%	0.00%
Deere & Company	DE	0.28%	1.03%	0.00%	2.50%	0.01%
Dell Technologies Inc.	DELL	0.16%	1.42%	0.00%	10.50%	0.02%
Delta Air Lines, Inc.	DAL	0.07%	1.14%	0.00%	9.00%	0.01%
Devon Energy Corporation	DVN	0.04%	2.21%	0.00%	-2.00%	0.00%
DexCom, Inc.	DXCM	0.05%	NA	n/a	21.00%	0.01%
Diamondback Energy, Inc.	FANG	0.08%	2.41%	0.00%	-3.00%	0.00%
Digital Realty Trust, Inc.	DLR	0.10%	2.75%	0.00%	9.50%	0.01%
Dollar General Corporation	DG	0.06%	1.51%	0.00%	1.50%	0.00%
Dollar Tree, Inc.	DLTR	0.04%	NA	n/a	22.00%	0.01%
Dominion Energy, Inc.	D	0.09%	4.23%	0.00%	6.50%	0.01%
Domino's Pizza, Inc.	DPZ	0.02%	1.98%	0.00%	14.00%	0.00%
DoorDash, Inc.	DASH	0.00%	NA	n/a	NA	n/a
Dover Corporation	DOV	0.05%	0.92%	0.00%	5.00%	0.00%
Dow Inc.	DOW	0.00%	4.56%	0.00%	NA	n/a
DTE Energy Company	DTE	0.05%	3.14%	0.00%	4.50%	0.00%
Duke Energy Corporation	DUK	0.17%	3.26%	0.01%	6.00%	0.01%
DuPont de Nemours, Inc.	DD	0.00%	1.60%	0.00%	NA	n/a
Eaton Corporation plc	ETN	0.24%	1.12%	0.00%	13.50%	0.03%

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED VL & BLOOMBERG GROWTH RATES

[1] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.17%
[2] Cap. Weighted Estimate of the S&P 500 Growth Rate	14.77%
[3] Cap. Weighted S&P 500 Estimated Required Market Return	16.02%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Weight In Index	[5] Estimated Dividend Yield	[6] Cap-Weighted Dividend Yield	[7] Value Line Long-Term Growth Estimate	[8] Cap. Weighted Long-Term Growth
eBay Inc.	EBAY	0.07%	1.36%	0.00%	14.50%	0.01%
Ecolab Inc.	ECL	0.14%	0.95%	0.00%	8.00%	0.01%
Edison International	EIX	0.05%	4.70%	0.00%	6.50%	0.00%
Edwards Lifesciences Corporation	EW	0.08%	NA	n/a	8.00%	0.01%
Electronic Arts Inc.	EA	0.08%	0.38%	0.00%	11.50%	0.01%
Elevance Health, Inc.	ELV	0.12%	2.15%	0.00%	5.50%	0.01%
Eli Lilly and Company	LLY	1.57%	0.66%	0.01%	29.00%	0.45%
EMCOR Group, Inc.	EME	0.05%	0.22%	0.00%	16.50%	0.01%
Emerson Electric Co.	EMR	0.14%	1.47%	0.00%	14.50%	0.02%
Entergy Corporation	ETR	0.08%	2.39%	0.00%	3.00%	0.00%
EOG Resources, Inc.	EOG	0.11%	3.29%	0.00%	4.00%	0.00%
EPAM Systems, Inc.	EPAM	0.01%	NA	n/a	10.50%	0.00%
EQT Corporation	EQT	0.06%	1.07%	0.00%	9.50%	0.01%
Equifax Inc.	EFX	0.04%	1.07%	0.00%	7.50%	0.00%
Equinix, Inc.	EQIX	0.16%	2.12%	0.00%	15.00%	0.02%
Equity Residential	EQR	0.04%	4.38%	0.00%	4.00%	0.00%
Erie Indemnity Company	ERIE	0.02%	2.17%	0.00%	18.00%	0.00%
Essex Property Trust, Inc.	ESS	0.03%	4.06%	0.00%	6.50%	0.00%
Everest Group, Ltd.	EG	0.02%	2.38%	0.00%	6.50%	0.00%
Evergy, Inc.	EVRG	0.03%	3.32%	0.00%	7.50%	0.00%
Eversource Energy	ES	0.05%	4.13%	0.00%	5.50%	0.00%
Exelon Corporation	EXC	0.08%	3.40%	0.00%	6.00%	0.01%
Expand Energy Corporation	EXE	0.00%	2.13%	0.00%	NA	n/a
Expedia Group, Inc.	EXPE	0.04%	0.89%	0.00%	39.00%	0.02%
Expeditors International of Washington, Inc.	EXPD	0.03%	1.06%	0.00%	1.00%	0.00%
Extra Space Storage Inc.	EXR	0.05%	4.29%	0.00%	-1.00%	0.00%
Exxon Mobil Corporation	XOM	1.06%	2.70%	0.03%	-1.50%	-0.02%
F5, Inc.	FFIV	0.03%	NA	n/a	8.50%	0.00%
FactSet Research Systems Inc.	FDS	0.01%	2.03%	0.00%	6.00%	0.00%
Fair Isaac Corporation	FICO	0.06%	NA	n/a	18.00%	0.01%
Fastenal Company	FAST	0.09%	2.09%	0.00%	10.00%	0.01%
Federal Realty Investment Trust	FRT	0.02%	4.16%	0.00%	2.00%	0.00%
FedEx Corporation	FDX	0.15%	1.50%	0.00%	7.50%	0.01%
Fidelity National Information Services, Inc.	FIS	0.04%	3.45%	0.00%	7.00%	0.00%
Fifth Third Bancorp	FITB	0.07%	3.23%	0.00%	10.00%	0.01%
First Solar, Inc.	FSLR	0.04%	NA	n/a	26.00%	0.01%
FirstEnergy Corp.	FE	0.05%	3.64%	0.00%	5.00%	0.00%
Fiserv, Inc.	FISV	0.06%	NA	n/a	6.50%	0.00%
Ford Motor Company	F	0.09%	4.26%	0.00%	16.50%	0.02%
Fortinet, Inc.	FTNT	0.10%	NA	n/a	12.50%	0.01%
Fortive Corporation	FTV	0.03%	0.41%	0.00%	6.50%	0.00%
Fox Corporation	FOXA	0.04%	0.99%	0.00%	8.00%	0.00%
Franklin Resources, Inc.	BEN	0.02%	4.97%	0.00%	4.00%	0.00%
Freeport-McMoRan Inc.	FCX	0.16%	0.88%	0.00%	18.00%	0.03%
Garmin Ltd.	GRMN	0.08%	1.66%	0.00%	10.00%	0.01%
Gartner, Inc.	IT	0.02%	NA	n/a	5.00%	0.00%
GE HealthCare Technologies Inc.	GEHC	0.00%	0.17%	0.00%	NA	n/a
GE Vernova Inc.	GEV	0.00%	0.23%	0.00%	NA	n/a
Gen Digital Inc.	GEN	0.02%	2.22%	0.00%	8.50%	0.00%
Generac Holdings Inc.	GNRC	0.02%	NA	n/a	20.00%	0.00%
General Dynamics Corporation	GD	0.16%	1.68%	0.00%	12.00%	0.02%
General Electric Company	GE	0.60%	0.55%	0.00%	19.00%	0.11%
General Mills, Inc.	GIS	0.04%	5.39%	0.00%	0.50%	0.00%
General Motors Company	GM	0.12%	0.91%	0.00%	8.50%	0.01%
Genuine Parts Company	GPC	0.03%	3.56%	0.00%	1.50%	0.00%
Gilead Sciences, Inc.	GILD	0.31%	2.20%	0.01%	16.00%	0.05%
Global Payments Inc.	GPN	0.04%	1.31%	0.00%	7.00%	0.00%
Globe Life Inc.	GL	0.02%	0.91%	0.00%	10.00%	0.00%
GoDaddy Inc.	GDDY	0.02%	NA	n/a	12.50%	0.00%
Halliburton Company	HAL	0.05%	1.89%	0.00%	7.00%	0.00%
Hasbro, Inc.	HAS	0.02%	2.81%	0.00%	8.50%	0.00%
HCA Healthcare, Inc.	HCA	0.20%	0.59%	0.00%	11.00%	0.02%
Healthpeak Properties, Inc.	DOC	0.02%	6.90%	0.00%	6.00%	0.00%
Henry Schein, Inc.	HSIC	0.02%	NA	n/a	10.50%	0.00%
Hewlett Packard Enterprise Company	HPE	0.05%	2.65%	0.00%	5.50%	0.00%
Hilton Worldwide Holdings Inc.	HLT	0.12%	0.19%	0.00%	15.00%	0.02%
Hologic, Inc.	HOLX	0.03%	NA	n/a	2.00%	0.00%
Honeywell International Inc.	HON	0.26%	1.95%	0.01%	9.50%	0.02%
Hormel Foods Corporation	HRL	0.02%	4.57%	0.00%	5.00%	0.00%
Host Hotels & Resorts, Inc.	HST	0.02%	4.08%	0.00%	10.50%	0.00%
Howmet Aerospace Inc.	HWM	0.18%	0.18%	0.00%	20.50%	0.04%
HP Inc.	HPQ	0.03%	6.32%	0.00%	5.00%	0.00%
Hubbell Incorporated	HUBB	0.05%	1.11%	0.00%	10.00%	0.00%
Humana Inc.	HUM	0.04%	1.86%	0.00%	2.00%	0.00%
Huntington Bancshares Incorporated	HBAN	0.06%	3.69%	0.00%	7.50%	0.00%
Huntington Ingalls Industries, Inc.	HII	0.03%	1.24%	0.00%	13.00%	0.00%

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED VL & BLOOMBERG GROWTH RATES

[1] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.17%
[2] Cap. Weighted Estimate of the S&P 500 Growth Rate	14.77%
[3] Cap. Weighted S&P 500 Estimated Required Market Return	16.02%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Weight In Index	[5] Estimated Dividend Yield	[6] Cap-Weighted Dividend Yield	[7] Value Line Long-Term Growth Estimate	[8] Cap. Weighted Long-Term Growth
IDEX Corporation	IEX	0.03%	1.36%	0.00%	4.00%	0.00%
IDEXX Laboratories, Inc.	IDXX	0.09%	NA	n/a	12.50%	0.01%
Illinois Tool Works Inc.	ITW	0.14%	2.22%	0.00%	9.00%	0.01%
Incyte Corporation	INCY	0.03%	NA	n/a	18.50%	0.01%
Ingersoll Rand Inc.	IR	0.06%	0.08%	0.00%	8.50%	0.01%
Insulet Corporation	PODD	0.03%	NA	n/a	30.50%	0.01%
Intel Corporation	INTC	0.38%	NA	n/a	25.00%	0.09%
Interactive Brokers Group, Inc.	IBKR	0.05%	0.45%	0.00%	16.00%	0.01%
Intercontinental Exchange, Inc.	ICE	0.16%	1.27%	0.00%	7.50%	0.01%
International Business Machines Corporation	IBM	0.38%	2.80%	0.01%	3.00%	0.01%
International Flavors & Fragrances Inc.	IFF	0.03%	1.95%	0.00%	2.50%	0.00%
International Paper Company	IP	0.04%	4.25%	0.00%	9.50%	0.00%
Intuit Inc.	INTU	0.19%	1.17%	0.00%	13.50%	0.03%
Intuitive Surgical, Inc.	ISRG	0.30%	NA	n/a	16.50%	0.05%
Invesco Ltd.	IVZ	0.02%	3.20%	0.00%	29.00%	0.01%
Invitation Homes Inc.	INVH	0.03%	4.56%	0.00%	6.50%	0.00%
IQVIA Holdings Inc.	IQV	0.05%	NA	n/a	7.00%	0.00%
Iron Mountain Incorporated	IRM	0.05%	3.19%	0.00%	8.50%	0.00%
J.B. Hunt Transport Services, Inc.	JBHT	0.04%	0.77%	0.00%	7.00%	0.00%
Jabil Inc.	JBL	0.05%	0.12%	0.00%	12.00%	0.01%
Jack Henry & Associates, Inc.	JKHY	0.02%	1.50%	0.00%	11.00%	0.00%
Jacobs Solutions Inc.	J	0.03%	1.04%	0.00%	7.00%	0.00%
Johnson & Johnson	JNJ	1.00%	2.09%	0.02%	5.00%	0.05%
Johnson Controls International plc	JCI	0.15%	1.07%	0.00%	18.00%	0.03%
JPMorgan Chase & Co.	JPM	1.35%	2.00%	0.03%	9.50%	0.13%
Kenvue Inc.	KVUE	0.00%	4.34%	0.00%	NA	n/a
Keurig Dr Pepper Inc.	KDP	0.07%	3.04%	0.00%	13.00%	0.01%
KeyCorp	KEY	0.04%	3.95%	0.00%	7.50%	0.00%
Keysight Technologies, Inc.	KEYS	0.09%	NA	n/a	8.00%	0.01%
Kimberly-Clark Corporation	KMB	0.06%	4.59%	0.00%	6.00%	0.00%
Kimco Realty Corporation	KIM	0.03%	4.42%	0.00%	27.50%	0.01%
Kinder Morgan, Inc.	KMI	0.12%	3.52%	0.00%	8.00%	0.01%
KKR & Co. Inc.	KKR	0.13%	0.84%	0.00%	7.00%	0.01%
KLA Corporation	KLAC	0.33%	0.50%	0.00%	12.50%	0.04%
L3Harris Technologies, Inc.	LHX	0.11%	1.37%	0.00%	14.00%	0.02%
Labcorp Holdings Inc.	LH	0.04%	1.00%	0.00%	5.50%	0.00%
Lam Research Corporation	LRCX	0.49%	0.44%	0.00%	14.50%	0.07%
Lamb Weston Holdings, Inc.	LW	0.01%	3.15%	0.00%	4.00%	0.00%
Las Vegas Sands Corp.	LVS	0.06%	2.12%	0.00%	30.00%	0.02%
Leidos Holdings, Inc.	LDOS	0.04%	0.98%	0.00%	11.00%	0.00%
Lennar Corporation	LEN	0.05%	1.75%	0.00%	-1.50%	0.00%
Lennox International Inc.	LII	0.03%	0.91%	0.00%	11.00%	0.00%
Linde plc	LIN	0.39%	1.20%	0.00%	7.00%	0.03%
Live Nation Entertainment, Inc.	LYV	0.00%	NA	n/a	NA	n/a
Lockheed Martin Corporation	LMT	0.25%	2.10%	0.01%	12.00%	0.03%
Loews Corporation	L	0.04%	0.23%	0.00%	15.50%	0.01%
Lowe's Companies, Inc.	LOW	0.25%	1.81%	0.00%	6.00%	0.01%
lululemon athletica inc.	LULU	0.04%	NA	n/a	4.00%	0.00%
LyondellBasell Industries N.V.	LYB	0.03%	8.34%	0.00%	-1.50%	0.00%
M&T Bank Corporation	MTB	0.05%	2.77%	0.00%	7.00%	0.00%
Marathon Petroleum Corporation	MPC	0.10%	2.02%	0.00%	-5.50%	-0.01%
Marriott International, Inc.	MAR	0.15%	0.78%	0.00%	9.00%	0.01%
Marsh & McLennan Companies, Inc.	MRSH	0.15%	1.93%	0.00%	14.00%	0.02%
Martin Marietta Materials, Inc.	MLM	0.07%	0.49%	0.00%	8.50%	0.01%
Masco Corporation	MAS	0.02%	1.79%	0.00%	7.50%	0.00%
Mastercard Incorporated	MA	0.77%	0.67%	0.01%	11.00%	0.08%
Match Group, Inc.	MTCH	0.01%	2.53%	0.00%	11.50%	0.00%
McCormick & Company, Incorporated	MKC	0.03%	2.70%	0.00%	6.00%	0.00%
McDonald's Corporation	MCD	0.40%	2.18%	0.01%	9.00%	0.04%
McKesson Corporation	MCK	0.20%	0.33%	0.00%	12.00%	0.02%
Medtronic plc	MDT	0.21%	2.90%	0.01%	6.50%	0.01%
Merck & Co., Inc.	MRK	0.51%	2.75%	0.01%	13.00%	0.07%
Meta Platforms, Inc.	META	2.73%	0.32%	0.01%	19.00%	0.52%
MetLife, Inc.	MET	0.08%	3.15%	0.00%	7.50%	0.01%
Mettler-Toledo International Inc.	MTD	0.05%	NA	n/a	7.50%	0.00%
MGM Resorts International	MGM	0.02%	NA	n/a	25.00%	0.00%
Microchip Technology Incorporated	MCHP	0.07%	2.44%	0.00%	3.00%	0.00%
Micron Technology, Inc.	MU	0.77%	0.11%	0.00%	65.50%	0.51%
Microsoft Corporation	MSFT	4.86%	0.93%	0.05%	13.50%	0.66%
Mid-America Apartment Communities, Inc.	MAA	0.03%	4.57%	0.00%	1.50%	0.00%
Moderna, Inc.	MRNA	0.00%	NA	n/a	NA	n/a
Molina Healthcare, Inc.	MOH	0.01%	NA	n/a	10.50%	0.00%
Molson Coors Beverage Company	TAP	0.02%	3.92%	0.00%	10.00%	0.00%
Mondelez International, Inc.	MDLZ	0.13%	3.25%	0.00%	7.50%	0.01%
Monolithic Power Systems, Inc.	MPWR	0.09%	0.70%	0.00%	12.00%	0.01%
Monster Beverage Corporation	MNST	0.14%	NA	n/a	13.00%	0.02%

