DIRECT TESTIMONY OF JAMIE R. MOE

On Behalf of Arizona Public Service Company

Docket No. E-01345A-22-0144

October 28, 2022

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ATTACHMENT LIST

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

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. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have over 19 years of experience in the utility industry. From 2003 to 2006, I served as a Staff Analyst with the Arizona Corporation Commission (ACC or Commission). From 2007 to 2009, I worked for Global Water Resources as a Regulatory Analyst, and from 2015 to 2017, I worked for Arizona Water Company as Manager of Rates and Regulation. I originally joined APS in 2010 as a Senior Rate and Regulatory Analyst and returned in 2017 as Rate Strategy Consultant and later as Rate Strategy Advisor. I now manage the Company's Rate Design and Revenue Requirements teams, which are responsible for analyzing and aligning costs with appropriate pricing structures. I have a Bachelor of Science degree in Accounting from North Dakota State University.

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

A. Yes. I have testified at the Commission for ACC Staff and Global Water Resources, Inc.

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

A. My Direct Testimony supports APS's application regarding the following:

- Standard Filing Requirement Schedules (SFRs) A-1, portions of A-2, B-1, B-2, B-3, B-4a, C-1, C-2, F-1 SFR Schedules, and all G SFR Schedules;
- APS's Cost of Service Studies (COSS);
- Proposed changes to the Cost of Service (COS) for residential solar customers, as well as the differences in cost allocation using site load and delivered load; and
- Fair Value Increment (FVI) and Fair Value Rate of Return (FVROR).

II. <u>SUMMARY</u>

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My Direct Testimony addresses certain SFR schedules including SFR Schedule A-1, which calculates the increase in APS's base rate revenue requirements of $772.3 million. I discuss the steps required to implement the rate adjustment mechanism proposal that is more fully described by APS witnesses Jessica Hobbick and Theodore Geisler, which includes the elimination of the Lost Fixed Cost Recovery (LFCR) and the Environmental Improvement Surcharge (EIS) adjustment mechanisms. The base rate revenue increase includes APS's proposal to transfer $107.83 million in collections from adjustment mechanisms into base rates, a concurrent change to the PSA rate reduction of $220.59 million, and a concurrent REAC revenue increase of $ 16.09 million. These adjustor transfers do not change the total amount collected from customers but rather would move the following revenues into base rates:

1. A portion of the energy efficiency expense currently collected in the Demand Side Management Adjustment Charge (DSMAC), in the amount of $39.0 million (ACC jurisdiction less revenue credits);

2. A portion of the lost fixed costs currently collected through the LFCR mechanism, in the amount of $58.5 million (ACC jurisdiction); and
3. The revenue requirement for environmental compliance currently collected in the EIS, in the amount of $10.3 million (ACC jurisdiction less revenue credits).

The following Day-One[1] changes to adjustors will also occur outside of costs transferred to base rates and have additional impact to the net impact on customer bills:

1. A portion of the deferred fuel-related revenues currently collected in the Power Supply Adjustor (PSA), in the amount of $220.6 million (ACC jurisdiction), will be reflected in a lower PSA rate; and
2. The revenue requirement for the Renewable Energy Adjustment Charge (REAC) will increase by the amount of $16.1 million related to Coal Community Transition (CCT) (ACC jurisdiction);

Figure 1 below shows the components of the Company's proposed base rate increase, inclusive of adjustor transfers and deferred Test Year fuel costs.

[1] Day One changes refer to changes in adjustor rates that will occur the same day that new base rates are implemented in this rate case.

Figure 1. Total Net Bill Impact[2]

Net Impact = Net Base Rate Increase + Net Adjustor Changes	**Dollars**	**Bill Impact**
Base Rate Increase		
Total Revenue Deficiency	$772.27M	22.87%
Adjustor Transfers	($107.83M)	(3.19%)
Base Rate Increase Net of Adjustors	$664.44M	19.68%
Day-One Power Supply Adjustment (PSA) Revenue Reduction	($220.59M)	(6.53%)
Day-One Renewable Energy Adjustment Charge (REAC) CCT Revenue Increase	$16.09M	**0.48%**
Day-One Net Rate Impact	**$459.94M**	**13.62%**

If APS's proposed rates are adopted as requested by the Company, customers will experience a net base rate increase of $459.9 million—an overall average bill increase of 13.6%. The net increase and bill impact to customers is further discussed in the testimonies of Mr. Geisler and Ms. Hobbick. This additional revenue will provide APS an opportunity, not a guarantee, of earning a FVROR of 4.92% on a Fair Value Rate Base (FVRB) of $16.6 billion.

My Direct Testimony also describes the COSS used to support APS's rate design as well as the jurisdictional allocation of costs. In addition, I sponsor the additional COSS required by Decision No. 78317 (November 9, 2021).

Finally, my Direct Testimony explains the calculation used to determine the FVI derived from the Company's FVRB. The mechanics of the calculation are based on those adopted by the Commission in numerous decisions, including Decision

[2] Numbers in the figure have been rounded for ease of presentation.

Nos. 71448 (December 30, 2009), 73183 (May 24, 2012), 76295 (August 18, 2017), and 78317.

III. PROPOSED BASE FUEL AND PURCHASED POWER RATE

Q. IS APS PROPOSING ANY CHANGES TO TEST YEAR FUEL AND PURCHASED POWER EXPENSE?

A. Yes. I am sponsoring a pro forma that removes any deferrals of fuel expense included in the Test Year due to the operation of the PSA. This pro forma also removes the non-cash mark-to-market impacts. These non-cash accounting adjustments have no impact on the Company's actual Test Year fuel expense or anticipated future fuel expenses. These two adjustments result in an increase to Test Year expenses of $212.3 million and are shown in the Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals pro forma in SFR Schedule C-2, page 2, column 7.

Q. WHAT IS APS'S PROPOSAL FOR ITS BASE FUEL AND PURCHASED POWER RATE IN THIS PROCEEDING?

A. APS proposes to adjust its base fuel rate to better reflect its expected fuel and purchased power costs in the future. The Company's proposal increases the current base fuel and purchased power rate of 3.1451 ¢/kWh (as authorized by the Commission in Decision No. 78317) to 3.8321 ¢/kWh, an increase of 0.6870 ¢/kWh, with an equal and concurrent offset in PSA revenues at the time rates determined in this proceeding go into effect. APS witness Justin Joiner discusses APS fuel cost management efforts and fuel operations.

Q. HOW DID APS DETERMINE THE PROPOSED RATE?

A. The proposed fuel rate was determined by using the Test Year fuel rate as a baseline and using the 2023 fuel forecast discounted by 4% to remain near that Test Year baseline to minimize additional bill impact to customers. The 2023 forecasted fuel cost includes the removal of $15 million off-system sales mitigation for AG-X, which is described by Ms. Hobbick.

Q. HOW DOES THIS NEW BASE FUEL RATE AFFECT TEST YEAR EXPENSE?

A. Because the Test Year cost of fuel and purchased power expense actually incurred results in a Test Year fuel rate of 3.8281 ¢/kWh, the Base Fuel and Purchased Power Cost pro forma reflects an impact to Test Year operations of $1.2 million resulting in the proposed base fuel rate of 3.8321 ¢/kWh. The Base Fuel and Purchased Power pro forma calculations are provided in SFR Schedule C-2, page 2, column 6. Ms. Hobbick further describes the impact of APS's proposal to offset the increase in the base fuel and purchased power rate with a concurrent reduction in recovery through the PSA.

Q. WHAT CHANGE IN THE BASE RATES FOR PRODUCTION-RELATED CHEMICAL COSTS AND SALES OF EMISSIONS ALLOWANCES IS APS PROPOSING?

A. APS proposes that the current base production-related chemical cost of 0.05 ¢/kWh, authorized in Decision No. 78317, be increased to 0.0744 ¢/kWh. This rate reflects the $21.3 million actual cost of chemicals during the Test Year. The amount and costs of lime, ammonia, and sulfur associated with power plant emission controls varies with the amount of fuel burned at generating plants, and these costs were authorized for recovery through the PSA by the Commission in Decision No. 76295. Costs of these chemicals increased for many of the same reasons as fuel and purchased power prices are increasing, including inflationary impacts, raw material shortages, and supply chain issues, which are slowing the production of these chemicals. In addition, freight and other transportation costs have also increased. This proposal will increase the base cost of chemicals by approximately $7.1 million, with an equal and concurrent decrease in PSA revenues at the time rates determined in this proceeding go into effect. The impact of this adjustment is shown in the Chemical O&M pro forma in SFR Schedule C-2, page 3, column 8.

APS does not propose to change the current PSA base rate of ($0.000001) ¢/kWh for net margins from emission allowance sales.

IV. STANDARD FILING REQUIREMENT SCHEDULES (SFRS)

Q. PLEASE IDENTIFY THE SFRS THAT YOU ARE SPONSORING.

A. I am sponsoring SFR Schedule A-1, portions of SFR Schedules A-2, B-1, B-2, B-3, B-4a, C-1, C-2, F-1, and all G SFR Schedules.

The schedules themselves also contain numerous adjustments sponsored by other APS witnesses. I have attached an SFR index that lists the APS witnesses responsible for preparation of the various SFRs or elements of the SFRs (Attachment JRM-01DR).

Q. PLEASE DESCRIBE THE PORTIONS OF THE SFRS THAT YOU ARE SPONSORING.

A. SFR Schedule A-1 presents the requested overall increase in retail revenue requirements. SFR Schedule A-1 demonstrates that the adjusted Test Year rate of return for ACC jurisdictional operations was 1.43% on a FVRB of $16.6 billion. The rate of return on FVRB resulting from the requested increase of $772.3 million is 4.92%.

The Company's FVRB is a calculation based on the average of the Original Cost Rate Base (OCRB) and the Reconstruction Cost New less Depreciation (RCND) rate base. This calculation has been accepted historically by the Commission as an appropriate way of determining the FVRB. I show the FVRB in Attachment JRM-

07DR, which also offers a detailed calculation of the FVI discussed later in my testimony.

I sponsor portions of SFR Schedules B-1 and B-2, which provide the calculations of rate base for Total Company and ACC jurisdictional operations. The jurisdictional operations rate base calculations were developed through a COSS. I also sponsor the jurisdictional allocation portion of SFR Schedule B-4a, which shows the computation of adjusted jurisdictional RCND rate base as of June 30, 2022, using the same allocation factors as with OCRB.

Additionally, I sponsor portions of the C SFR Schedules that present the pro forma adjustments to the Test Year and the jurisdictional splits of the pro forma adjustments between Total Company and ACC jurisdictional operations. The sponsorship of the individual pro forma adjustments is noted on SFR Schedule C-2.

The G SFR Schedules provide detailed information regarding the Company's COSS. These schedules address existing and expected percentages of COS and rates of return by sub-class, show pro forma adjusted amounts of OCRB and operating expenses allocated to ACC jurisdictional customers, and list the allocation factors used in preparing the study.

- SFR Schedule G-1 shows percentages of the COS and the original cost rate of return at existing rates by customer class, based on the adjusted Test Year COSS.
- SFR Schedule G-2 is similar to SFR Schedule G-1, except it reflects percentages of the COS and returns by customer class that would result under APS's proposed rates.

- SFR Schedule G-3 shows the functionalized dollar amount and percentage of adjusted rate base allocated to each retail customer class.
- SFR Schedule G-4 shows the functionalized amount of operating expenses allocated to each retail customer class.
- SFR Schedule G-5 shows the amount of functionalized adjusted rate base allocated to ACC jurisdictional customers.
- SFR Schedule G-6 shows the amount of functionalized adjusted operating expenses allocated to ACC jurisdictional customers.
- SFR Schedule G-7 lists the allocation factors used in preparing the Test Year COSS.

Q. DO YOU SPONSOR ANY OTHER DOCUMENTS RELATED TO CLASS COST OF SERVICE?

A. Yes. Attachments JRM-02DR (site load COSS residential broken out), JRM-03DR (site load residential combined) and JRM-04DR (delivered load COSS residential broken out) to my testimony are summaries showing:

1. The jurisdictional separation of rate base costs, revenues, and operating expenses between ACC and all other jurisdictions;
2. The further allocation by retail customer class of total ACC allocated costs and the percentage of cost to serve paid by each major customer class;
3. The same information as described in (2) above for each general service sub-class; and,
4. The same information as described in (2) above for each residential service sub-class, including the solar energy and demand rate sub-classes where applicable.

V. COST OF SERVICE STUDY (COSS)

Q. PLEASE DESCRIBE A COSS GENERALLY.

A. A COSS is a detailed assessment of utility costs and revenues that supports a requested rate increase, both in total and for separate rate classes. The study compiles and evaluates the utility's costs for the Test Year period and makes certain normalizing pro forma adjustments to reflect an appropriate test of the adequacy of the utility's rates. The COSS separates the cost and revenue information to reflect those that are jurisdictional to the Commission. Lastly, the study allocates the costs and revenues to various customer rate classes based on cost drivers or cost causation principles. This allocation sets the cost responsibility and revenue deficiency for each class.

Q. WHAT IS THE TEST YEAR FOR APS'S COSS IN THIS RATE CASE?

A. APS conducted an embedded COSS using data from the 12-month period ending June 30, 2022, as the test period. An embedded COSS takes the total revenue requirement and allocates it among customer classes.

Q. PLEASE DISCUSS THE DEVELOPMENT OF THE COSS.

A. This study was prepared using accepted methods of functionalization, classification, and allocation.

Q. WHAT IS FUNCTIONALIZATION?

A. **Functionalization** is the process of attributing each rate base or expense item to a particular function—namely production (generation of electricity), transmission, distribution, or customer service (*e.g.*, metering and billing)—in the provision of electric service. An example of functionalization is assigning the costs of building and operating the Company's generation power plants to the production function.

Q. WHAT IS CLASSIFICATION?

A. **Classification** is the process of determining the factor or factors that drive the magnitude of the cost. For example:

- If a cost to serve is driven by the amount of kWh energy consumed, such as fuel cost, it is classified as energy.
- If a cost is driven by the rate at which energy is consumed, or kW capacity, it is classified as demand.
- If a cost is driven by the number of customers taking service on the APS system, irrespective of either the kW demand or kWh energy, it is classified as customer.

Q. WHAT IS ALLOCATION?

A. **Allocation** occurs after a cost has been functionalized and classified. Allocation factors—such as class coincident peak (CP) demand contribution at the time of system peak, non-coincident class peak (NCP), the sum of individual peaks, energy, or number of customers—are applied to allocate costs to other jurisdictions, customer classes and sub-classes, and rate schedules. A simple example is the allocation of energy-related costs by kWh consumption to different customer classes.

In summary, in the COSS, the total expense and rate base items that comprise APS's costs are grouped into major categories, such as Plant in Service or Operating and Maintenance (O&M) expense. Each category is first functionalized into production, transmission, distribution, or customer-related costs, then classified as demand, energy, or customer-related. Allocation factors based on kW, kWh, and number of customers are then developed so that the functionalized and classified costs may be allocated to the ACC retail jurisdiction and to the various retail customer classes and sub-classes.

Q. HOW DID YOU ALLOCATE FUNCTIONALIZED COSTS BETWEEN JURISDICTIONS AND AMONG CUSTOMER CLASSES?

A. Production-related assets are generally designed and built to enable the Company to meet its system peak load. Therefore, the costs associated with these investments are allocated between jurisdictions based on the average of the system peak demands occurring in the months of June, July, August, and September (collectively referred to as 4-CP, with the months being core summer months) to determine jurisdictional cost responsibility. This is consistent with the allocation method that APS is required to use in its rate cases before the Federal Energy Regulatory Commission (FERC) and creates jurisdictional alignment to ensure the right proportion of cost is being allocated to each jurisdiction. It also eliminates the potential that costs are not recovered from either jurisdiction due to differences in allocation methods. It has been accepted as the jurisdictional allocation methodology by the Commission for many years.

Within the ACC jurisdictional customer classes, production costs were allocated based on the Average and Peak Demand (A&P) method. This method was adopted by the Commission in Decision No. 78317. The A&P method uses the sum of an energy, or average demand, allocator as well as a peak demand allocator:

1. **Energy (Average Demand) allocator** – each class's Test Year energy usage divided by 8,760 hours to calculate average energy demand.
2. **Peak Demand allocator** – the average of the customers' 4-CP during the months of June, July, August, and September.

In addition, APS analyzed the AG-X customer group as a separate customer class in the allocating of generation-related costs.

Transmission plant was directly assigned to the non-ACC jurisdictional portion of the COSS. However, a portion of transmission costs are brought back into the ACC jurisdictional cost of service to offset the existing Open Access Transmission Tariff (OATT) revenues from jurisdictional customers. Such an offset ensures that there is no double-counting of transmission costs between the ACC and non-ACC jurisdictions, and effectively assumes that each customer class pays the cost of transmission service.[3]

Distribution plant, unlike production and transmission plant, is generally designed to meet a customer class's peak load, which may or may not coincide with the system peak load. Thus, costs related to distribution substations and primary distribution lines are typically allocated based on NCP loads. However, a portion of these costs are allocated on a customer basis.[4] Allocation of costs related to distribution transformers and secondary distribution lines are based on the summation of the individual peak loads or demands of all customers within a particular customer class (Sum of Individual Max). Each of these allocation methods has been used by APS and accepted by the Commission for many years.

Q. PLEASE EXPLAIN THE USE OF REVENUE CREDITS IN THE COSS.

A. APS sells electric service to parties that are not traditional APS retail customers, such as sales to rate schedule E-36 XL customers for station service power to large generation plants owned by others. These transactions produce net benefits because their rates more than cover their incremental costs. Therefore, these revenues are allocated, or credited, to all customer classes. In other words, the entire margin that

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[3] The one exception for transmission costs is residential rooftop solar customers. To address the mismatch between what solar and non-solar residential customers pay for the transmission portion of their bills, APS reallocated the direct assigned cost responsibility to residential customers using each residential sub-class's 4-CP.

[4] *See* Decision No. 78317 at 241, lines 2-6.

APS realizes from these non-retail transactions is attributed to each class through the revenue credit, benefiting all customers by lowering the amount of their overall revenue requirements.

APS also treats non-firm, short-term transactions, and other small items, such as rent from electric property, forfeited discounts, miscellaneous service revenues, and other electric revenues, as revenue credits.

Q. ARE THERE ANY COST ELEMENTS THAT RECEIVE RECOVERY TREATMENT OUTSIDE OF THE BASE RATE SCHEDULES DEVELOPED BY THE COSS?

A. The COSS only addresses the base rate portion of the cost to serve. Additional revenues and expenses from adjustors are removed from the COSS to get a base rate revenue requirement. Various adjustors, surcharges, regulatory assessments, sales/transaction privilege taxes, and franchise fees are charged outside of base rates.

Q. DID YOU REVISE APS'S COSS METHODOLOGY TO COMPLY WITH THE MOST RECENT RATE CASE DECISION?

A. Yes. APS made the following changes to its cost allocation process as required in Decision No. 78317:

- The production demand costs (power plants) were allocated using the Average and Peak (A&P) method specified by the Commission.[5]
- The primary distribution costs in FERC Accounts 360, 361, and 364 through 368 were allocated as both demand-related and customer-related with relevant allocators.[6]

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[5] *Id.* at 234.
[6] *Id.* at 241.

- Three separate COS studies were performed for residential solar classes: one using site load, another using delivered load, and a third combining solar customers with non-solar customers within their general rate class.[7]

In these three studies, the allocation of primary distribution costs for solar and non-solar classes used the load coincident with the time of the total residential NCP (combining both solar and non-solar customers).[8]

Also in these three studies, the meter costs included the actual bi-directional meter cost from the end of the Test Year but excluded the cost of separate production meters.[9]

VI. ALLOCATION OF PRODUCTION CAPACITY COSTS

Q. WHAT IS THE DIFFERENCE BETWEEN THE AVERAGE AND EXCESS DEMAND (A&E) AND A&P ALLOCATION METHODS?

A. The A&P method calculates two components: (1) each class's share of annual energy (or average demand) and (2) each class's share of peak demand. These two components are then combined with a simple average or some type of weighted average calculation. The A&E method also calculates two components: (1) each class's share of average demand and (2) each class's share of the peak demand component that exceeds average demand. It is the formulation of the second component that separates the two methods.