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED VL & BLOOMBERG GROWTH RATES

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STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Weight In Index	[5] Estimated Dividend Yield	[6] Cap-Weighted Dividend Yield	[7] Value Line Long-Term Growth Estimate	[8] Cap. Weighted Long-Term Growth
Moody's Corporation	MCO	0.14%	0.86%	0.00%	10.00%	0.01%
Morgan Stanley	MS	0.44%	2.40%	0.01%	10.50%	0.05%
Motorola Solutions, Inc.	MSI	0.13%	1.00%	0.00%	9.50%	0.01%
MSCI Inc.	MSCI	0.07%	1.43%	0.00%	8.50%	0.01%
Nasdaq, Inc.	NDAQ	0.08%	1.23%	0.00%	9.50%	0.01%
NetApp, Inc.	NTAP	0.03%	2.10%	0.00%	9.50%	0.00%
Netflix, Inc.	NFLX	0.68%	NA	n/a	21.50%	0.15%
Newmont Corporation	NEM	0.24%	0.80%	0.00%	12.50%	0.03%
News Corporation	NWSA	0.02%	0.82%	0.00%	23.50%	0.01%
NextEra Energy, Inc.	NEE	0.33%	2.66%	0.01%	8.00%	0.03%
NIKE, Inc.	NKE	0.15%	2.64%	0.00%	2.50%	0.00%
NiSource Inc.	NI	0.04%	2.54%	0.00%	7.50%	0.00%
Nordson Corporation	NDSN	0.03%	1.12%	0.00%	11.50%	0.00%
Norfolk Southern Corporation	NSC	0.12%	1.72%	0.00%	8.50%	0.01%
Northern Trust Corporation	NTRS	0.04%	2.24%	0.00%	6.50%	0.00%
Northrop Grumman Corporation	NOC	0.17%	1.28%	0.00%	8.00%	0.01%
Norwegian Cruise Line Holdings Ltd.	NCLH	0.00%	NA	n/a	NA	n/a
NRG Energy, Inc.	NRG	0.06%	1.06%	0.00%	24.00%	0.02%
Nucor Corporation	NUE	0.07%	1.27%	0.00%	9.50%	0.01%
NVIDIA Corporation	NVDA	7.17%	0.02%	0.00%	37.00%	2.65%
NVR, Inc.	NVR	0.03%	NA	n/a	0.50%	0.00%
NXP Semiconductors N.V.	NXPI	0.10%	1.79%	0.00%	7.50%	0.01%
O'Reilly Automotive, Inc.	ORLY	0.13%	NA	n/a	10.50%	0.01%
Occidental Petroleum Corporation	OXY	0.00%	1.96%	0.00%	NA	n/a
Old Dominion Freight Line, Inc.	ODFL	0.07%	0.57%	0.00%	5.50%	0.00%
Omnicom Group Inc.	OMC	0.04%	3.75%	0.00%	7.00%	0.00%
ON Semiconductor Corporation	ON	0.04%	NA	n/a	4.00%	0.00%
ONEOK, Inc.	OKE	0.09%	5.17%	0.00%	12.50%	0.01%
Oracle Corporation	ORCL	0.70%	1.38%	0.01%	21.00%	0.15%
Otis Worldwide Corporation	OTIS	0.06%	1.82%	0.00%	9.50%	0.01%
PACCAR Inc	PCAR	0.11%	1.05%	0.00%	-1.00%	0.00%
Packaging Corporation of America	PKG	0.03%	2.15%	0.00%	5.50%	0.00%
Palantir Technologies Inc.	PLTR	0.00%	NA	n/a	NA	n/a
Palo Alto Networks, Inc.	PANW	0.20%	NA	n/a	26.50%	0.05%
Paramount Skydance Corporation	PSKY	0.00%	1.48%	0.00%	NA	n/a
Parker-Hannifin Corporation	PH	0.21%	0.71%	0.00%	14.00%	0.03%
Paychex, Inc.	PAYX	0.06%	4.61%	0.00%	8.00%	0.00%
Paycom Software, Inc.	PAYC	0.01%	1.19%	0.00%	11.00%	0.00%
PayPal Holdings, Inc.	PYPL	0.07%	1.21%	0.00%	13.50%	0.01%
Pentair plc	PNR	0.03%	1.05%	0.00%	13.00%	0.00%
PepsiCo, Inc.	PEP	0.39%	3.35%	0.01%	5.50%	0.02%
Pfizer Inc.	PFE	0.26%	6.22%	0.02%	6.00%	0.02%
PG&E Corporation	PCG	0.07%	1.05%	0.00%	9.50%	0.01%
Philip Morris International Inc.	PM	0.48%	3.15%	0.02%	5.00%	0.02%
Phillips 66	PSX	0.00%	3.29%	0.00%	NA	n/a
Pinnacle West Capital Corporation	PNW	0.02%	3.63%	0.00%	5.50%	0.00%
Pool Corporation	POOL	0.01%	2.20%	0.00%	0.50%	0.00%
PPG Industries, Inc.	PPG	0.05%	2.30%	0.00%	5.00%	0.00%
PPL Corporation	PPL	0.05%	2.92%	0.00%	7.50%	0.00%
Principal Financial Group, Inc.	PFG	0.03%	3.35%	0.00%	4.00%	0.00%
Prologis, Inc.	PLD	0.22%	3.00%	0.01%	2.50%	0.01%
Prudential Financial, Inc.	PRU	0.06%	5.69%	0.00%	7.00%	0.00%
PTC Inc.	PTC	0.03%	NA	n/a	10.00%	0.00%
Public Service Enterprise Group Incorporated	PEG	0.07%	3.11%	0.00%	7.50%	0.01%
Public Storage	PSA	0.09%	3.91%	0.00%	7.00%	0.01%
PulteGroup, Inc.	PHM	0.04%	0.76%	0.00%	3.00%	0.00%
Qnity Electronics, Inc.	Q	0.00%	0.25%	0.00%	NA	n/a
QUALCOMM Incorporated	QCOM	0.25%	2.50%	0.01%	6.50%	0.02%
Quanta Services, Inc.	PWR	0.14%	0.08%	0.00%	18.00%	0.03%
Quest Diagnostics Incorporated	DGX	0.04%	1.62%	0.00%	7.50%	0.00%
Ralph Lauren Corporation	RL	0.04%	1.01%	0.00%	16.00%	0.01%
Raymond James Financial, Inc.	RJF	0.05%	1.41%	0.00%	11.50%	0.01%
Realty Income Corporation	O	0.10%	4.84%	0.01%	5.00%	0.01%
Regency Centers Corporation	REG	0.02%	3.82%	0.00%	6.50%	0.00%
Regeneron Pharmaceuticals, Inc.	REGN	0.13%	0.48%	0.00%	7.00%	0.01%
Regions Financial Corporation	RF	0.04%	3.81%	0.00%	8.00%	0.00%
Republic Services, Inc.	RSG	0.12%	1.09%	0.00%	8.50%	0.01%
ResMed Inc.	RMD	0.06%	0.94%	0.00%	11.00%	0.01%
Revvity, Inc.	RVTY	0.02%	0.28%	0.00%	5.00%	0.00%
Robinhood Markets, Inc.	HOOD	0.00%	NA	n/a	NA	n/a
Rockwell Automation, Inc.	ROK	0.08%	1.35%	0.00%	9.50%	0.01%
Rollins, Inc.	ROL	0.05%	1.20%	0.00%	10.00%	0.00%
Roper Technologies, Inc.	ROP	0.06%	1.04%	0.00%	8.00%	0.00%
Ross Stores, Inc.	ROST	0.11%	0.79%	0.00%	7.50%	0.01%
Royal Caribbean Cruises Ltd.	RCL	0.00%	1.93%	0.00%	NA	n/a
RTX Corporation	RTX	0.45%	1.34%	0.01%	12.00%	0.05%

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED VL & BLOOMBERG GROWTH RATES

[1] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.17%
[2] Cap. Weighted Estimate of the S&P 500 Growth Rate	14.77%
[3] Cap. Weighted S&P 500 Estimated Required Market Return	16.02%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Weight In Index	[5] Estimated Dividend Yield	[6] Cap-Weighted Dividend Yield	[7] Value Line Long-Term Growth Estimate	[8] Cap. Weighted Long-Term Growth
S&P Global Inc.	SPGI	0.22%	0.88%	0.00%	8.50%	0.02%
Salesforce, Inc.	CRM	0.30%	0.90%	0.00%	21.00%	0.06%
Sandisk Corporation	SNDK	0.00%	NA	n/a	NA	n/a
SBA Communications Corporation	SBAC	0.04%	2.21%	0.00%	14.00%	0.00%
Seagate Technology Holdings plc	STX	0.15%	0.72%	0.00%	38.50%	0.06%
Sempra	SRE	0.10%	2.73%	0.00%	5.00%	0.01%
ServiceNow, Inc.	NOW	0.19%	NA	n/a	25.50%	0.05%
Simon Property Group, Inc.	SPG	0.11%	4.32%	0.00%	3.50%	0.00%
Skyworks Solutions, Inc.	SWKS	0.00%	4.77%	0.00%	NA	n/a
SLB N.V.	SLB	0.13%	2.30%	0.00%	9.50%	0.01%
Smurfit Westrock Plc	SW	0.00%	3.71%	0.00%	NA	n/a
Snap-on Incorporated	SNA	0.03%	2.53%	0.00%	4.50%	0.00%
Solventum Corporation	SOLV	0.00%	NA	n/a	NA	n/a
Southwest Airlines Co.	LUV	0.04%	1.46%	0.00%	17.50%	0.01%
Stanley Black & Decker, Inc.	SWK	0.02%	3.84%	0.00%	20.00%	0.00%
Starbucks Corporation	SBUX	0.19%	2.53%	0.00%	0.50%	0.00%
State Street Corporation	STT	0.06%	2.61%	0.00%	11.00%	0.01%
Steel Dynamics, Inc.	STLD	0.05%	1.10%	0.00%	0.50%	0.00%
STERIS plc	STE	0.04%	1.00%	0.00%	8.00%	0.00%
Stryker Corporation	SYK	0.25%	0.91%	0.00%	9.50%	0.02%
Super Micro Computer, Inc.	SMCI	0.03%	NA	n/a	22.00%	0.01%
Synchrony Financial	SYF	0.04%	1.74%	0.00%	8.50%	0.00%
Synopsys, Inc.	SNPS	0.13%	NA	n/a	12.00%	0.02%
Sysco Corporation	SYY	0.07%	2.37%	0.00%	7.00%	0.01%
T-Mobile US, Inc.	TMUS	0.40%	1.88%	0.01%	17.50%	0.07%
T. Rowe Price Group, Inc.	TROW	0.03%	5.50%	0.00%	9.50%	0.00%
Take-Two Interactive Software, Inc.	TTWO	0.00%	NA	n/a	NA	n/a
Tapestry, Inc.	TPR	0.05%	1.03%	0.00%	11.00%	0.01%
Targa Resources Corp.	TRGP	0.08%	1.70%	0.00%	19.00%	0.02%
Target Corporation	TGT	0.09%	4.01%	0.00%	7.00%	0.01%
TE Connectivity plc	TEL	0.11%	1.23%	0.00%	8.50%	0.01%
Teledyne Technologies Incorporated	TDY	0.05%	NA	n/a	10.00%	0.01%
Teradyne, Inc.	TER	0.08%	0.16%	0.00%	12.00%	0.01%
Tesla, Inc.	TSLA	2.52%	NA	n/a	10.50%	0.26%
Texas Instruments Incorporated	TXN	0.32%	2.68%	0.01%	4.50%	0.01%
Texas Pacific Land Corporation	TPL	0.06%	0.46%	0.00%	10.00%	0.01%
Textron Inc.	TXT	0.03%	0.08%	0.00%	13.50%	0.00%
The AES Corporation	AES	0.02%	4.07%	0.00%	29.50%	0.01%
The Allstate Corporation	ALL	0.09%	2.01%	0.00%	23.00%	0.02%
The Bank of New York Mellon Corporation	BK	0.14%	1.78%	0.00%	13.00%	0.02%
The Boeing Company	BA	0.00%	NA	n/a	NA	n/a
The Campbell's Company	CPB	0.01%	5.79%	0.00%	6.00%	0.00%
The Charles Schwab Corporation	SCHW	0.28%	1.34%	0.00%	13.50%	0.04%
The Cigna Group	CI	0.13%	2.15%	0.00%	8.50%	0.01%
The Clorox Company	CLX	0.03%	3.90%	0.00%	5.00%	0.00%
The Coca-Cola Company	KO	0.58%	2.60%	0.02%	7.00%	0.04%
The Cooper Companies, Inc.	COO	0.03%	NA	n/a	9.00%	0.00%
The Estée Lauder Companies Inc.	EL	0.07%	1.28%	0.00%	3.50%	0.00%
The Goldman Sachs Group, Inc.	GS	0.44%	2.09%	0.01%	12.00%	0.05%
The Hartford Insurance Group, Inc.	HIG	0.06%	1.70%	0.00%	7.00%	0.00%
The Hershey Company	HSY	0.08%	2.46%	0.00%	5.00%	0.00%
The Home Depot, Inc.	HD	0.63%	2.45%	0.02%	5.50%	0.03%
The J. M. Smucker Company	SJM	0.02%	3.79%	0.00%	4.50%	0.00%
The Kraft Heinz Company	KHC	0.05%	6.50%	0.00%	4.50%	0.00%
The Kroger Co.	KR	0.07%	2.05%	0.00%	6.00%	0.00%
The Mosaic Company	MOS	0.01%	3.16%	0.00%	-8.00%	0.00%
The PNC Financial Services Group, Inc.	PNC	0.14%	3.20%	0.00%	10.00%	0.01%
The Procter & Gamble Company	PG	0.65%	2.53%	0.02%	4.50%	0.03%
The Progressive Corporation	PGR	0.21%	0.19%	0.00%	14.00%	0.03%
The Sherwin-Williams Company	SHW	0.15%	0.88%	0.00%	10.00%	0.01%
The Southern Company	SO	0.18%	3.04%	0.01%	6.50%	0.01%
The TJX Companies, Inc.	TJX	0.30%	1.05%	0.00%	10.50%	0.03%
The Trade Desk, Inc.	TTD	0.02%	NA	n/a	26.00%	0.00%
The Travelers Companies, Inc.	TRV	0.11%	1.43%	0.00%	11.00%	0.01%
The Walt Disney Company	DIS	0.31%	1.41%	0.00%	18.50%	0.06%
The Williams Companies, Inc.	WMB	0.15%	2.81%	0.00%	9.00%	0.01%
Thermo Fisher Scientific Inc.	TMO	0.32%	0.36%	0.00%	6.00%	0.02%
TKO Group Holdings, Inc.	TKO	0.00%	1.39%	0.00%	NA	n/a
Tractor Supply Company	TSCO	0.05%	1.85%	0.00%	10.00%	0.00%
Trane Technologies plc	TT	0.17%	0.84%	0.00%	12.50%	0.02%
TransDigm Group Incorporated	TDG	0.12%	NA	n/a	13.50%	0.02%
Trimble Inc.	TRMB	0.03%	NA	n/a	6.50%	0.00%
Truist Financial Corporation	TFC	0.10%	4.22%	0.00%	5.50%	0.01%
Tyler Technologies, Inc.	TYL	0.03%	NA	n/a	10.50%	0.00%
Tyson Foods, Inc.	TSN	0.04%	3.14%	0.00%	5.50%	0.00%
U.S. Bancorp	USB	0.14%	3.81%	0.01%	7.50%	0.01%

MARKET RISK PREMIUM CALCULATION USING CAP. WEIGHTED VL & BLOOMBERG GROWTH RATES

[1] Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.17%
[2] Cap. Weighted Estimate of the S&P 500 Growth Rate	14.77%
[3] Cap. Weighted S&P 500 Estimated Required Market Return	16.02%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[4] Weight In Index	[5] Estimated Dividend Yield	[6] Cap-Weighted Dividend Yield	[7] Value Line Long-Term Growth Estimate	[8] Cap. Weighted Long-Term Growth
Uber Technologies, Inc.	UBER	0.00%	NA	n/a	NA	n/a
UDR, Inc.	UDR	0.02%	4.59%	0.00%	7.50%	0.00%
Ulta Beauty, Inc.	ULTA	0.05%	NA	n/a	6.50%	0.00%
Union Pacific Corporation	UNP	0.26%	2.08%	0.01%	9.00%	0.02%
United Airlines Holdings, Inc.	UAL	0.06%	NA	n/a	11.00%	0.01%
United Parcel Service, Inc.	UPS	0.16%	5.66%	0.01%	0.50%	0.00%
United Rentals, Inc.	URI	0.09%	0.94%	0.00%	9.50%	0.01%
UnitedHealth Group Incorporated	UNH	0.44%	3.01%	0.01%	1.00%	0.00%
Universal Health Services, Inc.	UHS	0.02%	0.39%	0.00%	13.00%	0.00%
Valero Energy Corporation	VLO	0.10%	2.35%	0.00%	-4.50%	0.00%
Ventas, Inc.	VTR	0.07%	2.41%	0.00%	23.00%	0.02%
Veralto Corporation	VLTO	0.04%	0.53%	0.00%	6.00%	0.00%
VeriSign, Inc.	VRSN	0.03%	1.42%	0.00%	10.00%	0.00%
Verisk Analytics, Inc.	VRSK	0.05%	0.96%	0.00%	6.50%	0.00%
Verizon Communications Inc.	VZ	0.35%	5.64%	0.02%	0.50%	0.00%
Vertex Pharmaceuticals Incorporated	VRTX	0.21%	NA	n/a	9.00%	0.02%
Viatris Inc.	VTRS	0.03%	3.22%	0.00%	0.00%	0.00%
VICI Properties Inc.	VICI	0.05%	5.96%	0.00%	8.00%	0.00%
Visa Inc.	V	1.02%	0.84%	0.01%	10.50%	0.11%
Vistra Corp.	VST	0.10%	0.52%	0.00%	34.50%	0.03%
Vulcan Materials Company	VMC	0.07%	0.67%	0.00%	8.50%	0.01%
W. R. Berkley Corporation	WRB	0.04%	0.50%	0.00%	11.50%	0.01%
W.W. Grainger, Inc.	GWW	0.09%	0.79%	0.00%	5.50%	0.00%
Walmart Inc.	WMT	1.70%	0.77%	0.01%	10.00%	0.17%
Warner Bros. Discovery, Inc.	WBD	0.00%	NA	n/a	NA	n/a
Waste Management, Inc.	WM	0.16%	1.37%	0.00%	8.00%	0.01%
Waters Corporation	WAT	0.05%	NA	n/a	6.50%	0.00%
WEC Energy Group, Inc.	WEC	0.06%	3.26%	0.00%	6.00%	0.00%
Wells Fargo & Company	WFC	0.42%	2.21%	0.01%	8.00%	0.03%
Welltower Inc.	WELL	0.24%	1.43%	0.00%	23.50%	0.06%
West Pharmaceutical Services, Inc.	WST	0.03%	0.35%	0.00%	5.00%	0.00%
Western Digital Corporation	WDC	0.00%	0.18%	0.00%	NA	n/a
Westinghouse Air Brake Technologies Corporation	WAB	0.07%	0.47%	0.00%	15.00%	0.01%
Weyerhaeuser Company	WY	0.03%	3.42%	0.00%	-1.50%	0.00%
Williams-Sonoma, Inc.	WSM	0.04%	1.28%	0.00%	5.00%	0.00%
Willis Towers Watson Public Limited Company	WTW	0.05%	1.22%	0.00%	10.00%	0.00%
Workday, Inc.	WDAY	0.00%	NA	n/a	NA	n/a
Wynn Resorts, Limited	WYNN	0.02%	0.92%	0.00%	27.00%	0.01%
Xcel Energy Inc.	XEL	0.09%	2.84%	0.00%	7.00%	0.01%
Xylem Inc.	XYL	0.05%	1.33%	0.00%	10.50%	0.01%
Yum! Brands, Inc.	YUM	0.08%	1.78%	0.00%	8.50%	0.01%
Zebra Technologies Corporation	ZBRA	0.02%	NA	n/a	7.00%	0.00%
Zimmer Biomet Holdings, Inc.	ZBH	0.03%	0.98%	0.00%	6.50%	0.00%
Zoetis Inc.	ZTS	0.09%	1.62%	0.00%	7.50%	0.01%

Notes:
[1] Equals sum of col. [6]
[2] Equals sum of col. [8]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Equals weight in S&P 500 based on market capitalization
[5] Source: S&P Capital IQ Pro
[6] Equals [4] x [5]
[7] Source: Value Line
[8] Equals [4] x [7]

KROLL HISTORICAL MARKET RISK PREMIUM ESTIMATE

[1] Historical Equity Risk Premium	7.37%

Notes:
[1] Source: Kroll Cost of Capital Navigator, United States Long-Horizon Equity Risk Premia, 1926-2025

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.79%	0.80	16.02%	11.23%	13.78%
Ameren Corporation	AEE	4.79%	0.80	16.02%	11.23%	13.78%
American Electric Power Company, Inc.	AEP	4.79%	0.70	16.02%	11.23%	12.65%
Duke Energy Corporation	DUK	4.79%	0.65	16.02%	11.23%	12.09%
Entergy Corporation	ETR	4.79%	0.75	16.02%	11.23%	13.22%
Evergy, Inc.	EVRG	4.79%	0.75	16.02%	11.23%	13.22%
FirstEnergy Corp	FE	4.79%	0.75	16.02%	11.23%	13.22%
IDACORP, Inc.	IDA	4.79%	0.70	16.02%	11.23%	12.65%
NextEra Energy, Inc.	NEE	4.79%	0.90	16.02%	11.23%	14.90%
OGE Energy Corp.	OGE	4.79%	0.85	16.02%	11.23%	14.34%
PPL Corporation	PPL	4.79%	0.80	16.02%	11.23%	13.78%
Southern Company	SO	4.79%	0.65	16.02%	11.23%	12.09%
Xcel Energy Inc.	XEL	4.79%	0.70	16.02%	11.23%	12.65%
Mean						13.26%

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED)
[2] Source: Value Line
[3] Source: Schedule 4.2 - SP 500 MRP
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VL BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q2 2026 - Q2 2027)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.76%	0.80	16.02%	11.26%	13.77%
Ameren Corporation	AEE	4.76%	0.80	16.02%	11.26%	13.77%
American Electric Power Company, Inc.	AEP	4.76%	0.70	16.02%	11.26%	12.64%
Duke Energy Corporation	DUK	4.76%	0.65	16.02%	11.26%	12.08%
Entergy Corporation	ETR	4.76%	0.75	16.02%	11.26%	13.21%
Evergy, Inc.	EVRG	4.76%	0.75	16.02%	11.26%	13.21%
FirstEnergy Corp	FE	4.76%	0.75	16.02%	11.26%	13.21%
IDACORP, Inc.	IDA	4.76%	0.70	16.02%	11.26%	12.64%
NextEra Energy, Inc.	NEE	4.76%	0.90	16.02%	11.26%	14.90%
OGE Energy Corp.	OGE	4.76%	0.85	16.02%	11.26%	14.33%
PPL Corporation	PPL	4.76%	0.80	16.02%	11.26%	13.77%
Southern Company	SO	4.76%	0.65	16.02%	11.26%	12.08%
Xcel Energy Inc.	XEL	4.76%	0.70	16.02%	11.26%	12.64%
Mean						13.25%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 45, No. 3, Feburary 27, 2026 at 2
[2] Source: Value Line
[3] Source: Schedule 4.2 - SP 500 MRP
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA

$K = Rf + \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)
Alliant Energy Corporation	LNT	4.60%	0.80	16.02%	11.42%	13.74%
Ameren Corporation	AEE	4.60%	0.80	16.02%	11.42%	13.74%
American Electric Power Company, Inc.	AEP	4.60%	0.70	16.02%	11.42%	12.60%
Duke Energy Corporation	DUK	4.60%	0.65	16.02%	11.42%	12.02%
Entergy Corporation	ETR	4.60%	0.75	16.02%	11.42%	13.17%
Evergy, Inc.	EVRG	4.60%	0.75	16.02%	11.42%	13.17%
FirstEnergy Corp	FE	4.60%	0.75	16.02%	11.42%	13.17%
IDACORP, Inc.	IDA	4.60%	0.70	16.02%	11.42%	12.60%
NextEra Energy, Inc.	NEE	4.60%	0.90	16.02%	11.42%	14.88%
OGE Energy Corp.	OGE	4.60%	0.85	16.02%	11.42%	14.31%
PPL Corporation	PPL	4.60%	0.80	16.02%	11.42%	13.74%
Southern Company	SO	4.60%	0.65	16.02%	11.42%	12.02%
Xcel Energy Inc.	XEL	4.60%	0.70	16.02%	11.42%	12.60%
Mean						13.21%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025 at 14
[2] Source: Value Line
[3] Source: Schedule 4.2 - SP 500 MRP
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG 5-YEAR BETA

$K = Rf + \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)
Alliant Energy Corporation	LNT	4.79%	0.60	16.02%	11.23%	11.48%
Ameren Corporation	AEE	4.79%	0.62	16.02%	11.23%	11.70%
American Electric Power Company, Inc.	AEP	4.79%	0.53	16.02%	11.23%	10.73%
Duke Energy Corporation	DUK	4.79%	0.50	16.02%	11.23%	10.45%
Entergy Corporation	ETR	4.79%	0.65	16.02%	11.23%	12.06%
Evergy, Inc.	EVRG	4.79%	0.59	16.02%	11.23%	11.47%
FirstEnergy Corp	FE	4.79%	0.56	16.02%	11.23%	11.07%
IDACORP, Inc.	IDA	4.79%	0.55	16.02%	11.23%	10.94%
NextEra Energy, Inc.	NEE	4.79%	0.74	16.02%	11.23%	13.16%
OGE Energy Corp.	OGE	4.79%	0.64	16.02%	11.23%	12.02%
PPL Corporation	PPL	4.79%	0.63	16.02%	11.23%	11.87%
Southern Company	SO	4.79%	0.53	16.02%	11.23%	10.77%
Xcel Energy Inc.	XEL	4.79%	0.57	16.02%	11.23%	11.18%
Mean						11.45%