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[7] *Id.* at 255, lines 19-23.
[8] *Id.* at 255, lines 27-28.
[9] *Id.* at 255, lines 24-26.

Q. WHAT DID THE COMMISSION CONCLUDE IN DECISION NO. 78317 CONCERNING THE COST DRIVER FOR APS'S PRODUCTION DEMAND COSTS?

A. The Commission concluded that "APS is a summer-peaking utility, and a large portion of its production costs are attributable to peak demand. Accordingly, an equitable method of allocating production costs will recognize causation of the peak demand."[10]

Q. DOES THE ADOPTED A&P METHOD ATTRIBUTE A "LARGE PORTION" OF PRODUCTION COSTS TO PEAK DEMAND?

A. No, it does not. In fact, it allocates fewer of such costs to system peaks than either 4-CP or A&E.

Q. PLEASE EXPLAIN.

A. The A&P method attributes a large portion of production demand costs to annual energy usage and only a smaller, secondary portion to summer peak demand. In other words, the A&P method rests on the assumption that a large portion of power plant capacity costs are driven by customers' energy usage, 24 hours a day, 7 days a week, in both summer and winter seasons. This is just not the case, especially for APS's service territory.

In addition, the A&P method makes matters worse by double weighting the energy component. This occurs because the A&P method combines an annual energy component, which is the same thing as average demand, with a peak demand component. The double weighting of energy occurs because the second component (i.e., the peak demand) includes each class's share of the entire peak demand (i.e., both the average demand portion and the remaining amount). In short, the average

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[10] *Id.* at 234, lines 12-14.

demand component is factored into both the energy and peak portions of the allocator, and thus counted twice.

Q. DOES THE A&E METHOD HAVE THE ISSUE OF DOUBLE WEIGHTING THE ENERGY COMPONENT?

A. No. The A&E method uses (1) average demand (energy) and (2) the portion of peak demand that is above or more than the average demand, and not the entire peak, as is used in the A&P method. Because the second component of the A&E method only uses each class's contribution to excess peak demand, it does not suffer from the same double counting flaw as the A&P method.

Q. DOES THE SPECIFIC A&P METHOD REQUIRED BY THE COMMISSION FURTHER OVEREMPHASIZE THE ENERGY COMPONENT?

A. Yes. The A&P method adopted by the Commission further compounds the flaw in the model by using a particular weighted average calculation to combine the energy and peak components, which places even more emphasis on the energy component. This method not only doubles the energy component of the allocator, but then places additional weight on the energy component when the two components (energy and peak) are combined.

Q. DOES APS SUPPORT USING THE A&P METHOD TO ALLOCATE PRODUCTION COSTS AS WAS ORDERED IN APS'S LAST RATE CASE DECISION?

A. No. As discussed above, the A&P method places too high of an emphasis on annual energy as a cost driver for production capacity, as opposed to summer peak demand. As long as summer peak demand is a key driver for production capacity costs in Arizona, the A&P method is not the best way to reflect this cost driver.

Q. HOW DO OTHER JURISDICTIONS ALLOCATE PRODUCTION DEMAND COSTS?

A. Generally, I am aware that many utilities use the 4-CP method or a similar method to allocate production demand costs because it recognizes that the primary driver for these costs is the system peak demand.

In addition, if an allocator is used that combines both peak demand and energy, the A&E method is preferred by most jurisdictions given the double counting flaw in the A&P method discussed above. The A&P method is rarely adopted in other jurisdictions for electric utilities.

Q. WHAT DOES APS RECOMMEND CONCERNING THE ALLOCATION METHOD FOR PRODUCTION CAPACITY COSTS?

A. APS requests, given the issues discussed previously and highlighted below, that the Commission re-examine its preferred method to allocate production demand costs and adopt the A&E and/or 4-CP methods rather than the A&P method.

- The 4-CP method is more consistent with the recognition that a large portion of production demand costs are caused by the summer peak. It allocates these costs based on each class's load, coincident with the system peak, in June, July, August, and September.
- The A&E method accurately reflects the costs for the residential class because the CP and NCP information used in this method is very consistent.
- The traditional A&E method will likely overstate the costs for classes with low load factors where the NCP differs materially from the CP, such as schools and churches. However, these are relatively small sub-classes of the general service class and this deficiency in the A&E method for these sub-classes could be resolved by using 4-CP in place of NCP.

VII. SOLAR COST OF SERVICE STUDY

Q. WHAT IS THE PURPOSE OF A SOLAR COSS?

A. The adoption of residential rooftop solar systems has grown significantly over the last ten years. In addition, these systems are designed to last 20 years or more. This class of customers is substantial and growing. These customers have unique energy usage and on-site generation, with related impacts on the cost to serve them and important ramifications for recovery of their cost of service in rates.

The Commission held hearings on the Cost and Value of Solar (CVS) to explore and address these issues. One key question was whether residential solar customers were paying a fair share of their cost of service in rates, or whether these costs were being under-recovered shifting recovery to non-solar customers.

The Commission, among other things, ultimately determined that residential customers with solar were partial requirements customers and the question of whether solar customers are paying their fair share of their cost of service would be best answered in a solar COSS in a rate case. Thus, the purpose of the solar COSS is to determine whether solar customers are paying rates that appropriately cover their costs.

Q. DID APS PERFORM A SOLAR COST OF SERVICE STUDY IN THIS CASE?

A. Yes. As ordered by the Commission in Decision No. 78317, APS performed a COSS for the residential solar class using two approaches—a top-down approach and a bottom-up approach. In the last two rate cases, APS presented the solar COSS using only the top-down approach.

Q. PLEASE EXPLAIN THESE APPROACHES.

A. Both approaches compare the utility costs incurred for the solar class with the actual revenues collected. If the annual revenues from rates are less than the costs incurred, then the solar class is underpaying for its cost of service, and vice-versa.

The first approach, the top-down approach, calculates the cost of service for the site load and then evaluates cost credits for the self-supply.[11] This allocates grid and power plant costs according to the total consumption in the home—not just the load metered by the utility. Next, the savings in the utility's grid and power plant costs that occur because of the solar generation self-supply are estimated and credited back against the site load cost of service. Finally, the net value of the solar generation that is exported to the grid is calculated by comparing the fuel cost savings that the utility incurs to the price the utility pays for this power, either through the net metering program or the Resource Comparison Proxy (RCP) program. The top-down approach calculates the net impact on utility costs from a solar customer, which is the cost responsibility that should be recovered in rates.

The second approach, the bottom-up approach, calculates the cost of service based on the delivered load (i.e., the load supplied by the utility) and then adds additional utility costs that are being incurred on behalf of the solar customer, based on the self-supply load information. These additional costs include such things as standby and back-up capacity costs for power plants and the grid, upon which the solar customer continues to rely, and secondary service costs that are not eliminated or reduced when a customer adds solar generation to its home. This approach also calculates the net value (or cost) of the solar export power.

[11] Part of the solar generation in any instant directly serves the load in the home, which is referred to as "self-supply" and the remaining excess portion is exported to the grid.

Q. WHY NOT BASE THE COSS SOLELY ON THE DELIVERED LOAD, LIKE OTHER CUSTOMER CLASSES?

A. Because doing so would significantly understate the costs that the utility incurs to serve the solar customer. As discussed above, the solar customer has partial requirements service where only a portion of their load is generally served by the utility and a portion by the on-site generator or self-supply. Both portions require support and costs from the utility because the customer is still hooked up to the grid and relies on the utility to back-up their solar generator and to provide the service needed for the home. A COSS based solely on the delivered load portion would ignore the costs for the self-supply portion.

VIII. <u>SOLAR COSS – TOP-DOWN APPROACH (SITE LOAD)</u>

Q. PLEASE DESCRIBE THE TOP-DOWN APPROACH TO SOLAR COSS.

A. As mentioned above, the top-down approach to a solar COSS first evaluates the cost of service based on the site load, which is the total consumption in the home, and then credits back the utility cost savings from the solar generation. APS used this approach in each of its last two rate cases. A summary review of the top-down approach and corresponding results are discussed below.

Q. HOW WERE THE SITE LOAD COSTS DETERMINED?

A. The hourly site load for the Test Year was developed by adding the hourly delivered load and the portion of the hourly solar generation that was used for self-supply. The resulting site load reflects the total consumption in the home. The cost of utility service was then determined for the site load based on the standard cost-of-service allocation methods used for the other customer classes, as described above.

Q. HOW WERE THE SOLAR CREDITS DERIVED?

A. The utility cost of service savings from the solar generation, which were credited against the site load cost of service, were derived by computing the percentage difference between the relevant credit factor for the site load versus the delivered load. This percentage difference was then applied to the site load gross revenue requirement. The credit factors for each cost type are as follows:

- Production Demand Credit – based on 4-CP and summer average NCP
- Transmission Credit – based on 4-CP
- Distribution Substation Credit – based on summer average NCP
- Distribution Primary Credit – based on summer average NCP
- Distribution Secondary Credit – based on average sum of individual max peaks for the summer months

Q. HOW WAS THE NET VALUE OF THE SOLAR EXPORT POWER DETERMINED?

A. The solar export power reduces the overall cost of fuel for the utility, which was valued at the new base fuel cost proposed in this rate case. This fuel cost reduction was then netted against the price paid to the solar customers for this export energy, either through the net metering or RCP programs.

Q. WHAT WERE THE RESULTS OF THE TOP-DOWN SOLAR COSS?

A. The results of the top-down solar COSS are provided in Attachment JRM-05DR and a summary of the results are shown in Figure 2.