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED)
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] Source: Schedule 4.2 - SP 500 MRP
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG 5-YEAR BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q2 2026 - Q2 2027)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.76%	0.60	16.02%	11.26%	11.46%
Ameren Corporation	AEE	4.76%	0.62	16.02%	11.26%	11.69%
American Electric Power Company, Inc.	AEP	4.76%	0.53	16.02%	11.26%	10.72%
Duke Energy Corporation	DUK	4.76%	0.50	16.02%	11.26%	10.43%
Entergy Corporation	ETR	4.76%	0.65	16.02%	11.26%	12.05%
Evergy, Inc.	EVRG	4.76%	0.59	16.02%	11.26%	11.45%
FirstEnergy Corp	FE	4.76%	0.56	16.02%	11.26%	11.05%
IDACORP, Inc.	IDA	4.76%	0.55	16.02%	11.26%	10.93%
NextEra Energy, Inc.	NEE	4.76%	0.74	16.02%	11.26%	13.15%
OGE Energy Corp.	OGE	4.76%	0.64	16.02%	11.26%	12.01%
PPL Corporation	PPL	4.76%	0.63	16.02%	11.26%	11.86%
Southern Company	SO	4.76%	0.53	16.02%	11.26%	10.75%
Xcel Energy Inc.	XEL	4.76%	0.57	16.02%	11.26%	11.16%
Mean						11.44%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 45, No. 3, Feburary 27, 2026 at 2
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] Source: Schedule 4.2 - SP 500 MRP
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG 5-YEAR BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2027 - 2031)	[2] Beta (β)	[3] Market Return (Rm)	[4] Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.60%	0.60	16.02%	11.42%	11.40%
Ameren Corporation	AEE	4.60%	0.62	16.02%	11.42%	11.63%
American Electric Power Company, Inc.	AEP	4.60%	0.53	16.02%	11.42%	10.64%
Duke Energy Corporation	DUK	4.60%	0.50	16.02%	11.42%	10.35%
Entergy Corporation	ETR	4.60%	0.65	16.02%	11.42%	11.99%
Evergy, Inc.	EVRG	4.60%	0.59	16.02%	11.42%	11.39%
FirstEnergy Corp	FE	4.60%	0.56	16.02%	11.42%	10.98%
IDACORP, Inc.	IDA	4.60%	0.55	16.02%	11.42%	10.85%
NextEra Energy, Inc.	NEE	4.60%	0.74	16.02%	11.42%	13.11%
OGE Energy Corp.	OGE	4.60%	0.64	16.02%	11.42%	11.95%
PPL Corporation	PPL	4.60%	0.63	16.02%	11.42%	11.80%
Southern Company	SO	4.60%	0.53	16.02%	11.42%	10.68%
Xcel Energy Inc.	XEL	4.60%	0.57	16.02%	11.42%	11.09%
Mean						11.37%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025 at 14
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] Source: Schedule 4.2 - SP 500 MRP
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG 10-YEAR BETA

$K = Rf + \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Current 30-day average of 30-year U.S. Treasury bond yield	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)
Alliant Energy Corporation	LNT	4.79%	0.75	16.02%	11.23%	13.21%
Ameren Corporation	AEE	4.79%	0.72	16.02%	11.23%	12.89%
American Electric Power Company, Inc.	AEP	4.79%	0.71	16.02%	11.23%	12.76%
Duke Energy Corporation	DUK	4.79%	0.68	16.02%	11.23%	12.45%
Entergy Corporation	ETR	4.79%	0.83	16.02%	11.23%	14.10%
Evergy, Inc.	EVRG	4.79%	0.75	16.02%	11.23%	13.17%
FirstEnergy Corp	FE	4.79%	0.74	16.02%	11.23%	13.15%
IDACORP, Inc.	IDA	4.79%	0.74	16.02%	11.23%	13.07%
NextEra Energy, Inc.	NEE	4.79%	0.79	16.02%	11.23%	13.72%
OGE Energy Corp.	OGE	4.79%	0.87	16.02%	11.23%	14.55%
PPL Corporation	PPL	4.79%	0.90	16.02%	11.23%	14.85%
Southern Company	SO	4.79%	0.74	16.02%	11.23%	13.11%
Xcel Energy Inc.	XEL	4.79%	0.72	16.02%	11.23%	12.83%
Mean						13.37%

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED)
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] Source: Schedule 4.2 - SP 500 MRP
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG 10-YEAR BETA

$K = Rf + \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Near-term projected 30-year U.S. Treasury bond yield (Q2 2026 - Q2 2027)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)
Alliant Energy Corporation	LNT	4.76%	0.75	16.02%	11.26%	13.20%
Ameren Corporation	AEE	4.76%	0.72	16.02%	11.26%	12.88%
American Electric Power Company, Inc.	AEP	4.76%	0.71	16.02%	11.26%	12.75%
Duke Energy Corporation	DUK	4.76%	0.68	16.02%	11.26%	12.44%
Entergy Corporation	ETR	4.76%	0.83	16.02%	11.26%	14.09%
Evergy, Inc.	EVRG	4.76%	0.75	16.02%	11.26%	13.16%
FirstEnergy Corp	FE	4.76%	0.74	16.02%	11.26%	13.14%
IDACORP, Inc.	IDA	4.76%	0.74	16.02%	11.26%	13.07%
NextEra Energy, Inc.	NEE	4.76%	0.79	16.02%	11.26%	13.71%
OGE Energy Corp.	OGE	4.76%	0.87	16.02%	11.26%	14.54%
PPL Corporation	PPL	4.76%	0.90	16.02%	11.26%	14.85%
Southern Company	SO	4.76%	0.74	16.02%	11.26%	13.10%
Xcel Energy Inc.	XEL	4.76%	0.72	16.02%	11.26%	12.82%
Mean						13.37%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 45, No. 3, Feburary 27, 2026 at 2
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] Source: Schedule 4.2 - SP 500 MRP
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG 10-YEAR BETA

$K = Rf + \beta \times (Rm - Rf)$

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Projected 30-year U.S. Treasury bond yield (2027 - 2031)	Beta (β)	Market Return (Rm)	Market Risk Premium (Rm − Rf)	CAPM ROE (K)
Alliant Energy Corporation	LNT	4.60%	0.75	16.02%	11.42%	13.16%
Ameren Corporation	AEE	4.60%	0.72	16.02%	11.42%	12.83%
American Electric Power Company, Inc.	AEP	4.60%	0.71	16.02%	11.42%	12.70%
Duke Energy Corporation	DUK	4.60%	0.68	16.02%	11.42%	12.39%
Entergy Corporation	ETR	4.60%	0.83	16.02%	11.42%	14.06%
Evergy, Inc.	EVRG	4.60%	0.75	16.02%	11.42%	13.12%
FirstEnergy Corp	FE	4.60%	0.74	16.02%	11.42%	13.10%
IDACORP, Inc.	IDA	4.60%	0.74	16.02%	11.42%	13.02%
NextEra Energy, Inc.	NEE	4.60%	0.79	16.02%	11.42%	13.68%
OGE Energy Corp.	OGE	4.60%	0.87	16.02%	11.42%	14.52%
PPL Corporation	PPL	4.60%	0.90	16.02%	11.42%	14.83%
Southern Company	SO	4.60%	0.74	16.02%	11.42%	13.06%
Xcel Energy Inc.	XEL	4.60%	0.72	16.02%	11.42%	12.77%
Mean						13.33%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025 at 14
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] Source: Schedule 4.2 - SP 500 MRP
[4] Equals [3] - [1]
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & VL BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Historical Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.79%	0.80	n/a	7.37%	10.69%
Ameren Corporation	AEE	4.79%	0.80	n/a	7.37%	10.69%
American Electric Power Company, Inc.	AEP	4.79%	0.70	n/a	7.37%	9.95%
Duke Energy Corporation	DUK	4.79%	0.65	n/a	7.37%	9.58%
Entergy Corporation	ETR	4.79%	0.75	n/a	7.37%	10.32%
Evergy, Inc.	EVRG	4.79%	0.75	n/a	7.37%	10.32%
FirstEnergy Corp	FE	4.79%	0.75	n/a	7.37%	10.32%
IDACORP, Inc.	IDA	4.79%	0.70	n/a	7.37%	9.95%
NextEra Energy, Inc.	NEE	4.79%	0.90	n/a	7.37%	11.42%
OGE Energy Corp.	OGE	4.79%	0.85	n/a	7.37%	11.05%
PPL Corporation	PPL	4.79%	0.80	n/a	7.37%	10.69%
Southern Company	SO	4.79%	0.65	n/a	7.37%	9.58%
Xcel Energy Inc.	XEL	4.79%	0.70	n/a	7.37%	9.95%
Mean						10.35%

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED)
[2] Source: Value Line
[3] n/a
[4] Source: Schedule 4.3 - Historical MRP
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & VL BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q2 2026 - Q2 2027)	[2] Beta (β)	[3] Market Return (Rm)	[4] Historical Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.76%	0.80	n/a	7.37%	10.66%
Ameren Corporation	AEE	4.76%	0.80	n/a	7.37%	10.66%
American Electric Power Company, Inc.	AEP	4.76%	0.70	n/a	7.37%	9.92%
Duke Energy Corporation	DUK	4.76%	0.65	n/a	7.37%	9.55%
Entergy Corporation	ETR	4.76%	0.75	n/a	7.37%	10.29%
Evergy, Inc.	EVRG	4.76%	0.75	n/a	7.37%	10.29%
FirstEnergy Corp	FE	4.76%	0.75	n/a	7.37%	10.29%
IDACORP, Inc.	IDA	4.76%	0.70	n/a	7.37%	9.92%
NextEra Energy, Inc.	NEE	4.76%	0.90	n/a	7.37%	11.39%
OGE Energy Corp.	OGE	4.76%	0.85	n/a	7.37%	11.02%
PPL Corporation	PPL	4.76%	0.80	n/a	7.37%	10.66%
Southern Company	SO	4.76%	0.65	n/a	7.37%	9.55%
Xcel Energy Inc.	XEL	4.76%	0.70	n/a	7.37%	9.92%
Mean						10.32%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 45, No. 3, Feburary 27, 2026 at 2
[2] Source: Value Line
[3] n/a
[4] Source: Schedule 4.3 - Historical MRP
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & VL BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2027 - 2031)	[2] Beta (β)	[3] Market Return (Rm)	[4] Historical Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.60%	0.80	n/a	7.37%	10.50%
Ameren Corporation	AEE	4.60%	0.80	n/a	7.37%	10.50%
American Electric Power Company, Inc.	AEP	4.60%	0.70	n/a	7.37%	9.76%
Duke Energy Corporation	DUK	4.60%	0.65	n/a	7.37%	9.39%
Entergy Corporation	ETR	4.60%	0.75	n/a	7.37%	10.13%
Evergy, Inc.	EVRG	4.60%	0.75	n/a	7.37%	10.13%
FirstEnergy Corp	FE	4.60%	0.75	n/a	7.37%	10.13%
IDACORP, Inc.	IDA	4.60%	0.70	n/a	7.37%	9.76%
NextEra Energy, Inc.	NEE	4.60%	0.90	n/a	7.37%	11.23%
OGE Energy Corp.	OGE	4.60%	0.85	n/a	7.37%	10.86%
PPL Corporation	PPL	4.60%	0.80	n/a	7.37%	10.50%
Southern Company	SO	4.60%	0.65	n/a	7.37%	9.39%
Xcel Energy Inc.	XEL	4.60%	0.70	n/a	7.37%	9.76%
Mean						10.16%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025 at 14
[2] Source: Value Line
[3] n/a
[4] Source: Schedule 4.3 - Historical MRP
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG 5-YEAR BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Historical Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.79%	0.60	n/a	7.37%	9.18%
Ameren Corporation	AEE	4.79%	0.62	n/a	7.37%	9.32%
American Electric Power Company, Inc.	AEP	4.79%	0.53	n/a	7.37%	8.69%
Duke Energy Corporation	DUK	4.79%	0.50	n/a	7.37%	8.50%
Entergy Corporation	ETR	4.79%	0.65	n/a	7.37%	9.56%
Evergy, Inc.	EVRG	4.79%	0.59	n/a	7.37%	9.17%
FirstEnergy Corp	FE	4.79%	0.56	n/a	7.37%	8.91%
IDACORP, Inc.	IDA	4.79%	0.55	n/a	7.37%	8.83%
NextEra Energy, Inc.	NEE	4.79%	0.74	n/a	7.37%	10.28%
OGE Energy Corp.	OGE	4.79%	0.64	n/a	7.37%	9.53%
PPL Corporation	PPL	4.79%	0.63	n/a	7.37%	9.44%
Southern Company	SO	4.79%	0.53	n/a	7.37%	8.71%
Xcel Energy Inc.	XEL	4.79%	0.57	n/a	7.37%	8.98%
Mean						9.16%

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED)
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] n/a
[4] Source: Schedule 4.3 - Historical MRP
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG 5-YEAR BETA

$$K = Rf + \beta \times (Rm - Rf)$$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q2 2026 - Q2 2027)	[2] Beta (β)	[3] Market Return (Rm)	[4] Historical Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.76%	0.60	n/a	7.37%	9.15%
Ameren Corporation	AEE	4.76%	0.62	n/a	7.37%	9.29%
American Electric Power Company, Inc.	AEP	4.76%	0.53	n/a	7.37%	8.66%
Duke Energy Corporation	DUK	4.76%	0.50	n/a	7.37%	8.47%
Entergy Corporation	ETR	4.76%	0.65	n/a	7.37%	9.53%
Evergy, Inc.	EVRG	4.76%	0.59	n/a	7.37%	9.14%
FirstEnergy Corp	FE	4.76%	0.56	n/a	7.37%	8.88%
IDACORP, Inc.	IDA	4.76%	0.55	n/a	7.37%	8.80%
NextEra Energy, Inc.	NEE	4.76%	0.74	n/a	7.37%	10.25%
OGE Energy Corp.	OGE	4.76%	0.64	n/a	7.37%	9.50%
PPL Corporation	PPL	4.76%	0.63	n/a	7.37%	9.41%
Southern Company	SO	4.76%	0.53	n/a	7.37%	8.68%
Xcel Energy Inc.	XEL	4.76%	0.57	n/a	7.37%	8.95%
Mean						9.13%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 45, No. 3, Feburary 27, 2026 at 2
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] n/a
[4] Source: Schedule 4.3 - Historical MRP
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG 5-YEAR BETA

$$K = Rf + \beta \times (Rm - Rf)$$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2027 - 2031)	[2] Beta (β)	[3] Market Return (Rm)	[4] Historical Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.60%	0.60	n/a	7.37%	8.99%
Ameren Corporation	AEE	4.60%	0.62	n/a	7.37%	9.13%
American Electric Power Company, Inc.	AEP	4.60%	0.53	n/a	7.37%	8.50%
Duke Energy Corporation	DUK	4.60%	0.50	n/a	7.37%	8.31%
Entergy Corporation	ETR	4.60%	0.65	n/a	7.37%	9.37%
Evergy, Inc.	EVRG	4.60%	0.59	n/a	7.37%	8.98%
FirstEnergy Corp	FE	4.60%	0.56	n/a	7.37%	8.72%
IDACORP, Inc.	IDA	4.60%	0.55	n/a	7.37%	8.64%
NextEra Energy, Inc.	NEE	4.60%	0.74	n/a	7.37%	10.09%
OGE Energy Corp.	OGE	4.60%	0.64	n/a	7.37%	9.34%
PPL Corporation	PPL	4.60%	0.63	n/a	7.37%	9.25%
Southern Company	SO	4.60%	0.53	n/a	7.37%	8.52%
Xcel Energy Inc.	XEL	4.60%	0.57	n/a	7.37%	8.79%
Mean						8.97%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025 at 14
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] n/a
[4] Source: Schedule 4.3 - Historical MRP
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- CURRENT RISK-FREE RATE & BLOOMBERG 10-YEAR BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Current 30-day average of 30-year U.S. Treasury bond yield	[2] Beta (β)	[3] Market Return (Rm)	[4] Historical Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.79%	0.75	n/a	7.37%	10.31%
Ameren Corporation	AEE	4.79%	0.72	n/a	7.37%	10.10%
American Electric Power Company, Inc.	AEP	4.79%	0.71	n/a	7.37%	10.02%
Duke Energy Corporation	DUK	4.79%	0.68	n/a	7.37%	9.82%
Entergy Corporation	ETR	4.79%	0.83	n/a	7.37%	10.90%
Evergy, Inc.	EVRG	4.79%	0.75	n/a	7.37%	10.29%
FirstEnergy Corp	FE	4.79%	0.74	n/a	7.37%	10.28%
IDACORP, Inc.	IDA	4.79%	0.74	n/a	7.37%	10.22%
NextEra Energy, Inc.	NEE	4.79%	0.79	n/a	7.37%	10.65%
OGE Energy Corp.	OGE	4.79%	0.87	n/a	7.37%	11.19%
PPL Corporation	PPL	4.79%	0.90	n/a	7.37%	11.39%
Southern Company	SO	4.79%	0.74	n/a	7.37%	10.25%
Xcel Energy Inc.	XEL	4.79%	0.72	n/a	7.37%	10.06%
Mean						10.42%

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED)
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] n/a
[4] Source: Schedule 4.3 - Historical MRP
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- NEAR-TERM PROJECTED RISK-FREE RATE & BLOOMBERG 10-YEAR BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Near-term projected 30-year U.S. Treasury bond yield (Q2 2026 - Q2 2027)	[2] Beta (β)	[3] Market Return (Rm)	[4] Historical Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.76%	0.75	n/a	7.37%	10.28%
Ameren Corporation	AEE	4.76%	0.72	n/a	7.37%	10.07%
American Electric Power Company, Inc.	AEP	4.76%	0.71	n/a	7.37%	9.99%
Duke Energy Corporation	DUK	4.76%	0.68	n/a	7.37%	9.79%
Entergy Corporation	ETR	4.76%	0.83	n/a	7.37%	10.87%
Evergy, Inc.	EVRG	4.76%	0.75	n/a	7.37%	10.26%
FirstEnergy Corp	FE	4.76%	0.74	n/a	7.37%	10.25%
IDACORP, Inc.	IDA	4.76%	0.74	n/a	7.37%	10.19%
NextEra Energy, Inc.	NEE	4.76%	0.79	n/a	7.37%	10.62%
OGE Energy Corp.	OGE	4.76%	0.87	n/a	7.37%	11.16%
PPL Corporation	PPL	4.76%	0.90	n/a	7.37%	11.36%
Southern Company	SO	4.76%	0.74	n/a	7.37%	10.22%
Xcel Energy Inc.	XEL	4.76%	0.72	n/a	7.37%	10.03%
Mean						10.39%

Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 45, No. 3, Feburary 27, 2026 at 2
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] n/a
[4] Source: Schedule 4.3 - Historical MRP
[5] Equals [1] + [2] x [4]

CAPITAL ASSET PRICING MODEL -- LONG-TERM PROJECTED RISK-FREE RATE & BLOOMBERG 10-YEAR BETA

$K = Rf + \beta \times (Rm - Rf)$

Company	Ticker	[1] Projected 30-year U.S. Treasury bond yield (2027 - 2031)	[2] Beta (β)	[3] Market Return (Rm)	[4] Historical Market Risk Premium (Rm − Rf)	[5] CAPM ROE (K)
Alliant Energy Corporation	LNT	4.60%	0.75	n/a	7.37%	10.12%
Ameren Corporation	AEE	4.60%	0.72	n/a	7.37%	9.91%
American Electric Power Company, Inc.	AEP	4.60%	0.71	n/a	7.37%	9.83%
Duke Energy Corporation	DUK	4.60%	0.68	n/a	7.37%	9.63%
Entergy Corporation	ETR	4.60%	0.83	n/a	7.37%	10.71%
Evergy, Inc.	EVRG	4.60%	0.75	n/a	7.37%	10.10%
FirstEnergy Corp	FE	4.60%	0.74	n/a	7.37%	10.09%
IDACORP, Inc.	IDA	4.60%	0.74	n/a	7.37%	10.03%
NextEra Energy, Inc.	NEE	4.60%	0.79	n/a	7.37%	10.46%
OGE Energy Corp.	OGE	4.60%	0.87	n/a	7.37%	11.00%
PPL Corporation	PPL	4.60%	0.90	n/a	7.37%	11.20%
Southern Company	SO	4.60%	0.74	n/a	7.37%	10.06%
Xcel Energy Inc.	XEL	4.60%	0.72	n/a	7.37%	9.87%
Mean						10.23%

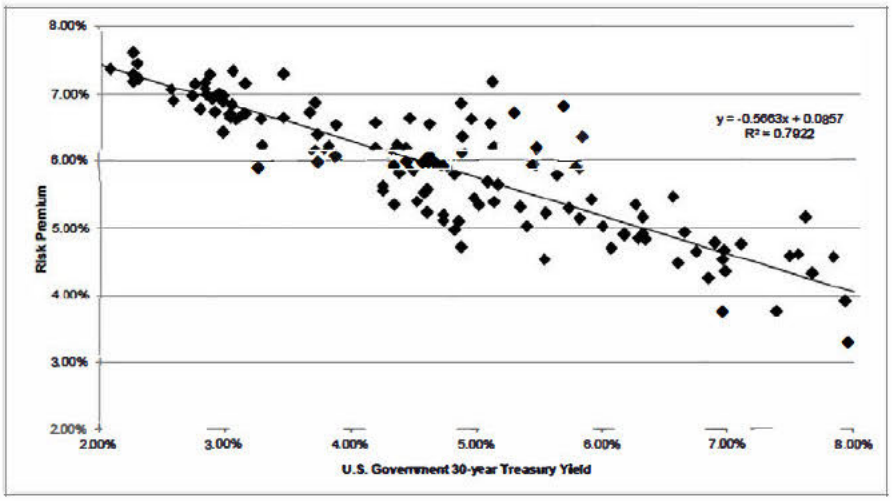
Notes:
[1] Source: Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025 at 14
[2] Source: Bloomberg Professional, as of February 27, 2026
[3] n/a
[4] Source: Schedule 4.3 - Historical MRP
[5] Equals [1] + [2] x [4]

TREASURY BOND YIELD PLUS RISK PREMIUM
VERTICALLY INTEGRATED ELECTRIC UTILITIES

	[1]	[2]	[3]
	Average Authorized Integrated Electric ROE	U.S. Govt. 30-year Treasury	Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	11.00%	5.70%	5.30%
2001.3	10.76%	5.52%	5.23%
2001.4	11.99%	5.30%	6.70%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.65%	5.08%	6.57%
2002.4	11.57%	4.93%	6.64%
2003.1	11.72%	4.85%	6.87%
2003.2	11.16%	4.60%	6.56%
2003.3	10.50%	5.11%	5.39%
2003.4	11.34%	5.11%	6.23%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	11.24%	4.86%	6.38%
2005.1	10.63%	4.69%	5.93%
2005.2	10.31%	4.47%	5.85%
2005.3	11.08%	4.44%	6.65%
2005.4	10.63%	4.68%	5.95%
2006.1	10.70%	4.63%	6.06%
2006.2	10.79%	5.14%	5.65%
2006.3	10.35%	4.99%	5.35%
2006.4	10.65%	4.74%	5.91%

TREASURY BOND YIELD PLUS RISK PREMIUM
VERTICALLY INTEGRATED ELECTRIC UTILITIES

	[1] Average Authorized Integrated Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
2007.1	10.59%	4.80%	5.80%
2007.2	10.33%	4.99%	5.34%
2007.3	10.40%	4.95%	5.45%
2007.4	10.65%	4.61%	6.04%
2008.1	10.62%	4.41%	6.21%
2008.2	10.54%	4.57%	5.97%
2008.3	10.43%	4.44%	5.98%
2008.4	10.39%	3.65%	6.74%
2009.1	10.75%	3.44%	7.31%
2009.2	10.75%	4.17%	6.58%
2009.3	10.50%	4.32%	6.18%
2009.4	10.59%	4.34%	6.26%
2010.1	10.59%	4.62%	5.97%
2010.2	10.18%	4.36%	5.82%
2010.3	10.40%	3.86%	6.55%
2010.4	10.38%	4.17%	6.21%
2011.1	10.09%	4.56%	5.53%
2011.2	10.26%	4.34%	5.92%
2011.3	10.57%	3.69%	6.88%
2011.4	10.39%	3.04%	7.35%
2012.1	10.30%	3.14%	7.17%
2012.2	9.95%	2.93%	7.02%
2012.3	9.90%	2.74%	7.16%
2012.4	10.16%	2.86%	7.30%
2013.1	9.85%	3.13%	6.72%
2013.2	9.86%	3.14%	6.72%
2013.3	10.12%	3.71%	6.41%
2013.4	9.97%	3.79%	6.18%
2014.1	9.86%	3.69%	6.17%
2014.2	10.10%	3.44%	6.66%
2014.3	9.90%	3.26%	6.64%
2014.4	9.94%	2.96%	6.98%
2015.1	9.64%	2.55%	7.08%
2015.2	9.83%	2.88%	6.94%
2015.3	9.40%	2.96%	6.44%
2015.4	9.86%	2.96%	6.90%
2016.1	9.70%	2.72%	6.98%
2016.2	9.48%	2.57%	6.91%
2016.3	9.74%	2.28%	7.46%
2016.4	9.83%	2.83%	7.00%
2017.1	9.72%	3.04%	6.67%
2017.2	9.64%	2.90%	6.75%
2017.3	10.00%	2.82%	7.18%
2017.4	9.91%	2.82%	7.09%
2018.1	9.69%	3.02%	6.66%
2018.2	9.75%	3.09%	6.66%
2018.3	9.69%	3.06%	6.63%
2018.4	9.52%	3.27%	6.25%
2019.1	9.72%	3.01%	6.71%
2019.2	9.58%	2.78%	6.79%
2019.3	9.53%	2.29%	7.24%
2019.4	9.89%	2.25%	7.63%
2020.1	9.72%	1.89%	7.83%
2020.2	9.58%	1.38%	8.20%
2020.3	9.30%	1.37%	7.93%
2020.4	9.54%	1.62%	7.92%
2021.1	9.45%	2.07%	7.38%
2021.2	9.55%	2.25%	7.30%
2021.3	9.27%	1.93%	7.34%
2021.4	9.69%	1.94%	7.75%
2022.1	9.45%	2.25%	7.20%
2022.2	9.88%	3.03%	6.85%
2022.3	9.14%	3.26%	5.88%
2022.4	9.94%	3.88%	6.06%
2023.1	9.72%	3.74%	5.97%
2023.2	10.04%	3.80%	6.24%
2023.3	9.79%	4.23%	5.56%
2023.4	9.82%	4.58%	5.24%
2024.1	9.67%	4.32%	5.35%
2024.2	10.16%	4.58%	5.58%
2024.3	9.86%	4.23%	5.63%
2024.4	9.90%	4.50%	5.40%
2025.1	9.83%	4.71%	5.12%
2025.2	9.95%	4.83%	5.11%
2025.3	9.58%	4.85%	4.73%
2025.4	9.91%	4.71%	5.20%
2026.1	9.78%	4.80%	4.98%
AVERAGE	10.54%	4.54%	5.99%
MEDIAN	10.40%	4.58%	6.04%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.890052171
R Square	0.792192868
Adjusted R Square	0.790653556
Standard Error	0.004600605
Observations	137

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.010892666	0.010892666	514.6408403	6.73E-48
Residual	135	0.002857352	2.11656E-05		
Total	136	0.013750018			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.085675209	0.001200268	71.38008721	4.36E-109	0.083301449	0.088048969	0.083301449	0.088048969
X Variable 1	-0.566339273	0.024964597	-22.68569682	6.73E-48	-0.615711563	-0.516966982	-0.615711563	-0.516966982

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-day average of 30-year U.S. Treasury bond yield [4]	4.79%	5.85%	10.64%
Blue Chip Near-Term Projected Forecast (Q2 2026 - Q2 2027) [5]	4.76%	5.87%	10.63%
Blue Chip Long-Term Projected Forecast (2027-2031) [6]	4.60%	5.96%	10.56%
AVERAGE			10.61%

Notes:
[1] Source: Regulatory Research Associates, rate cases through February 28, 2026
[2] Source: Bloomberg Professional, quarterly bond yields are the average of each trading day in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional, 30-day average as of February 28, 2026
[5] Source: Blue Chip Financial Forecasts, Vol. 45, No. 3, February 27, 2026 at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025 at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.085675 + (-0.566339 x Column [7])
[9] Equals Column [7] + Column [8]

EXPECTED EARNINGS ANALYSIS

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Value Line ROE 2028-2030	Value Line Total Capital 2024	Value Line Common Equity Ratio 2024	Total Equity 2024	Value Line Total Capital 2028-2030	Value Line Common Equity Ratio 2028-2030	Total Equity 2028-2030	Compund Annual Growth Rate	Adjustment Factor	Adjusted Return on Common Equity
Alliant Energy Corporation	LNT	12.00%	15,681	44.70%	7,009	17,070	48.00%	8,194	3.17%	1.016	12.19%
Ameren Corporation	AEE	10.00%	25,432	45.30%	11,521	29,500	48.50%	14,308	4.43%	1.022	10.22%
American Electric Power Company, Inc.	AEP	11.00%	67,528	42.40%	28,632	75,900	42.50%	32,258	2.41%	1.012	11.13%
Duke Energy Corporation	DUK	10.50%	131,300	39.00%	51,207	161,400	39.00%	62,946	4.21%	1.021	10.72%
Entergy Corporation	ETR	9.50%	41,917	36.00%	15,090	56,215	36.50%	20,518	6.34%	1.031	9.79%
Evergy, Inc.	EVRG	10.00%	21,250	48.50%	10,306	23,400	46.50%	10,881	1.09%	1.005	10.05%
FirstEnergy Corp	FE	12.50%	38,300	33.50%	12,831	51,400	34.00%	17,476	6.38%	1.031	12.89%
IDACORP, Inc.	IDA	10.00%	6,385	52.20%	3,333	7,375	56.00%	4,130	4.38%	1.021	10.21%
NextEra Energy, Inc.	NEE	14.00%	144,164	38.00%	54,782	217,500	40.00%	87,000	9.69%	1.046	14.65%
OGE Energy Corp.	OGE	13.00%	9,727	49.20%	4,786	10,400	50.00%	5,200	1.67%	1.008	13.11%
PPL Corporation	PPL	9.50%	30,925	49.00%	15,153	34,280	50.50%	17,311	2.70%	1.013	9.63%
Southern Company	SO	14.50%	87,500	36.00%	31,500	93,500	37.00%	34,595	1.89%	1.009	14.64%
Xcel Energy Inc.	XEL	11.50%	46,838	41.70%	19,531	67,200	39.50%	26,544	6.33%	1.031	11.85%
Mean											11.62%
Median											11.13%