Figure 2. Solar Cost of Service

(Top-Down Approach)

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
% COS Recovered	**37.7%**	**68.0%**	**50.4%**	**56.2%**

IX. SOLAR COSS – BOTTOM-UP APPROACH (DELIVERED LOAD)

Q. PLEASE DESCRIBE THE BOTTOM-UP APPROACH TO SOLAR COSS.

A. As discussed above, the bottom-up approach calculates the COSS based on the delivered load for the solar class and then assesses the additional costs for services upon which solar customers continue to rely on, and for which the utility incurs costs, in addition to the costs associated with the delivered load. The net value of the export power is also assessed. As a first step, the cost allocation for delivered load for the solar class follows the general retail allocation process described above.

Q. WHAT ARE THE ADDITIONAL COSTS TO SERVE SOLAR CUSTOMERS NOT REFELCTED BY DELIVERED LOAD?

A. The additional costs to serve solar customers, beyond those captured in the delivered load, include:

- The back-up costs for production capacity needed to "firm up" the solar generation to provide reliable service to the solar customer at issue;
- The reserve margin for generation;
- The generation services that the solar customer relies upon, but which cannot be supplied from solar generation. These services would include items such as ramping, integration costs, and in-rush current supply;
- The primary grid costs that the solar customer continues to rely on and benefit from as they remain connected to the grid;

- The primary grid costs that are used by the solar customer to export power to the grid; and
- The secondary grid costs that are sized to serve the connected load of the house and are not reduced when the customer adds solar generation.

Q. PLEASE EXPLAIN THE BACK-UP PRODUCTION CAPACITY COSTS FOR SOLAR CUSTOMERS.

A. One of the key findings of the CVS hearing was that rooftop solar customers are partial requirements customers. This means that the customer receives some of its production capacity and production energy needs from its generator and the remaining amount from the utility. Partial requirements customers necessarily rely on the utility to provide back-up power, or production capacity, to serve their entire load if the generator is not available, either through an equipment outage or removal, or in the case of solar, other factors such as cloud cover or darkness. This back-up power must include a reserve margin, consistent with system power plant requirements.

Q. WHAT ARE APS'S PARTIAL REQUIREMENTS RATES?

A. APS currently has partial requirement rate rider schedules EPR-2, EPR-6 Legacy (frozen), EPR-6 (not frozen), RCP, E-56 R and E-56 for customers with on-site generation. EPR-2 applies to on-site generators less than or equal to 100 kW-ac in size. EPR-6 Legacy and RCP apply specifically to residential solar generation. For business customers, EPR-6 applies to the net metering program, and E-56 R and E-56 apply to renewable and non-renewable generation, respectively, for generators greater than 100 kW in size.

Q. ARE CUSTOMERS SPECIFICALLY CHARGED FOR BACK-UP POWER UNDER THESE RATES?

A. The rates for larger generators (>100 kW) typically have specific charges for back-up power services, while the rates for smaller generators (<=100 kW) typically do not expressly charge the residential solar customers for back-up services.[12]

Q. DOES THIS MEAN THAT SMALLER SOLAR GENERATORS DO NOT REQUIRE APS TO BACK UP THEIR SYSTEMS?

A. No. Back-up power service and costs still exist, even though APS does not specifically charge the individual customer a back-up fee for it. The fact that there is no charge for back-up service for these smaller solar customers means that the related costs are paid for by all non-solar customers in general rates. The result is also a revenue deficiency for the solar classes in the COSS, a key reason for performing a COSS specific to the residential solar classes.

Q. WHAT FACTORS ARE IMPORTANT WHEN CONSIDERING THE APPROPRIATE COST FOR BACK-UP PRODUCTION CAPACITY SERVICE FOR RESIDENTIAL SOLAR CUSTOMERS?

A. The amount of back-up production capacity service a solar customer needs depends on several factors, including: (1) the availability of the solar generator to serve the customer's load throughout the year, especially during critical high load hours or system emergencies; (2) the physical dependability of the generator; and (3) the customer's obligation (contractual or otherwise) to operate the generator and serve an expected portion of their load. These combined factors are often expressed with terms such as "firmness," "resource adequacy," "capacity value," "reliability," "effective load carrying capability" and others, each of which has its own definition and purpose. However, the core issue is the amount of solar generation capacity

[12] Some residential legacy solar customers served under the EPR-6 Legacy rate pay an LFCR DG charge. This charge has been frozen since September 1, 2017.

that can be dependably relied on to serve the customer's load during critical peak hours.

Q. DO APS'S PARTIAL REQUIREMENTS RATES INCLUDE A DEFINITION OF "FIRMNESS"?

A. Yes. APS's partial requirement rate schedules and riders include definitions of firm and non-firm power, which provide some guidance on this issue. The "firm power" definition assesses whether the power is available to the utility when needed, and evaluates the expected or demonstrated reliability of the supply compared with the reliability of the utility's generation. "Non-firm power," on the other hand, is defined as power supplied "at the customer's option," where no firm guarantee is provided, and the power can be interrupted by the customer at any time. These definitions are generally consistent with the factors discussed above in terms of availability, dependability, and the customer's obligation to supply the power. Examples of these definitions (as shown in Partial Requirements Rate Rider EPR 2) are provided below:

> *Non-Firm Power is electric power which is supplied by the Customer's generator at the Customer's option, where no firm guarantee is provided and the power can be interrupted by the Customer at any time.*
>
> *Firm Power is power available, upon demand, at all times (except for forced outages) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.*

Q. PLEASE EXPLAIN THE PROBLEM CONCERNING THE AVAILABILITY OF SOLAR GENERATION TO SERVE THE RESIDENTIAL LOAD DURING SUMMER PEAK HOURS.

A. A key issue for assessing the firmness of on-site solar generation is its availability to serve the customer's load, especially during critical peak hours, which typically occur in the late afternoon and early evening hours in the summer.

Figure 3 shows the residential class loads during the summer, along with the availability of the solar generation for the critical peak hours of 3 p.m. to 8 p.m., where the load is typically 91% or more of the peak hour. The third column reflects the information for the hour 5 p.m. to 6 p.m., which is typically both the coincident system peak hour (CP) and the residential class peak hour (NCP). Figure 3 also provides the information from four assessment points: the average of the four summer monthly CP days (4-CP), the average of the four summer monthly residential class peak days (4-NCP), the average of all core summer days that are at least 90% of the class peak, and the average over all core summer days. These four assessment points provide a very robust look at this issue.

Notice that the residential load remains very high and consistent throughout the entire 3 p.m. to 8 p.m. critical peak period. For example, looking at the 4-CP data, the residential load was 4,043 MW in the 5 p.m. to 6 p.m. system peak hour. It remained almost as high at 3,980 MW at hour 6 p.m. to 7 p.m., which is 98% of the peak hourly value, or a mere 2% drop off. Similarly, in the hour 7 p.m. to 8 p.m., the load continued to remain very high at 3,756 MW, which is 93% of the peak hourly value, only a 7% drop off.

Contrast the foregoing with the availability of the solar generation during the same hours. Again, looking at the 4-CP information, the solar generation was already dropping to 207 MW at the 5 p.m. to 6 p.m. peak hour from 373 MW in the prior hour. An additional significant drop to 69 MW followed in the hour 6 p.m. to 7 p.m., which is a 67% drop off from the peak hour; and at 7 p.m. to 8 p.m., when loads have only declined by 7% from the peak value, solar generation dropped to a mere 6 MW, which is a 97% drop off from the peak hour.

Further, this pattern of solar generation and the significant decline in output across the critical peak hours in the summer, when loads are at their highest, is consistent across each of the four points of assessment. For example, the solar generation drop off in hour 6 p.m. to 7 p.m. ranges from 65% to 69% across the four points of assessment. Likewise, the drop off in hour 7 p.m. to 8 p.m. ranges from 97% to 98%.

Figure 3. Residential Class Load and Solar Generation

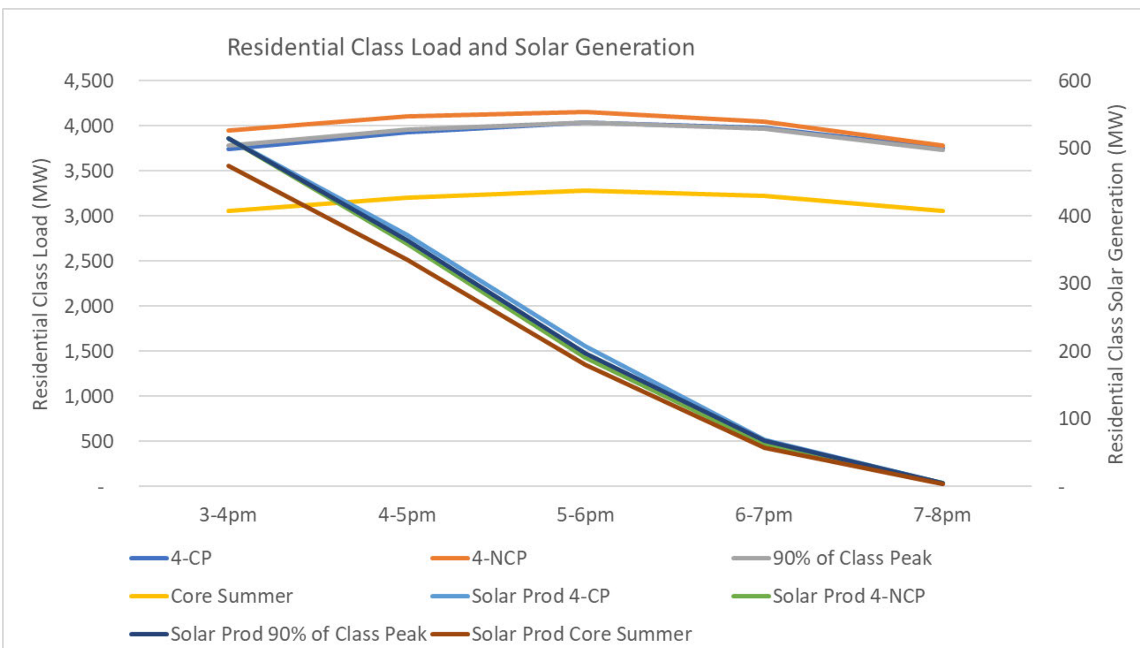
June-September Test Year, Hours 3 p.m. to 8 p.m., MW

	Peak Hour				
	3-4 pm	4-5 pm	5-6 pm	6-7 pm	7-8 pm
Residential Class Load					
4-CP days	3,745	3,929	4,043	3,980	3,756
class peak 4-NCP days	3,951	4,109	4,159	4,052	3,785
All days >= 90% of class peak	3,788	3,956	4,041	3,966	3,737
All core summer days	3,060	3,202	3,288	3,225	3,057
Residential Solar Generation					
4-CP days	514	373	207	69	6
class peak 4-NCP days	516	360	191	62	5
All days >= 90% of class peak	515	364	197	67	5
All core summer days	474	335	180	57	4

Q. WHAT IS YOUR CONCLUSION CONCERNING THE AVAILABILITY OF RESIDENTIAL SOLAR POWER?

A. As shown in Figure 4 below, residential loads are high across the entire 3 p.m. to 8 p.m. critical peak hours in the core summer months, but solar generation declines significantly over these same hours, it is evident that the generator does not have sufficient availability to provide the necessary production capacity to serve the home. It has a strong availability in hours 3 p.m. to 4 p.m. and 4 p.m. to 5 p.m., but declining availability at the 5 p.m. to 6 p.m. system peak hour, more significantly reduced availability at 6 p.m. to 7 p.m., and almost no availability at 7 p.m. to 8 p.m. As a result, the residential solar customer will require significant back-up power (or production capacity) from APS to reliably serve the home's load during summer critical peak hours.

Figure 4. Residential Class Load and Solar Generation



Q. IS THE COST FOR THE BACK-UP POWER ALREADY CAPTURED IN THE COSS FOR THE DELIVERED LOAD?

A. Only partially. Using the A&P cost allocation method, the production capacity cost for the delivered load (the portion of the home's consumption that is supplied by APS) is based on the solar customers' 4-CP delivered demand and the annual energy supplied by APS. The 4-CP delivered demand would be inversely related to the solar generation provided in Figure 4. As solar generation declines, delivered load increases for a given level of total demand (or site load) in the home. Because the 4-CP delivered demand is based on the load at 5 p.m. to 6 p.m., it already captures the solar generation drop off from 4 p.m. to 5 p.m. Therefore, that drop off will be excluded from any assessment of back-up power costs.

Conversely, the subsequent and further decline in solar generation in the hours 6 p.m. to 7 p.m. and 7 p.m. to 8 p.m., and the concomitant increase in the delivered demand, is not reflected in the allocated costs, because the "peak" part of the A&P method is only based on the delivered load at hour 5 p.m. to 6 p.m. The increased critical peak load resulting from the solar generation drop off from 6 p.m. to 8 p.m., which must be served by APS, is not captured in the A&P calculation. Technically, the "average" part of the A&P method would capture a very small part of this cost because the annual energy for the delivered load would also increase from the additional load at 6 p.m. to 8 p.m. However, this impact would be de minimis because this increase of energy during a few critical peak hours would represent only a very small percentage of the customer's total annual consumption of delivered energy.

Q. HOW DID APS ASSESS THE DEPENDABILITY FACTOR OF RESIDENTIAL SOLAR GENERATION?

A. I am using the term "dependability" to generically refer to the performance of the solar generator: it may have limited availability to serve load in certain peak hours, but when it is supposed to be available, how well does it actually run? To assess this factor, I considered several issues.

First, residential solar is comprised of a portfolio of thousands of individual generators, which enhances overall dependability. If one generator is experiencing an outage during a critical peak hour, it would only represent a very small portion of total solar generation supply. In addition, residential solar is located on the distribution grid and, therefore, not susceptible to any interruptions, cuts, or congestion issues on the transmission grid enhancing its dependability.

Next, solar customers have a strong incentive to keep their systems running as much as possible, especially those that are paying off a solar lease or loan. In fact, some leases may include a maintenance contract. Such an incentive also enhances dependability.

Conversely, the primary issue that would negatively impact the dependability of residential solar is the weather factor. There is a risk that cloud cover could significantly reduce the solar generation and this could potentially occur during critical peak hours. Furthermore, the cloud cover could impact many generators at the same time, thus reducing the ability to diversify the outage over the thousands of generators.

To assess this issue, I looked at the total solar generation for the core summer months and identified days when the output dropped significantly during the peak hours. This is not assessing the generation drop off across the peak hours in a day, which is the availability issue. Rather, it reflects the drop off in generation in similar hours across different days. I also reviewed the variability, or standard deviation, of the solar generation for each peak hour across the various core summer days. The standard deviation of the generation within each critical hour reflects the range of generation that can be depended on to serve load and the associated dependability or riskiness of the generation. The higher the standard deviation, the lower the dependability.

Q. WHAT WERE THE RESULTS OF YOUR ASSESSMENT OF THE VARIABILITY OF TOTAL SOLAR GENERATION?

A. The results for the lowest solar generation days are shown in Figure 5. As shown, there were a number of summer days where the solar generation dropped off significantly in the 3 p.m. to 8 p.m. hours. For example, on day 8/31, the total residential solar generation dropped to 24 MW in hour 5 p.m. to 6 p.m. from an average amount for core summer days of 180 MW for the same hour. The solar generation at 5 p.m. to 6 p.m. for all the days on Figure 5 ranges from 24 MW to 95 MW, each of which is a significant decline from the core summer average. The residential class load at 5 p.m. to 6 p.m. for the corresponding days is also provided in Figure 5. As shown, some of the days with low solar generation also had relatively lower residential loads (e.g., days 7/23, 9/26, 9/27, and 9/29). However, there were a couple days with low solar generation where the residential loads were comparatively high. These days include 7/11 and 7/21. The latter are the concerning days for the determination of the dependability of solar generation.

Figure 5. Residential Solar Generation, Lowest Days

June-September Test Year MW

	Solar Generation			**Residential Load**
Date	3-4 (pm)	4-5 (pm)	**5-6 (pm)**	5-6 (pm)
8/31	156	65	24	2,185
7/23	75	55	40	1,616
9/26	122	109	44	1,585
9/29	270	146	45	1,828
9/23	353	201	48	2,724
9/27	270	165	66	1,863
9/24	380	215	69	2,164
9/28	359	214	70	2,122
9/30	421	250	76	2,020
9/18	233	138	78	2,485
7/11	**462**	**237**	**88**	**4,008**
9/17	329	223	89	2,809
9/25	438	271	94	2,598
7/21	**407**	**207**	**95**	**3,534**

The standard deviation information is provided in Figure 6. This figure shows the variability of the solar generation across the summer days for each of the critical peak hours. This statistic indicates how disperse the solar output values were over all the summer days. A higher standard deviation indicates a higher range of expected solar output in the hour and the lower the dependability of the solar generation.

If solar generation is normally distributed, then approximately 68% of the daily values for any given hour will lie within (+/-) one standard deviation unit of the mean, and about 95% will lie within two standard deviation units of the mean.[13] For example, as shown, the standard deviation of solar generation in the 5 p.m. to 6 p.m. peak hour for core summer days is 62 MW, while the average generation for the same hour is 180 MW (from Figure 6). This means that 68% of the daily values will fall in the range of 118 to 242 MW (180 +/- 62) and about 95% of the values will fall in the range of 56 to 304 MW (180 +/- 2 X 62). Thus, if you were trying to predict the total solar generation that could be depended on, during a summer day at the 5 p.m. to 6 p.m. peak hour, the average amount of 180 MW would be a good estimate. However, the actual amount could vary significantly from day to day. In fact, the range of possible values that would contain the right answer, 95% of the time, would be 56 to 304 MW, a significant spread.[14]

Q. ARE THERE ANY OTHER POINTS OF INTEREST YOU WOULD LIKE TO MAKE?

A. As shown on Figure 6, the standard deviation computed over the top 10% load days is lower than the standard deviation for all summer days. For example, the standard deviation over the top 10% load days for hour 5 p.m. to 6 p.m. is 41 MW compared to the 62 MW for all summer days.

[13] The precise number is 1.96 standard deviation units for a 95% confidence interval.
[14] Specifically, this means that in repeated samples or experiments the range will contain the true value of the mean in 95% of those experiments.

Figure 6. Residential Solar Generation

Mean and Standard Deviation

June-September Test Year MW

Hour (pm)	3-4	4-5	**5-6**	6-7	7-8
Mean (summer days)	474	335	180	57	4
Standard Deviation	102	85	62	35	4
Mean (top 10% days)	514	367	201	68	5
Standard Deviation	38	45	41	27	4

Q. WHAT DO YOU CONCLUDE ABOUT THE DEPENDABILITY AND RELIABILITY OF RESIDENTIAL SOLAR GENERATION?

A. The dependability is a mix: there is a large portfolio of thousands of solar generators, which diversifies and lessens the impact of any single generator outage; there is a high incentive for customers to keep the generators running as much as possible; and the solar generators are located on the distribution grid and therefore not susceptible to transmission related interruptions. Each of these factors increase dependability.

On the other hand, the actual output has a variability across different summer days in the peak hours that is not insignificant, which lessens dependability. On the plus side, this variability is lower for the top load days in the summer. Finally, the solar generation is susceptible to weather related interruptions that could impact many generators at the same time. Such interruptions were observed in a number of days in the core summer months in the Test Year. While many of these general interruptions occurred on particular summer days when the residential load was not that high, some occurred during relatively high load days.

Q. PLEASE DESCRIBE THE LAST FACTOR FOR FIRMNESS, THE CUSTOMER'S OBLIGATION TO SUPPLY POWER.

A. The final concept for assessing the firmness of solar power is the level of obligation on the customer to provide the power, the guaranteed delivery of the power by the customer, or the level of customer optionality to provide the power. The definitions of firm and non-firm power in APS's partial requirements rates include terms such as "available upon demand" by the utility, "firm guarantee," and "customer's option." In determining the firmness of the solar power for a COSS, the solar customer has a strong incentive to run their generator as much as possible. Nevertheless, the complete lack of any delivery requirements or restrictions to customer optionality does have a negative impact, albeit a relatively modest one, on the dependability.