Notes:
[1] Source: Value Line
[2] Source: Value Line
[3] Source: Value Line
[4] Equals [2] x [3]
[5] Source: Value Line
[6] Source: Value Line
[7] Equals [5] x [6]
[8] Equals ([7] / [4]) ^ (1/5) - 1
[9] Equals 2 x (1 + [8]) / (2 + [8])
[10] Equals [1] x [9]

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2025Q3	2025Q2	2025Q1	2024Q4	Average
Alliant Energy Corporation	LNT	52.59%	51.56%	52.68%	52.71%	52.38%
Ameren Corporation	AEE	53.32%	53.21%	53.67%	53.52%	53.43%
American Electric Power Company, Inc.	AEP	50.37%	49.52%	48.53%	48.58%	49.25%
Duke Energy Corporation	DUK	54.04%	52.44%	52.17%	53.08%	52.93%
Entergy Corporation	ETR	50.63%	49.89%	50.09%	51.30%	50.48%
FirstEnergy Corporation	FE	56.71%	58.52%	59.42%	58.94%	58.40%
Evergy, Inc.	EVRG	58.97%	58.09%	57.66%	59.43%	58.54%
IDACORP, Inc.	IDA	48.13%	47.54%	47.17%	49.95%	48.20%
NextEra Energy, Inc.	NEE	61.52%	60.64%	58.99%	59.98%	60.28%
OGE Energy Corporation	OGE	53.12%	53.14%	53.23%	53.25%	53.19%
PPL Corporation	PPL	54.58%	56.97%	56.91%	56.61%	56.27%
Southern Company	SO	55.05%	55.80%	54.75%	55.54%	55.29%
Xcel Energy Inc.	XEL	53.10%	53.38%	53.92%	54.24%	53.66%
MEAN		54.01%	53.90%	53.78%	54.39%	54.02%
MEDIAN		53.32%	53.21%	53.67%	53.52%	53.43%
LOW		48.13%	47.54%	47.17%	48.58%	48.20%
HIGH		61.52%	60.64%	59.42%	59.98%	60.28%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2025Q3	2025Q2	2025Q1	2024Q4	Average
Interstate Power and Light Company	LNT	50.46%	49.34%	51.50%	51.73%	50.76%
Wisconsin Power and Light Company	LNT	55.22%	54.30%	54.04%	53.82%	54.34%
Ameren Illinois Company	AEE	54.80%	56.13%	55.69%	55.36%	55.50%
Union Electric Company	AEE	52.05%	50.71%	51.89%	51.92%	51.64%
AEP Texas, Inc.	AEP	44.27%	44.24%	42.48%	43.47%	43.62%
Appalachian Power Company	AEP	51.15%	50.75%	50.81%	50.26%	50.74%
Indiana Michigan Power Company	AEP	52.45%	51.43%	50.21%	50.18%	51.07%
Kentucky Power Company	AEP	49.06%	48.66%	42.35%	44.93%	46.25%
Kingsport Power Company	AEP	52.37%	53.04%	53.15%	52.99%	52.89%
Ohio Power Company	AEP	52.18%	51.56%	51.05%	50.95%	51.44%
Public Service Company of Oklahoma	AEP	50.24%	46.45%	49.68%	48.32%	48.67%
Southwestern Electric Power Company	AEP	56.20%	55.19%	51.86%	51.55%	53.70%
Wheeling Power Company	AEP	46.38%	46.00%	45.11%	44.66%	45.54%
South Carolina Electric & Gas Co.	D	53.55%	52.87%	52.58%	53.14%	53.04%
Virginia Electric and Power Company	D	55.54%	55.59%	52.44%	53.46%	54.26%
Duke Energy Carolinas, LLC	DUK	52.99%	51.15%	50.72%	51.08%	51.49%
Duke Energy Florida, LLC	DUK	55.01%	53.16%	52.42%	53.67%	53.57%
Duke Energy Indiana, LLC	DUK	53.21%	52.67%	53.81%	53.41%	53.28%
Duke Energy Kentucky, Inc.	DUK	50.86%	55.33%	55.03%	54.31%	53.88%
Duke Energy Ohio, Inc.	DUK	62.74%	62.01%	63.14%	62.72%	62.65%
Duke Energy Progress, LLC	DUK	52.18%	50.00%	49.34%	51.71%	50.81%
Entergy Arkansas, Inc.	ETR	47.70%	46.70%	47.63%	47.15%	47.29%
Entergy Louisiana, LLC	ETR	53.84%	53.23%	53.57%	54.22%	53.71%
Entergy Mississippi, Inc.	ETR	47.14%	46.00%	45.18%	49.50%	46.95%
Entergy New Orleans, LLC	ETR	47.86%	49.49%	48.86%	48.50%	48.67%
Entergy Texas, Inc.	ETR	48.27%	47.35%	46.76%	49.74%	48.03%
Connecticut Light and Power Company	ES	54.20%	54.07%	53.86%	56.06%	54.55%
NSTAR Electric Company	ES	54.54%	53.86%	53.25%	57.43%	54.77%
Public Service Company of New Hampshire	ES	54.38%	53.54%	57.74%	56.37%	55.51%
Atlantic City Electric Company	EXC	50.06%	50.09%	50.08%	50.02%	50.06%
Baltimore Gas and Electric Company	EXC	51.72%	49.67%	52.66%	51.98%	51.51%
Commonwealth Edison Company	EXC	53.93%	53.62%	55.00%	54.70%	54.31%
Delmarva Power & Light Company	EXC	50.23%	50.20%	50.24%	50.28%	50.24%
PECO Energy Company	EXC	52.22%	55.85%	55.85%	53.46%	54.34%
Potomac Electric Power Company	EXC	50.12%	50.08%	50.12%	50.19%	50.13%
Evergy Metro	EVRG	51.83%	51.11%	50.87%	50.97%	51.19%
Evergy Missouri West, Inc.	EVRG	54.41%	52.67%	52.30%	52.08%	52.86%
Westar Energy (KPL)	EVRG	55.63%	54.67%	54.13%	57.12%	55.39%
Evergy Kansas Central, Inc.	EVRG	65.52%	64.79%	64.37%	66.78%	65.37%
Cleveland Electric Illuminating Company	FE	66.32%	67.36%	67.34%	67.19%	67.05%
Jersey Central Power & Light Company	FE	57.98%	68.35%	68.06%	67.97%	65.59%
FirstEnergy Pennsylvania Electric Company	FE	N/A	53.76%	53.15%	52.71%	53.21%
Metropolitan Edison Company	FE	N/A	N/A	N/A	N/A	
Monongahela Power Company	FE	54.86%	54.25%	53.79%	53.58%	54.12%
Ohio Edison Company	FE	50.59%	49.52%	55.77%	54.89%	52.70%
Pennsylvania Electric Company	FE	N/A	N/A	N/A	N/A	
Pennsylvania Power Company	FE	N/A	N/A	N/A	N/A	
Potomac Edison Company	FE	50.79%	50.44%	55.33%	51.72%	52.07%
Toledo Edison Company	FE	50.26%	50.25%	55.82%	55.44%	52.94%
West Penn Power Company	FE	N/A	N/A	N/A	N/A	
Idaho Power Co.	IDA	48.13%	47.54%	47.17%	49.95%	48.20%
Florida Power & Light Company	NEE	61.52%	60.64%	58.99%	59.98%	60.28%
Oklahoma Gas and Electric Company	OGE	53.12%	53.14%	53.23%	53.25%	53.19%
Arizona Public Service Company	PNW	52.23%	54.08%	52.22%	52.22%	52.69%
Kentucky Utilities Company	PPL	50.61%	55.33%	54.75%	54.48%	53.79%
Louisville Gas and Electric Company	PPL	48.71%	54.51%	53.76%	53.69%	52.67%
Narragansett Electric Company	PPL	62.85%	62.86%	63.29%	62.90%	62.97%
PPL Electric Utilities Corporation	PPL	56.29%	56.39%	56.66%	56.29%	56.41%
Alabama Power Company	SO	53.94%	54.43%	53.91%	53.88%	54.04%
Georgia Power Company	SO	55.64%	56.67%	55.24%	56.53%	56.02%
Mississippi Power Company	SO	55.32%	54.76%	54.56%	55.31%	54.99%
Northern States Power Company - MN	XEL	52.35%	51.27%	54.21%	53.37%	52.80%
Northern States Power Company - WI	XEL	52.27%	51.34%	54.03%	53.23%	52.72%
Public Service Company of Colorado	XEL	53.40%	55.21%	53.09%	55.21%	54.23%
Southwestern Public Service Company	XEL	54.25%	54.26%	55.34%	54.17%	54.50%

Notes:
[1] Ratios are weighted by actual common capital, preferred capital, and long-term debt of Operating Subsidiaries.
[2] Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2025Q3	2025Q2	2025Q1	2024Q4	Average
Alliant Energy Corporation	LNT	47.41%	48.44%	47.32%	47.29%	47.62%
Ameren Corporation	AEE	46.68%	46.79%	46.33%	46.48%	46.57%
American Electric Power Company, Inc.	AEP	49.63%	50.48%	51.47%	51.42%	50.75%
Duke Energy Corporation	DUK	45.96%	47.56%	47.83%	46.92%	47.07%
Entergy Corporation	ETR	49.37%	50.11%	49.91%	48.70%	49.52%
FirstEnergy Corporation	FE	43.29%	41.48%	40.58%	41.06%	41.60%
Evergy, Inc.	EVRG	41.03%	41.91%	42.34%	40.57%	41.46%
IDACORP, Inc.	IDA	51.87%	52.46%	52.83%	50.05%	51.80%
NextEra Energy, Inc.	NEE	38.48%	39.36%	41.01%	40.02%	39.72%
OGE Energy Corporation	OGE	46.88%	46.86%	46.77%	46.75%	46.81%
PPL Corporation	PPL	45.42%	43.03%	43.09%	43.39%	43.73%
Southern Company	SO	44.95%	44.20%	45.25%	44.46%	44.71%
Xcel Energy Inc.	XEL	46.90%	46.62%	46.08%	45.76%	46.34%
MEAN		45.99%	46.10%	46.22%	45.61%	45.98%
MEDIAN		46.68%	46.79%	46.33%	46.48%	46.57%
LOW		38.48%	39.36%	40.58%	40.02%	39.72%
HIGH		51.87%	52.46%	52.83%	51.42%	51.80%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2025Q3	2025Q2	2025Q1	2024Q4	Average
Interstate Power and Light Company	LNT	49.54%	50.66%	48.50%	48.27%	49.24%
Wisconsin Power and Light Company	LNT	44.78%	45.70%	45.96%	46.18%	45.66%
Ameren Illinois Company	AEE	45.20%	43.87%	44.31%	44.64%	44.50%
Union Electric Company	AEE	47.95%	49.29%	48.11%	48.08%	48.36%
AEP Texas, Inc.	AEP	55.73%	55.76%	57.52%	56.53%	56.38%
Appalachian Power Company	AEP	48.85%	49.25%	49.19%	49.74%	49.26%
Indiana Michigan Power Company	AEP	47.55%	48.57%	49.79%	49.82%	48.93%
Kentucky Power Company	AEP	50.94%	51.34%	57.65%	55.07%	53.75%
Kingsport Power Company	AEP	47.63%	46.96%	46.85%	47.01%	47.11%
Ohio Power Company	AEP	47.82%	48.44%	48.95%	49.05%	48.56%
Public Service Company of Oklahoma	AEP	49.76%	53.55%	50.32%	51.68%	51.33%
Southwestern Electric Power Company	AEP	43.80%	44.81%	48.14%	48.45%	46.30%
Wheeling Power Company	AEP	53.62%	54.00%	54.89%	55.34%	54.46%
South Carolina Electric & Gas Co.	D	46.45%	47.13%	47.42%	46.86%	46.96%
Virginia Electric and Power Company	D	44.46%	44.41%	47.56%	46.54%	45.74%
Duke Energy Carolinas, LLC	DUK	47.01%	48.85%	49.28%	48.92%	48.52%
Duke Energy Florida, LLC	DUK	44.99%	46.84%	47.58%	46.33%	46.44%
Duke Energy Indiana, LLC	DUK	46.79%	47.33%	46.19%	46.59%	46.73%
Duke Energy Kentucky, Inc.	DUK	49.14%	44.67%	44.97%	45.69%	46.12%
Duke Energy Ohio, Inc.	DUK	37.26%	37.99%	36.86%	37.28%	37.35%
Duke Energy Progress, LLC	DUK	47.82%	50.00%	50.66%	48.29%	49.19%
Entergy Arkansas, Inc.	ETR	52.30%	53.30%	52.37%	52.85%	52.71%
Entergy Louisiana, LLC	ETR	46.16%	46.77%	46.43%	45.78%	46.29%
Entergy Mississippi, Inc.	ETR	52.86%	54.00%	54.82%	50.50%	53.05%
Entergy New Orleans, LLC	ETR	52.14%	50.51%	51.14%	51.50%	51.33%
Entergy Texas, Inc.	ETR	51.73%	52.65%	53.24%	50.26%	51.97%
Connecticut Light and Power Company	ES	45.80%	45.93%	46.14%	43.94%	45.45%
NSTAR Electric Company	ES	45.46%	46.14%	46.75%	42.57%	45.23%
Public Service Company of New Hampshire	ES	45.62%	46.46%	42.26%	43.63%	44.49%
Atlantic City Electric Company	EXC	49.94%	49.91%	49.92%	49.98%	49.94%
Baltimore Gas and Electric Company	EXC	48.28%	50.33%	47.34%	48.02%	48.49%
Commonwealth Edison Company	EXC	46.07%	46.38%	45.00%	45.30%	45.69%
Delmarva Power & Light Company	EXC	49.77%	49.80%	49.76%	49.72%	49.76%
PECO Energy Company	EXC	47.78%	44.15%	44.15%	46.54%	45.66%
Potomac Electric Power Company	EXC	49.88%	49.92%	49.88%	49.81%	49.87%
Evergy Metro	EVRG	48.17%	48.89%	49.13%	49.03%	48.81%
Evergy Missouri West, Inc.	EVRG	45.59%	47.33%	47.70%	47.92%	47.14%
Westar Energy (KPL)	EVRG	44.37%	45.33%	45.87%	42.88%	44.61%
Evergy Kansas Central, Inc.	EVRG	34.48%	35.21%	35.63%	33.22%	34.63%
Cleveland Electric Illuminating Company	FE	33.68%	32.64%	32.66%	32.81%	32.95%
Jersey Central Power & Light Company	FE	42.02%	31.65%	31.94%	32.03%	34.41%
FirstEnergy Pennsylvania Electric Company	FE	N/A	46.24%	46.85%	47.29%	46.79%
Metropolitan Edison Company	FE	N/A	N/A	N/A	N/A	
Monongahela Power Company	FE	45.14%	45.75%	46.21%	46.42%	45.88%
Ohio Edison Company	FE	49.41%	50.48%	44.23%	45.11%	47.30%
Pennsylvania Electric Company	FE	N/A	N/A	N/A	N/A	
Pennsylvania Power Company	FE	N/A	N/A	N/A	N/A	
Potomac Edison Company	FE	49.21%	49.56%	44.67%	48.28%	47.93%
Toledo Edison Company	FE	49.74%	49.75%	44.18%	44.56%	47.06%
West Penn Power Company	FE	N/A	N/A	N/A	N/A	
Idaho Power Co.	IDA	51.87%	52.46%	52.83%	50.05%	51.80%
Florida Power & Light Company	NEE	38.48%	39.36%	41.01%	40.02%	39.72%
Oklahoma Gas and Electric Company	OGE	46.88%	46.86%	46.77%	46.75%	46.81%
Arizona Public Service Company	PNW	47.77%	45.92%	47.78%	47.78%	47.31%
Kentucky Utilities Company	PPL	49.39%	44.67%	45.25%	45.52%	46.21%
Louisville Gas and Electric Company	PPL	51.29%	45.49%	46.24%	46.31%	47.33%
Narragansett Electric Company	PPL	37.15%	37.14%	36.71%	37.10%	37.03%
PPL Electric Utilities Corporation	PPL	43.71%	43.61%	43.34%	43.71%	43.59%
Alabama Power Company	SO	46.06%	45.57%	46.09%	46.12%	45.96%
Georgia Power Company	SO	44.36%	43.33%	44.76%	43.47%	43.98%
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Northern States Power Company - MN	XEL	47.65%	48.73%	45.79%	46.63%	47.20%
Northern States Power Company - WI	XEL	47.73%	48.66%	45.97%	46.77%	47.28%
Public Service Company of Colorado	XEL	46.60%	44.79%	46.91%	44.79%	45.77%
Southwestern Public Service Company	XEL	45.75%	45.74%	44.66%	45.83%	45.50%