Q. WHAT IS YOUR OVERALL CONCLUSION ON THE FIRMNESS OF RESIDENTIAL SOLAR POWER?

A. Considering the three factors and the data and concepts presented, residential solar generation has a significant reduction in firmness for the limited availability over the summer peak hours; has a medium reduction in firmness for the dependability issue; and a modest reduction in firmness for the customer optionality issue. So, if you start with 100% firm power, the reduction for limited availability would be in the 30% to 50% range, the reduction for dependability would be 10% to 20%, and the reduction for customer optionality would be 10%. Overall, the reduction in firmness would be in the range of 50% to 80%. Stated the other way, the firmness or capacity value of residential solar generation during summer peak load hours would be in the range of 20% to 50%. For the solar COSS, we used the firmness value of 40%, which means that APS must supply back-up production capacity for

60% of the self-supply portion of the solar generation to provide reliable service to the solar customer.

Q. HOW DID APS DETERMINE THE COST FOR BACK-UP POWER FOR RESIDENTIAL SOLAR CUSTOMERS?

A. The cost for back-up power for solar customers was determined by first applying the 60% non-firm factor to the total 4-CP of the self-supply portion of solar generation to compute the total amount of back-up power service required from APS. The back-up amount was then multiplied by the average Test Year cost per kW for production capacity for the total residential class to derive the back-up costs included in the COSS. This calculation is detailed in Attachment JRM-06DR.

Q. HOW WERE THE CAPACITY RESERVE COSTS DETERMINED FOR THE COSS?

A. The capacity reserve costs were derived by applying the Company's standard 15% reserve requirement to the 40% firm portion of the solar generation for self-supply at the 4-CP hours. This MW level of required reserves was multiplied by the average cost per kW for production demand for the residential class in the COSS. The reserves for the 60% non-firm portion of the solar generation for self-supply are already captured in the back-up production demand costs because the required back-up MW were evaluated at the average production demand costs for the residential class, which includes the cost of reserves. The results are provided in Attachment JRM-06DR.

Q. ARE ALL THE RESERVES ALREADY CAPTURED IN THE BACK-UP COSTS?

A. No, just the non-firm portion as discussed above. The firm portion of the solar generation, the 40%, also requires reserves just as does APS-supplied power. Firmness and reserves are separate concepts. Firmness provides sufficient and reliable capacity to serve the load of the home under normal or expected conditions.

Reserves provide an additional buffer in case the actual system load or total system generation is significantly different from the expected levels.

Q. PLEASE DISCUSS ADDITIONAL GENERATION SERVICES THAT ARE NOT SUPPLIED BY THE SOLAR GENERATOR.

A. In addition to firm power and reserves, the solar home also needs a variety of generation related services that cannot typically be supplied by the solar generator. These include, for example: (1) the need for the generation to increase and decrease moderately to follow the load in the home in every instant throughout the day, (2) the costs to integrate the solar generator with the utilities entire generation portfolio, (3) the need for the generator to significantly ramp up and down when needed, and (4) the need to provide a significant power burst for a short instant to be able to serve major motor loads, such as an air conditioner compressor.

Like the reserve power costs, these additional generator services will only apply to the non-firm portion of the solar generation used for self-supply—the 60%. These services would already be captured through the conventional generation supplied by APS in the back-up power. The additional cost for these services were evaluated at the cost for similar services in the wholesale power market on a cost per kWh basis and applied to 60% of the total annual kWh of solar generation. The calculation and results are detailed in Attachment JRM-06DR.

Q. ARE THERE SIMILAR COSTS RELATED TO THE TRANSMISSION SYSTEM THAT SOLAR CUSTOMERS CAUSE?

A. Yes. The firmness determination for solar customers related to the transmission system is very similar to that discussed above regarding back-up power. The back-up transmission cost for solar customers was derived by first applying the 60% non-firm factor to the total 4-CP of the self-supply portion of solar generation to compute the total amount of back-up transmission service required from APS.

Then, this back-up amount was multiplied by the average Test Year cost per kW for transmission capacity for the total residential class to derive the back-up costs included in the COSS. This calculation is detailed in Attachment JRM-06DR.

Q. WHAT COST RECOVERY SHOULD SOLAR CUSTOMERS CONTRIBUTE TO THE PRIMARY DISTRIBUTION GRID?

A. Although residential solar generation is located at the home, the customer is still connected to the grid and relies on the grid in two ways: one for reliable electrical service and a second for exporting excess power to the grid. I will address the reliability related costs here and discuss the export related costs separately below.

Similar to production capacity, the utility provides back-up grid services to the solar customer and incurs costs for those services. These are not extra or special costs attributed solely to solar customers. Rather they are standard grid costs that are shared by all customers, that are used by solar customers, but not captured in the allocated cost for the delivered load.

The grid back-up costs are derived in a similar manner to the production capacity back-up costs. A non-firm percentage factor is determined and applied to the self-supply portion of solar generation, and evaluated at the 4-NCP summer hours of the total residential class. The resulting kW of required grid back-up is multiplied by the average cost for the portion of primary grid costs that are allocated on a demand basis to the residential class.

Q. HOW DID YOU ASSESS THE FIRMNESS LEVEL FOR SOLAR POWER CONCERNING THE PRIMARY GRID?

A. The assessment of the solar firmness level for the primary grid is similar to the assessment for production capacity detailed above. It is driven mostly by the availability and dependability of the solar power and to a much lesser extent on the customer optionality factor. The thought process is the same—if the solar power is not completely available during high load hours, if it is not completely dependable when it is available, and if there is no obligation or recourse on the customer to supply the power, then the power is partially non-firm and the utility must step in and provide primary grid services to supply power to the home.

For the primary grid assessment, the solar availability factor is based on the 4-NCP hours in June through September, rather than the 4-CP that was used for production capacity. The other two factors are identical to the assessment for production capacity.

However, in reviewing the 4-CP and 4-NCP hours, the information is very consistent. As shown in Figure 7, most of the CPs and NCPs occur on hour 5 p.m. to 6 p.m., with one of the NCPs occurring on hour 4 p.m. to 5 p.m. Additionally, the monthly NCPs occur within a few days of the CP, with one (August) occurring on the same day and the same hour. In addition, the percentage drop off in load and solar generation in the hours 6 p.m. to 7 p.m. and 7 p.m. to 8 p.m. are almost identical between the 4-CP and 4-NCP assessment.

Given the consistency between the CP and NCP in terms of the availability of solar generation and given that the other three factors are not dependent on CP versus NCP information, the assessment used the same 40% firmness factor (60% non-firm) for solar generation for the primary distribution grid as was used for production and transmission capacity.

Figure 7. Residential Class CP and NCP

June-September Test Year MW

	CP		**NCP**	
	Day	**Hour (pm)**	**Day**	**Hour (pm)**
June	10	5-6	12	5-6
July	8	5-6	10	4-5
August	4	5-6	4	5-6
September	9	5-6	12	5-6

Q. HOW WERE THE PRIMARY GRID BACK-UP COSTS CALCULATED?

A. The back-up cost for the primary grid was derived by applying the 60% non-firm factor to the self-supply portion of solar generation occurring at the 4-NCP of the residential class. This required kW of grid services was multiplied by the average cost per kW for the primary grid for the residential class from the COSS; specifically, the portion of these costs that were allocated by demand. The details and results of this calculation are provided in Attachment JRM-06DR.

Q. HOW DID APS EVALUATE THE GRID COSTS FOR EXPORT POWER?

A. Export power is the solar generation in any instant that is not consumed in the home, but rather flows back to the utility grid. Because the solar customer requires and uses the grid to facilitate export power, those grid costs should be reflected in the COSS. APS derived this cost by applying the average cost per kWh for the primary distribution system for the total residential class to the total kWh of export power. Similar to the calculation of back-up grid costs, the portion of primary costs that were allocated on a customer basis were excluded in this calculation. The data and results are provided in Attachment JRM-06DR.

Q. WHY WASN'T THIS COST EVALUATED USING AN NCP ALLOCATOR?

A. While an NCP allocator is typically used to determine the cost responsibility for primary distribution equipment, that method does not accurately reflect the cost for export power because solar customers export power in many non-peak hours of the year.

Q. WHAT ADDITIONAL SECONDARY DISTRIBUTION COSTS WERE INCLUDED IN THE SOLAR COSS?

A. Secondary distribution costs include equipment such as the line transformer, the service drop and other point-of-delivery items necessary to connect the customer to the grid. The secondary equipment is designed to serve the loads in a home, or a small group of homes. As such, the equipment cannot be re-sized or reduced when a customer installs a solar generator. Further, any excess capacity of secondary equipment cannot be "shared with" or used to serve other homes. Thus, a solar generator does not reduce any secondary distribution costs.

Secondary distribution costs that were already allocated on a customer basis are already included in the COS for the delivered load for the solar class and, therefore, no additional costs need to be added in the solar COSS. However, secondary equipment that were allocated on a demand basis are only partially captured in the COS for delivered load. The remaining portion needs to be added back to the class in the solar COSS.

Q. WAS THE NET COST OR NET VALUE OF THE EXPORT POWER TRANSACTIONS INCLUDED IN APS'S ANALYSIS?

A. Yes. Up to this point, the solar COS has included the elements of solar power that impact the utility's cost of service related to base rates. However, the solar customers also participate in transactions with APS for the export power, where the exports are either net metered on the customer's retail bill or purchased by APS at one of several purchase rates. In addition, the export power has a value to APS, based on avoided costs. Thus, the final element of the solar COS assesses the net cost or net value, whichever is higher, of the export power transactions.

Q. HOW WERE THE AVOIDED COSTS OF THE EXPORT POWER TRANSACTIONS EVALUATED?

A. The export power was valued at the non-firm avoided cost rate in rate schedule EPR-6, which is the rate at which net metering customers sell back excess power at the end of the year. The non-firm designation and value is appropriate here because the export power is a random flow of energy at any instant, rather than a certain amount that can be relied on or called upon by APS when needed. There are no obligations on the customer to supply a certain amount of power or any repercussions for not delivering power when requested.

Q. HOW WERE THE EXPORT PURCHASE COSTS DETERMINED?

A. As explained above, some of the export power is net metered on the customer's bill, while other amounts are purchased at one of APS's purchase rates. The latter includes rate rider schedules EPR-2, EPR-6, and RCP.

The net metered power is already factored into the assessment because the COSS compares the cost of service with the annual class revenue during the Test Year, which is already reduced by the net-metered amounts.

The export power that was purchased at the three purchase rates was included as recorded in our power accounting system for the Test Year. These amounts were also tested with individual calculations of the amount of export energy for each category multiplied by the applicable purchase rate, to ensure consistency with the value side of the calculation. The cost of EPR-2 and EPR-6 purchases are essentially a wash with the value side of the computation because the purchase rates are based on, and equal to, the non-firm avoided cost value of transaction. However, because the export energy for these purchases were included in the export value, they also need to be included in the export purchase cost for consistency.

Q. WHAT WAS THE NET IMPACT OF THE EXPORT POWER TRANSACTIONS?

A. The net impact to the COSS from the export power transactions were $49.3 million. The details are provided in Attachment JRM-06DR.

Q. WHAT ARE THE OVERALL RESULTS OF THE SOLAR COSS FROM A BOTTOM-UP PERSPECTIVE?

A. Overall, with all the adjustments discussed, the results of the COSS for the solar classes are shown below in Figure 8.

Figure 8. Solar Cost of Service

(Bottom-Up Approach)

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
% COS Recovered	**34.8%**	**63.2%**	**47.0%**	**51.9%**

X. <u>FAIR VALUE RATE OF RETURN</u>

Q. WHAT IS APS'S FVRB AND RATE OF RETURN FOR THE ADJUSTED TEST YEAR?

A. As shown on SFR Schedule A-1, APS's FVRB is $16.6 billion and the current fair value rate of return (FVROR) is 1.43% as reflected on SFR Schedule A-1, line 3.

Q. HOW WAS THE FAIR VALUE RATE BASE DETERMINED?

A. APS used the Commission approved methodology of averaging the OCRB and RCND in the calculation of FVRB. APS witness Elizabeth A. Blankenship's testimony describes this calculation in more detail.

Q. DID APS PERFORM A CALCULATION TO ADDRESS THE APPROPRIATE LEVEL OF RETURN ON FVRB?

A. Yes. The after-tax return on the Fair Value Increment (FVI) is shown on SFR Schedule A-1, line 9, and the calculation is shown in Attachment JRM-07DR.

Q. IS THE TREATMENT CONSISTENT WITH THE METHOD USED IN APS'S LAST RATE CASE?

A. Yes.

Q. CAN YOU EXPLAIN HOW THE FAIR VALUE RATE OF RETURN WAS CALCULATED?

A. Generally, APS calculated the rate of return to be applied to the fair value rate base (FVRB) as follows:

- FVRB is divided into three components:

  (1) The FVI is calculated by subtracting the OCRB from the FVRB to determine the portion of FVRB in excess of the OCRB;

  (2) Debt component of OCRB is calculated by multiplying the Company's adjusted Test Year debt percentage (48.07%) by the OCRB; and

  (3) Equity component of OCRB is calculated by multiplying the Company's adjusted Test Year equity percentage (51.93%) by the OCRB.

- Next, a return component of 1.0% is applied to the FVI. Using the 1.0% return for the FVI, 3.85% return on the debt component and 10.25% on the equity component, a new fair value weighted average cost of capital is calculated.

- The fair value weighted average cost of capital is applied to the FVRB and the result is compared to the original cost increase in revenue requirement of $689.5 million reflected on SFR Schedule A-1, line 8. The difference between those two values indicates that the after-tax return on the FVI is $82.8 million, as reflected on SFR Schedule A-1, line 9. Further detail is provided in Attachment JRM-07DR.

XI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Index for Sponsorship of Standard Filing Requirements	
SFR Number	**Witness**
A-1	Mr. Moe
A-2*, A-3, A-4, A-5	Ms. Blankenship
B-1*, B-2*[1], B-3*, B-4, B-4a*, B-5	Ms. Blankenship
C-1*	Ms. Blankenship
C-2*[1] (Columns 1-5)	Ms. Blankenship
C-2 (Columns 6-8)	Mr. Moe
C-2*(Columns 9-10, 19, 22-24)	Ms. Hobbick
C-2* (Columns 11-13, 20, 25-59)	Ms. Blankenship
C-2* (Columns 14-16, 18) [2]	Ms. Hobbick/Ms. Blankenship
C-3	Ms. Blankenship
D-1, D-2, D-3, D-4	Ms. Blankenship
E-1, E-2, E-3, E-4, E-5, E-6, E-7, E-8, E-9	Ms. Blankenship
F-1*, F-2, F-3, F-4	Ms. Blankenship
G-1, G-2, G-3, G-4, G-5, G-6, G-7	Mr. Moe
H-1, H-2, H-3, H-4, H-5	Ms. Hobbick

*Mr. Moe sponsors the ACC jurisdictional amounts that are computed based on the Cost of Service Study.

[1]Mr. Tetlow discusses the details of post-Test Year plant projects included in the pro formas

[2]Ms. Hobbick address the rate impacts of the proposed adjustment mechanism pro formas

ARIZONA PUBLIC SERVICE COMPANY

Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Site Load

				RETAIL					
SUMMARY OF RESULTS	**ELECTRIC TOTAL**	**ALL OTHER**	**ACC JURISDICTION**	**RESIDENTIAL**	**GENERAL SERVICE**	**E-221 NonAG**	**E-221 AG**	**Street Lighting**	**Dusk to Dawn**
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 9,832,767,730	$ 12,364,736	$ 9,820,402,994	$ 5,644,799,323	$ 4,082,038,221	$ 72,753,671	$ -	$ 17,771,176	$ 3,040,603
TRANSMISSION PLANT IN SERVICE	3,414,532,481	3,414,532,481	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	7,763,311,806	47,825	7,763,263,981	5,771,375,635	1,782,547,308	39,319,272	-	107,314,282	62,707,483
GENERAL & INTANGIBLE PLANT	2,381,362,366	201,416,194	2,179,946,172	1,453,304,722	704,067,273	13,388,009	-	5,155,410	4,030,757
LESS: RESERVE FOR DEPRECIATION	(8,525,604,548)	(1,097,516,640)	(7,428,087,908)	(4,725,933,842)	(2,593,273,764)	(48,993,629)	-	(39,405,564)	(20,481,109)
MATERIALS, SUPPLIES & PREPAYMENTS	611,970,887	60,472,722	551,498,165	330,308,502	212,708,503	4,215,207	-	2,947,009	1,318,944
MISCELLANEOUS DEFERRED DEBITS	30,089,000	1,720,232	28,368,768	17,044,088	10,988,967	218,082	-	81,530	36,100
OTHER DEFERRED CREDITS	(1,293,452,000)	(17,026,530)	(1,276,425,470)	(727,913,564)	(534,912,652)	(9,913,421)	-	(2,973,607)	(712,226)
OPEB	568,515,119	50,048,476	518,466,642	340,355,139	172,685,905	3,309,901	-	1,257,084	858,614
WORKING CASH	(105,488,059)	(25,067,681)	(80,420,378)	(56,857,229)	(21,946,896)	(396,727)	-	(775,431)	(444,095)
REGULATORY ASSETS	(824,250,000)	41,487,508	(865,737,508)	(545,026,594)	(305,547,855)	(5,845,629)	-	(6,239,475)	(3,077,956)
ACCUM. DEFERRED TAXES	(2,354,271,572)	(1,460,221)	(2,352,811,351)	(1,539,735,347)	(772,580,780)	(14,868,658)	-	(16,688,709)	(8,937,857)
OPERATING LEASES	22,468,854	5,217,275	17,251,579	16,988,475	228,891	(24,596)	-	(6,920)	65,729
DECOMMISSIONING FUND	1,422,493,893	1,706,993	1,420,786,900	812,175,200	594,760,584	10,692,502	-	2,695,501	463,112
CUSTOMER ADVANCES	(336,198,398)	(30,943,932)	(305,254,466)	(59,671,221)	(244,998,747)	(12,256)	-	(571,951)	(290)
CUSTOMER DEPOSITS	(40,062,749)	-	(40,062,749)	(10,971,370)	(28,113,431)	(604,946)	-	(373,003)	-
PROFORMA ADJUSTMENTS	578,176,449	13,487,964	564,688,485	346,787,908	210,941,965	3,916,486	-	2,074,849	967,277
TOTAL RATE BASE	**13,146,361,258**	**2,630,487,403**	**10,515,873,855**	**7,067,029,827**	**3,269,593,492**	**67,153,269**	**-**	**72,262,181**	**39,835,086**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,468,594,702	70,581,514	3,398,013,188	1,822,674,883	1,514,041,713	32,579,215	-	20,087,962	8,629,415
PRO FORMA TO BASE REVENUES FROM RATES	(21,200,909)	-	(21,200,909)	(3,365,597)	(14,959,440)	(2,243,274)	-	(790,435)	157,837
SURCHARGE & OTHER ELECTRIC REVENUES	513,230,298	51,966,846	461,263,452	255,683,960	198,871,253	4,903,633	-	1,432,620	371,985
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(209,593,326)	(181,152)	(209,412,174)	(125,392,120)	(80,790,128)	(2,446,293)	-	(569,054)	(214,579)
TOTAL OPERATING REVENUES	**3,751,030,765**	**122,367,208**	**3,628,663,557**	**1,949,601,127**	**1,617,163,399**	**32,793,281**	**-**	**20,161,093**	**8,944,658**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,021,289,826	(210,227,344)	2,231,517,171	1,208,003,895	993,085,522	21,984,448	-	6,569,697	1,873,608
ADMINISTRATIVE & GENERAL	169,603,050	19,344,934	150,258,116	99,361,524	49,309,448	945,539	-	377,981	263,624
DEPRECIATION & AMORT EXPENSE	677,267,319	82,200,289	595,067,030	383,811,293	202,226,210	3,862,423	-	3,366,763	1,800,340
OTHER EXPENSE ITEMS	26,436,176	2	26,436,174	15,111,845	11,066,601	198,955	-	50,156	8,617
TAXES OTHER THAN INCOME	227,125,941	39,350,683	187,775,259	126,833,797	57,157,070	1,133,875	-	1,709,652	940,865
PROFORMA ADJUSTMENTS	231,114,792	4,279,233	226,835,560	132,927,318	91,461,249	1,382,428	-	795,085	269,479
INCOME TAX	115,485,000	30,375,547	85,109,453	7,597,844	73,243,946	1,800,893	-	1,760,406	706,364
PROFORMA INCOME TAX ADJUSTMENTS	(113,749,642)	(1,563,146)	(112,186,496)	(64,035,299)	(46,065,908)	(1,496,407)	-	(516,963)	(71,919)
TOTAL OPERATING EXPENSES	**3,354,572,462**	**(36,239,804)**	**3,390,812,266**	**1,909,612,217**	**1,431,484,138**	**29,812,153**	**-**	**14,112,779**	**5,790,979**
OPERATING INCOME	**396,458,303**	**158,607,012**	**237,851,291**	**39,988,910**	**185,679,261**	**2,981,128**	**0**	**6,048,314**	**3,153,679**
RATE OF RETURN (PRESENT)	**3.02%**	**6.03%**	**2.26%**	**0.57%**	**5.68%**	**4.44%**	**0.00%**	**8.37%**	**7.92%**
INDEX RATE OF RETURN (PRESENT)	**1.0**	**2.0**	**0.8**	**0.2**	**1.9**	**1.5**	**-**	**2.8**	**2.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**4,259,739,586**	**110,656,184**	**4,149,083,401**	**2,497,857,334**	**1,590,509,398**	**33,326,209**	**0**	**18,697,489**	**8,692,971**
% OF TOTAL COST OF SERVICE (PRESENT)	**81.78%**	**63.79%**	**82.26%**	**74.11%**	**94.48%**	**94.01%**	**0.00%**	**102.81%**	**100.99%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**99.06%**	**63.79%**	**100.00%**	**89.44%**	**115.89%**	**116.14%**		**122.45%**	**116.76%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Site Load