Notes:
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[2] Operating Subsidiaries with data listed as N/A from SNL Financial have been excluded from the analysis.

REBUTTAL TESTIMONY
OF
KIMBUGWE A. KATEREGGA, PH.D.

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E–01345A–25–0105

March 2026

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REBUTTAL TESTIMONY
OF
KIMBUGWE A. KATEREGGA, PH.D.
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E–01345A–25–0105

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kimbugwe A. Kateregga. My business address is 17595 S. Tamiami Trail, Suite 260, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am a partner of Foster Associates Consultants, LLC. Foster Associates is a public utility economic consulting firm offering economic research and consulting services on issues arising from governmental regulation of utilities. Areas of specialization supported by the firm's Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND.

A. I was awarded a B.Sc. (Eng.) degree in Civil Engineering from Makerere University, an M.Sc. degree in Management Science from the University of Wales and a Ph.D. degree in Engineering Valuation from Iowa State University. I have taught college level courses in statistics and mathematics and conducted courses in depreciation and public utility economics for clients of Foster Associates.

I have prepared and presented a number of papers at conferences and have published several articles on matters relating to depreciation, technological forecasting, valuation, and economics. I am a member of Phi Kappa Phi academic honor society, the Society of Depreciation Professionals, and an associate member of the American Gas Association – Edison Electric Institute.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined Foster Associates in 1986 as a consultant and specialist in depreciation. Prior to joining Foster Associates, I was employed as a Research Assistant at Iowa State University. I served under contract in this capacity between 1983 and 1986 to investigate marginal cost pricing issues and the application of technological forecasting models in predicting the service life of industrial property. The findings of this research have been implemented in the telecommunications industry.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in proceedings before the Arizona Corporation Commission (Commission) and before the Arkansas, Maryland, Massachusetts, Michigan, Montana, New Jersey, New York, and Rhode Island public service commissions and boards. A more detailed description of my professional qualifications is contained in Attachment KAK–1.

II. OVERVIEW

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to (i) adopt in full the pre−filed testimony of Dr. Ronald E. White who is unable to appear in this proceeding because of personal circumstances and (ii) to respond to portions of the pre–filed direct testimony of witnesses Paul J. Alvarez on behalf of AARP, Brian C. Andrews on behalf of Federal Executive Agencies (FEA), and David J. Garrett on behalf of the Arizona Large Customer Group and Freeport Minerals Corporation. In particular, I was asked to address depreciation rate adjustments advocated by the three witnesses to the rates developed by Foster Associates in the 2024 depreciation study filed in this proceeding.

Q. PLEASE SUMMARIZE THE SCOPE OF YOUR REBUTTAL TESTIMONY.

A. Foster Associates developed depreciation rates in support of Arizona Public Service's (APS) filing in this matter with no intent to either increase or decrease depreciation expense. As reported in Dr. White's direct testimony, Foster Associates did not conduct a statistical service life analysis. Recommended rates were derived using

projection life curves estimated and adopted in APS's 2019 study.[1] Conducting studies in the 2024 study would be a circular exercise because of the Company's adoption of "mortality curve" methods for aging of retirements in 2021 (hereafter referred to as automatic aging or automated methods). Neither witness Andrews nor witness Garrett has claimed or demonstrated that the rates recommended for APS are mathematically incorrect, inconsistent with the goals of depreciation accounting, or fall outside a zone of reasonableness. Notwithstanding witness Andrews' acknowledgement of circularity, he proceeded to conduct a circular analysis of the mortality curve retirements generated from automatic aging. Witness Garrett did not acknowledge or recognize circularity; he simply conducted a circular analysis of mortality curve retirements. The remainder of my rebuttal testimony will address the erroneous service–life studies conducted by witnesses Andrews and Garrett, and recommendations and adjustments advocated by all three witnesses for no apparent reason than to reduce depreciation expense.

Q. WHAT IS THE STANDARD THAT SHOULD BE APPLIED IN EVALUATING APPROPRIATE DEPRECIATION RATES?

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone. If some other standard—such as reducing revenue requirements or increasing internal cash generation—is considered more important in setting depreciation rates, then cost allocation theory must be abandoned as the foundation for depreciation accounting.

This is not to suggest that regulation is prohibited from using depreciation or other expense reduction measures to achieve social policy objectives such as reducing utility rates to benefit current customers. These measures, however, have consequences. Reducing internal cash generation by reducing depreciation expense,

[1] Direct Testimony of Dr. Ronald E. White p. 7, l. 19-29.

for example, can increase the marginal cost of external financing and potentially restrict future access to the capital markets.

If, however, regulation chooses to use depreciation expense to achieve a desired social objective, depreciation rates and expense should be derived to achieve that objective.

III. REBUTTAL TO WITNESS PAUL J. ALVAREZ

Q. WHAT AJUSTMENT IS MR. ALVAREZ PROPOSING TO APS'S DEPRECIATION RATES?

A. Mr. Alvarez observed that APS is proposing a $31.5 million increase in Nuclear Plant depreciation. He claimed that in discovery, "[t]he Company provided no support for the increase in its response, other than to say that 'Changes in depreciation expense are impacted by many factors' and 'the most notable impact is the change in the amortization period applied to Palo Verde excess reserves'"[2]. Based on that claim, Mr. Alvarez recommended that "… the Commission reject this requested increase in its entirety due to a lack of support for the increase provided by the Company."[3]

Q. WAS THE COMPANY'S RESPONSE INADEQUATE AS CLAIMED BY MR. ALVAREZ?[4]

A. No. The Company's response attributing the most notable impact to a revised amortization period is what caused the observed increase.

Q. WOULD YOU PLEASE EXPLAIN?

A. In his rebuttal testimony in the 2019 study, Dr. White stated:

> *It is my understanding that, after considering the direct testimony of intervenors, the Company sought ways to mitigate the impact of the rate increase request on its customers after its initial rate Application was filed. In concert with other mitigation measures, Foster Associates was requested to reduce depreciation rates by: a) Extending the life–span of non–legacy solar power stations by 10 years; and b)* ***reducing the***

[2] Direct Testimony of Witness Alvarez at p. 47, l. 6.
[3] *Id* at p. 48, l. 6-7.
[4] *Id* at p. 47, l. 18-19, p. 48, l.1-2.

> ***amortization period of the Palo Verde reserve excess from nine to six years*** *[Emphasis added].*[5]

By reducing the amortization period of the excess reserve, the Palo Verde depreciation rate was reduced from 0.96 percent to 0.31 percent.[6] With the expiration of the mitigation rate, the computation of the current accrual rate reverts to a remaining–life amortization of any reserve imbalance and, therefore, the higher depreciation accrual rate. It is important to recognize that it is not the proposed 1.33 percent rate[7] in the 2024 study by itself that is causing the $31.5 million increase but rather the difference from the 0.31 percent mitigation rate in the 2019 study that was lower than a comparable remaining–life rate.

Q. SHOULD THE COMMISSION ACCEPT MR. ALVAREZ'S ADJUSTMENT?

A. No.

IV. REBUTTAL TO WITNESS BRIAN C. ANDREWS

Q. HOW DOES MR. ANDREWS DESCRIBE APS'S DEPRECIATION STUDY?

A. Mr. Andrews states that "I do take issue with the lack of a life analysis in APS' depreciation study."[8] Mr. Andrews states further that "I have conducted an actuarial life analysis on several of APS' largest distribution and general plant accounts. Specifically, APS' proposed depreciation rates for nine accounts are overstated and burden APS' customers with unnecessary and excessive depreciation expense."[9] Mr. Andrews did not adjust any of APS's proposed net salvage rates.

Q. ACCORDING TO MR. ANDREWS, "THE BASIC UNDERLYING PRINCIPLE OF UTILITY DEPRECIATION ACCOUNTING IS INTERGENERATIONAL EQUITY, WHERE THE CUSTOMERS/RATEPAYERS WHO BENEFIT FROM THE SERVICE OF

[5] Rebuttal Testimony of Dr. Ronald E. White, Docket No. E-01345A-19-0236, p. 12, l.28-29, p. 13, l. 1-4.
[6] *Id* at p. 13, Table 2.
[7] Direct Testimony of Dr. Ronald E. White p. 10, Table 2.
[8] Direct Testimony of Witness Andrews at p. 18, l. 12-15.
[9] *Id* at p. 18, l. 6-10.

ASSETS PAY ALL THE COSTS FOR THOSE ASSETS DURING THE BENEFIT PERIOD, WHICH IS OVER THE LIFE OF THOSE ASSETS."[10] DO YOU AGREE THAT "INTERGENERATIONAL EQUITY" IS THE BASIC UNDERLYING PRINCIPLE OF UTILITY DEPRECIATION ACCOUNTING?

A. No. The concept of intergenerational equity is meaningless with group depreciation accounting. Any given generation of ratepayers is served by a mix of plant investments of varying ages. Some plant will be old and may be retired in the near future. Other facilities will be relatively new and may or may not be retired before older facilities are replaced. This phenomenon—called *retirement dispersion*—is implicitly captured in vintage–group (and broad–group) depreciation rates. Plant retired before the average service life of the group will be under–depreciated and plant remaining in service beyond the average will be over–depreciated to compensate for under–accruals on earlier retirements. Current customers are always paying for revenue requirements on retired plant and equipment from which prior customers may have received utility service.

The straight–line method of depreciation also contributes to intergenerational subsidies by imposing higher revenue requirements on current customers than on future customers receiving identical service from the same physical plant. A declining pattern of revenue requirements is caused by a declining sum of depreciation and return on rate base. Intergenerational subsidies cannot be eliminated when revenue requirements are derived using group depreciation accounting and the straight–line method of cost allocation. The cost burden assigned to varying generations of ratepayers is a consequence of group depreciation accounting and the method chosen to allocate costs.

A. Mortality Curve Retirements

Q. WHAT IS YOUR UNDERSTANDING OF MR. ANDREW'S CRITICISM OF FOSTER ASSOCIATES' DECISION TO NOT CONDUCT A SERVICE LIFE ANALYSIS FOR APS IN THIS STUDY?

[10] *Id* at p. 5, l. 8-11.

A. Mr. Andrews acknowledges the automated method for vintaging post–2020 retirements[11]. He, however, argues that Foster Associates should have conducted a service life analysis for the following reasons: (i) APS has only implemented automated methods "… for the last few years rather than the majority of the property record"[12] and that "While Dr. White's concern about the circularity introduced by automated vintaging of post-2019 retirements is valid, this issue affects only a limited portion of the overall retirement record."[13] (ii) "Without conducting updated life analyses, there is no empirical basis for validating the service life estimates that APS proposes in this proceeding."[14] (iii) Foster Associates retention of parameters approved by this Commission in the 2019 study "… assumed that nothing has changed in the retirement patterns, operating conditions, or technological environment affecting APS' plant over the past several years."[15] (iv) the retention of parameters from the 2019 Commission order further "… assumes that the survivor curves approved from the 2019 study were absolutely accurate. This is not a reasonable assumption and should not be accepted without analytical verification."[16]

Q. DO YOU AGREE WITH MR. ANDREWS' CLAIM THAT FOSTER ASSOCIATES SHOULD HAVE CONDUCTED A SERVICE LIFE ANALYSIS BECAUSE APS HAS ONLY IMPLEMENTED AUTOMATED METHODS FOR THE LAST FEW YEARS?

A. No. Probabilities of retirement measured and estimated in a service life analysis are highly dependent on a number of variables. Any variation in either the age, the exposure, or the magnitude of retirement will impact the estimated probability of retirement at that age. Mr. Andrews' aggregation of retirements into two groups of pre– and post–2019 as displayed in Table 2 of his testimony[17] ignores estimation

[11] *Id* at p. 16, l. 8-14; p. 17, l. 1-7.
[12] *Id* at p. 14, l. 10-11.
[13] *Id* at p. 15, l. 18-20.
[14] *Id* at p. 15, l. 10-12.
[15] *Id* at p. 15, l.13-15.
[16] *Id* at p. 15, l. 15-17.
[17] *Id* at p. 16. Mr. Andrews' identification of 2020–2023 in Table 2 as the period with automated aging is wrong. APS started mortality curve methods in January 2021. Foster Associates' criticism of Mr. Andrews' conclusions would apply equally to a corrected Table 2.

biases attributable to the underlying variables. What he discounts as only approximately 16 percent of the retirement history in post–2019 retirement activity is highly significant in a service life analysis. If Mr. Andrews accepts that post–2019 retirement activity affects only a limited portion of the overall retirement record, he should then accept Foster Associates' decision to retain the current parameters based on the 84 percent pre–2019 retirement activity that he considers more significant.

Q. DO YOU AGREE WITH MR. ANDREWS' ASSERTION THAT "WITHOUT CONDUCTING UPDATED LIFE ANALYSES, THERE IS NO EMPIRICAL BASIS FOR VALIDATING THE SERVICE LIFE ESTIMATES THAT APS PROPOSES IN THIS PROCEEDING"[18]?

A. No, I do not. Mr. Andrews concluded from Table 2 of his testimony that "The remaining 84% of the retirement history is unaffected by the automated vintaging process and remains a sound basis for actuarial analysis"[19]. This conclusion supports the decision made by Foster Associates to not conduct a new service life analysis and retain the parameters from the 2019 study that were based on that 84 percent activity. The APS database used in the 2019 study is the best data available. The parameters estimated in the 2019 study which were based on that data and approved by the Commission are the best parameters available to develop new depreciation rates for APS. The claim of a lack of empirical basis is therefore unfounded.

Q. DO YOU AGREE WITH MR. ANDREWS' ASSERTION THAT FOSTER ASSOCIATES' RETENTION OF PARAMETERS APPROVED BY THIS COMMISSION IN THE 2019 STUDY "… ASSUMED THAT NOTHING HAS CHANGED IN THE RETIREMENT PATTERNS, OPERATING CONDITIONS, OR TECHNOLOGICAL ENVIRONMENT AFFECTING APS' PLANT OVER THE PAST SEVERAL YEARS"?

[18] *Id* at p. 15, l. 10-12.
[19] *Id* at p. 16, l. 4-6.

A. I do not. Nothing in Foster Associates' recommendation implies such assumptions. Foster Associates retained current parameters to avoid circularity in estimating parameters used in the formulation of depreciation rates.

Q. DO YOU AGREE WITH MR. ANDREWS' ASSERTION THAT THE RETENTION FURTHER "… ASSUMES THAT THE SURVIVOR CURVES APPROVED FROM THE 2019 STUDY WERE ABSOLUTELY ACCURATE. THIS IS NOT A REASONABLE ASSUMPTION AND SHOULD NOT BE ACCEPTED WITHOUT ANALYTICAL VERIFICATION"?

A. I do not. Nothing in Foster Associates' recommendation implies such an assumption. Foster Associates clearly stated that life estimation "… is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future."[20] It is irrational for Mr. Andrews to claim that parameters based on random sampling of the historical record, informed judgment, and unconfirmed expectations of the future can be viewed as "absolutely accurate".

B. Estimation of Service–Life Statistics

Q. HOW DOES MR. ANDREWS PROPOSE TO REDUCE THE COMPANY'S REQUESTED DEPRECIATION EXPENSE BY $34.34 MILLION?

A. Mr. Andrews achieved the $34.34 million reduction by lengthening service–lives for nine plant accounts from those retained by Foster Associates from the 2019 Commission order.[21] His adjustments to service–lives were derived from analyses of the full plant activity record including post–2020 transactions of mortality curve retirements.

[20] Direct Testimony of Dr. Ronald E. White, Attachment REW–2DR, p. 9-10.
[21] Direct Testimony of Witness Andrews at p. 37, l. 4-7, 11-13.

Q. OTHER THAN AN ANALYSIS BASED ON MORTALITY CURVE RETIREMENTS, DOES MR. ANDREWS' SERVICE LIFE ANALYSIS HAVE ADDITIONAL PROBLEMS?

A. Yes. Mr. Andrews uses what he calls a statistical fit "lower SSD"[22] criterion to compare the projection life curves from the 2019 study with his proposed projection life curves developed at the end of 2023. Comparing recommendations developed at two different points in time is unrealistic and erroneous and may explain his conclusion that "For each of the nine accounts where I am proposing a survivor curve that differs from Dr. White's recommendation, the SSD is lower. That is, all of my recommendations result in survivor curves that mathematically and statistically fit APS' data better than those recommended by Dr. White."[23]

Another problem is Mr. Andrews' fitting of survivor curves to observed proportions surviving. Although he calls his method mathematical, it is nothing more than a computerized version of a visual curve fitting technique. Visual curve fitting is an application of descriptive statistics used to summarize and describe data through numerical calculations, graphs, or tables. It is not an actuarial method of life analysis.

The statistical method used by Foster Associates is an application of inferential statistics. Hazard rates are graduated or smoothed rather than "visually" fitting data points to a survivor curve. This method draws inferences and predictions about population service–life parameters based on an analysis of samples drawn from a parent population. Beside the different points in time of his analysis versus when Foster Associates conducted the 2019 study, it is misleading to compare projection life curves developed from hazard rates and inferential statistics to those developed from descriptive statistics and "mathematical" visual curve fitting.

Q. ACCORDING TO MR. ANDREWS, "IF, HOWEVER, THE USE OF AUTO-VINTAGING IS TO CONTINUE, THEN AT A MINIMUM THE SURVIVOR CURVES USED AS INPUTS TO THE VINTAGING PROCESS SHOULD BE

[22] *Id* at p. 19, l. 2-21.
[23] *Id* at p. 20, l. 6-9.

UPDATED REGULARLY THROUGH PROPER LIFE ANALYSIS TO ENSURE THEY REFLECT THE BEST AVAILABLE ESTIMATE FOR ACTUAL SERVICE LIFE PATTERNS, RATHER THAN SIMPLY CARRYING FORWARD CURVES FROM A PRIOR STUDY INDEFINITELY".[24] DO YOU AGREE?

A. No. Mr. Andrews' recommendation demonstrates a logical inconsistency in addressing the automatic aging issue. As noted above, Mr. Andrews acknowledged that in automatic aging, "Rather than reflecting actual, verifiable information about when retired property was originally placed in service, the retirement record becomes a product of the survivor curve assumptions already embedded in the system. This creates a circular relationship between the data and the assumptions that are supposed to be tested through periodic depreciation studies. The curves drive the vintaging of retirements, and the resulting retirement data then reflects those same curve assumptions back to the analysis. Any analysis performed on such data will merely confirm the inputs rather than provide independent insight into actual service life experience."[25] The recommendation to update the survivor curves regularly through proper life analysis is inconsistent with the Mr. Andrews' circularity observation. Moreover, even if such survivor curves could be developed by methods not directly applied to mortality curve retirements, Mr. Andrews fails to recognize that those curves would then be used in the computation of average service lives, remaining lives, and depreciation accrual rates. Mr. Andrews' recommendation is illogical and should likewise be rejected by this Commission.

Q. IN YOUR OPINION, SHOULD THE COMMISSION ACCEPT MR. ANDREWS' ESTIMATED SERVICE LIVES AND ACCRUAL ADJUSTMENTS FOR THESE NINE ACCOUNTS?

A. Not at all. Mr. Andrews' reliance on a mixed population of retirements (*i.e.*, heterogeneity) comprising about 84 percent actual aging and 16 percent automatic aging is a flawed and misleading service life analysis. Both Foster Associates and Mr.

[24] *Id* at p. 17, l. 23; p.18, l. 1-4.
[25] *Id* at p. 16, l. 13-14; p. 17, l. 1-7.

Andrews agree, as explained above, that the circularity introduced by automatic aging cannot support a meaningful service–life analysis. Mr. Andrews' adjustments and recommendations should, therefore, be rejected by this Commission.

V. REBUTTAL TO WITNESS DAVID J. GARRETT

Q. WHAT IS THE "BURDEN OF PROOF" STANDARD CLAIMED BY MR. GARRETT AS THE "STANDARD BY WHICH REGULATED UTILITIES ARE ALLOWED TO RECOVER DEPRECIATION EXPENSE?"

A. According to Mr. Garrett, the Supreme Court in *Lindheimer v. Illinois Bell Telephone Company* enunciated the following standard:

> *[T]he Company has the burden of proof of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion.*[26]

Q. IS THIS YOUR UNDERSTANDING OF THE BURDEN A REGULATED UTILITY MUST SATISFY BEFORE BEING ALLOWED TO RECOVER DEPRECIATION EXPENSE?

A. No. It is my understanding that *Lindheimer v. Illinois Bell Telephone Co*., 292 U.S. 151, 169 (1934) was a case arising from an initial appeal of an Illinois Commerce Commission service rate order that Illinois Bell claimed would be confiscatory if enforced. The opening phrase of the language omitted by Mr. Garrett in his quotation from the case reads:

> ***Confiscation being the issue**, the Company has the burden of proof making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. (Emphasis added).*

Confiscation is neither an issue here nor was it considered in the formulation of depreciation rates recommend in the 2024 depreciation study.

[26] Witness Garrett Direct Testimony at p. 62, l. 6–16.

The Court decreed that amounts charged to operating expense and credited to the depreciation reserve are "excessive" to the extent that ratepayers are required to provide capital contributions for additional plant and equipment upon which a utility expects a return. The Court did not create a new standard or decree that the Company must make a convincing showing "… its proposed depreciation rates are not excessive."[27] No regulated utility could meet such a vague standard.

Q. HOW DOES MR. GARRETT PROPOSE TO REDUCE THE COMPANY'S REQUESTED DEPRECIATION EXPENSE BY $54.76 MILLION?

A. Mr. Garrett achieved a $54.76 million reduction by lengthening service lives for seven plant accounts from those retained by Foster Associates from the 2019 order.[28] His adjustments to service–lives were derived from analyses of the full plant activity record including post–2020 mortality curve retirements.

Q. DOES MR. GARRETT ACKNOWLEDGE THAT RETIREMENTS ARE NOW AUTOMATED IN THE COMPANY'S HISTORICAL RECORD?

A. He does not.

Q. DOES MR. GARRETT ACKNOWLEDGE THAT FOSTER ASSOCIATES RETAINED PARAMETERS DEVELOPED IN THE 2019 STUDY?

A. He does not.

Q. DOES MR. GARRETT USE "MATHEMATICAL" VISUAL CURVE FITTING AS MR. ANDREWS?

A. Yes, He does. Mr. Garrett states that "The curve-fitting process involves selecting the best Iowa curve to fit the OLT [observed life table] curve. This can be accomplished through a combination of visual and mathematical curve-fitting techniques."[29]

[27] *Id* at p. 62, l. 18-19.
[28] *Id* at p. 79, l. 19-22; p. 80, l. 1-4.
[29] *Id* at p. 64, l. 11-14.

Q. OTHER THAN SIMILARITIES WITH MR. ANDREWS' SERVICE LIFE ANALYSIS, DOES WITNESS GARRETT HAVE OTHER PROBLEMS IN HIS RECOMMENDATIONS?

A. Yes. Mr. Garrett is apparently unaware or ignores that APS uses a depreciation system composed of the straight–line method, vintage–group procedure, and remaining–life technique approved by this Commission. The $54.76 million reduction Mr. Garrett is recommending is based on the "… straight-line method, the average life procedure, the remaining life technique, and the broad group model."[30] Nowhere in his testimony does Mr. Garrett explain or support why this Commission should change the depreciation system currently approved for APS.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN A BROAD–GROUP PROCEDURE AND A VINTAGE–GROUP PROCEDURE.

A. A depreciation procedure identifies the level of grouping or sub–grouping of assets classified in a plant category. The level of grouping specifies the weighting used to obtain composite service–life statistics for a plant account.

The distinction between the broad–group and vintage–group procedures is how average service lives are estimated for each vintage. Each vintage is assumed to have the same average service life (equal to the projection life) using the broad–group procedure.[31] The vintage–group procedure distinguishes average service lives among vintages and provides cost apportionment over either the estimated weighted–average remaining life or average service–life of a rate category.

Q. DID MR. GARRETT USE A BROAD–GROUP PROCEDURE FOR ALL PLANT ACCOUNTS IN THE 2024 STUDY?

A. No. Mr. Garrett used a broad–group procedure for the seven plant accounts in which he lengthened estimated service lives. He retained the vintage–group procedure used by Foster Associates for all remaining plant accounts. Mr. Garrett cannot defend his using a mixed or inconsistent formulation of depreciation rates.

[30] *Id* at p. 63, l. 12-13.

[31] A *projection life* is the estimated mean service life of the population from which observed retirements are viewed as a random sample.

Q. DID YOU IDENTIFY ADDITIONAL ERRORS IN MR. GARRETT'S FORMULATION OF ACCRUAL RATES?

A. Yes. Mr. Garrett's treatment of depreciation reserves contains significant and critical errors. As discussed in White direct testimony and Attachment REW–2DR, depreciation reserves were rebalanced in the 2024 depreciation study (as rebalanced in all prior APS studies) to reduce offsetting reserve imbalances and increase depreciation rate stability. Recorded reserves were rebalanced by multiplying the calculated reserve for each primary account by the ratio of total recorded reserves to total calculated reserves. The sum of redistributed reserves is equal, therefore, to total recorded reserves before redistribution. Reserves for amortizable categories were adjusted by replacing recorded reserves with current measured theoretical reserves and distributing any reserve imbalances to depreciable categories. Rebalanced reserves, therefore, are a function of the parameters (*i.e.*, service lives and net salvage rates) used in the formulation of computed reserves.

Mr. Garrett did not object to redistributing reserves in this proceeding, but he incorrectly used rebalanced reserves derived in the 2024 study as recorded reserves in his computation of remaining–life accrual rates. His advocated adjustments to the recommended service lives, however, would necessitate a re–computation of theoretical reserves for these accounts and a second rebalancing of recorded reserves over all plant accounts. Mr. Garrett cannot defend retaining accrual rates derived in the 2024 study for his "non–adjusted" plant accounts when he adjusted service lives for selected accounts within the same function. In short, Mr. Garrett's recommended depreciation rates and accruals are derived incorrectly.

Q. SHOULD THE COMMISSION ACCEPT MR. GARRETT'S ESTIMATED SERVICE LIVES FOR THE SEVEN ACCOUNTS?

A. No. Mr. Garrett's reliance on a mixed population of retirements comprising actual aging and automatic aging completely invalidates his service life analysis. The criticism to Mr. Andrews' adjustments equally apply to Mr. Garrett's adjustments and should likewise be rejected in this proceeding.

Q. SHOULD THE COMMISSION ACCEPT MR. GARRETT'S RECOMMENDED DEPRECIATION RATES AND ACCRUALS?

A. No. Mr. Garrett's formulation of a hybrid depreciation system comprising a vintage–group and a broad–group procedure and his failure to rebalance reserves properly further invalidate his recommended accrual rates and accruals. All Mr. Garrett's recommendations should be rejected in this proceeding.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.