	RESIDENTIAL								
SUMMARY OF RESULTS	**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	$ 488,801,299	$ 13,765,408	$ 226,940,302	$ 96,984,231	$ 729,443,030	$ 333,238,314	$ 132,175,064	$ 1,502,184,094	$ 2,121,267,582
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	427,762,293	10,724,735	236,059,559	88,538,724	1,113,504,688	373,356,538	118,752,094	1,509,174,525	1,893,502,478
GENERAL & INTANGIBLE PLANT	109,156,454	2,816,987	58,213,002	22,462,917	278,467,494	92,327,987	30,618,593	373,092,955	486,148,333
LESS: RESERVE FOR DEPRECIATION	(379,654,765)	(10,202,046)	(190,961,228)	(76,946,073)	(764,140,288)	(291,241,266)	(104,239,278)	(1,241,552,584)	(1,666,996,313)
MATERIALS, SUPPLIES & PREPAYMENTS	26,739,791	743,388	13,327,217	5,533,161	51,312,979	19,786,828	7,389,155	86,526,572	118,949,412
MISCELLANEOUS DEFERRED DEBITS	1,339,970	36,863	682,964	279,725	2,880,052	1,031,507	374,707	4,404,758	6,013,543
OTHER DEFERRED CREDITS	(61,948,660)	(1,754,410)	(29,247,255)	(12,504,593)	(98,592,720)	(42,789,137)	(16,895,238)	(192,426,130)	(271,755,422)
OPEB	25,859,221	673,719	13,638,113	5,312,496	63,508,712	21,481,611	7,233,324	87,635,388	115,012,553
WORKING CASH	(4,536,575)	(116,559)	(2,319,690)	(898,466)	(9,451,920)	(3,624,723)	(1,229,536)	(15,117,204)	(19,562,556)
REGULATORY ASSETS	(44,639,510)	(1,214,710)	(22,121,674)	(9,034,717)	(82,797,897)	(33,225,316)	(12,177,874)	(144,412,359)	(195,402,538)
ACCUM. DEFERRED TAXES	(122,483,951)	(3,256,157)	(62,415,890)	(24,862,531)	(254,697,399)	(95,687,809)	(33,621,425)	(405,102,179)	(537,608,004)
OPERATING LEASES	1,138,283	22,664	680,903	216,536	4,205,551	1,230,754	317,700	4,325,906	4,850,179
DECOMMISSIONING FUND	70,243,803	1,984,461	32,647,555	13,986,632	105,045,499	47,806,061	19,021,321	215,934,354	305,505,512
CUSTOMER ADVANCES	(1,941,352)	(100,878)	(1,869,304)	(803,835)	(8,858,012)	(3,752,413)	(1,696,196)	(17,798,968)	(22,850,262)
CUSTOMER DEPOSITS	(351,849)	(18,477)	(342,859)	(147,442)	(1,630,471)	(690,312)	(312,342)	(3,275,644)	(4,201,973)
PROFORMA ADJUSTMENTS	28,397,420	775,078	13,970,168	5,731,016	53,304,189	21,095,894	7,776,847	91,239,274	124,498,021
TOTAL RATE BASE	**563,881,873**	**14,880,066**	**286,881,882**	**113,847,782**	**1,181,503,488**	**440,344,517**	**153,486,917**	**1,854,832,757**	**2,457,370,546**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	58,452,741	3,069,538	56,959,275	24,494,557	270,870,328	114,681,673	51,889,334	544,183,153	698,074,284
PRO FORMA TO BASE REVENUES FROM RATES	(456,828)	(54,668)	(1,257,216)	(494,918)	8,763,675	(3,471,297)	1,613,889	(17,040,346)	9,032,112
SURCHARGE & OTHER ELECTRIC REVENUES	15,307,364	514,359	9,021,273	4,047,971	39,309,902	15,148,017	6,130,360	68,154,430	98,050,286
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(4,302,104)	(182,825)	(3,709,741)	(1,676,257)	(22,282,606)	(7,959,670)	(3,066,291)	(34,194,016)	(48,018,610)
TOTAL OPERATING REVENUES	**69,001,173**	**3,346,404**	**61,013,591**	**26,371,353**	**296,661,299**	**118,398,723**	**56,567,292**	**561,103,221**	**757,138,072**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	50,406,025	1,749,933	59,451,893	22,721,124	186,056,505	71,820,650	28,887,368	324,176,421	462,733,975
ADMINISTRATIVE & GENERAL	7,520,578	195,105	3,982,079	1,544,893	18,705,855	6,289,912	2,104,691	25,571,221	33,447,191
DEPRECIATION & AMORT EXPENSE	30,489,298	813,363	15,512,975	6,198,830	63,872,121	23,791,468	8,392,892	100,607,483	134,132,864
OTHER EXPENSE ITEMS	1,306,999	36,924	607,461	260,245	1,954,544	889,508	353,923	4,017,808	5,684,433
TAXES OTHER THAN INCOME	9,926,018	260,540	5,157,826	2,025,608	21,769,882	7,957,452	2,730,526	33,352,108	43,653,837
PROFORMA ADJUSTMENTS	14,602,470	426,680	5,817,556	2,659,724	17,175,327	5,734,260	3,285,072	29,078,911	54,147,318
INCOME TAX	(10,646,375)	17,732	(6,783,054)	(1,898,999)	(4,299,673)	1,425,617	2,685,800	16,851,473	10,245,322
PROFORMA INCOME TAX ADJUSTMENTS	(4,735,333)	(162,873)	(2,638,975)	(1,183,798)	(7,475,604)	(4,201,770)	(1,157,242)	(19,679,356)	(22,800,347)
TOTAL OPERATING EXPENSES	**98,869,679**	**3,337,405**	**81,107,761**	**32,327,626**	**297,758,959**	**113,707,095**	**47,283,030**	**513,976,068**	**721,244,594**
OPERATING INCOME	**(29,868,506)**	**8,999**	**(20,094,170)**	**(5,956,273)**	**(1,097,660)**	**4,691,627**	**9,284,262**	**47,127,153**	**35,893,478**
RATE OF RETURN (PRESENT)	**-5.30%**	**0.06%**	**-7.00%**	**-5.23%**	**-0.09%**	**1.07%**	**6.05%**	**2.54%**	**1.46%**
INDEX RATE OF RETURN (PRESENT)	**(1.8)**	**0.0**	**(2.3)**	**(1.7)**	**(0.0)**	**0.4**	**2.0**	**0.8**	**0.5**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**156,307,569**	**4,544,814**	**112,258,160**	**43,751,715**	**403,415,266**	**150,538,939**	**57,001,143**	**656,297,368**	**913,742,360**
% OF TOTAL COST OF SERVICE (PRESENT)	**37.73%**	**68.04%**	**50.38%**	**56.22%**	**70.44%**	**75.08%**	**95.25%**	**81.63%**	**78.86%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**45.56%**	**81.45%**	**60.41%**	**69.56%**	**85.12%**	**90.72%**	**115.26%**	**98.72%**	**94.92%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Site Load

	GENERAL SERVICE								
SUMMARY OF RESULTS	**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	$ 12,160,381	$ 5,579,743	$ 8,269,436	$ 30,602,927	$ 77,074,903	$ 53,274,445	$ 512,732,873	$ 795,188,536	$ 914,636,571
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	10,547,706	3,928,185	3,861,969	11,002,846	25,819,833	31,984,511	497,065,199	384,921,647	342,574,123
GENERAL & INTANGIBLE PLANT	2,445,496	1,214,554	1,469,386	4,792,058	11,769,093	8,672,309	134,584,485	146,015,666	140,898,091
LESS: RESERVE FOR DEPRECIATION	(9,260,148)	(4,104,653)	(5,343,821)	(18,588,426)	(46,047,273)	(35,767,346)	(425,372,911)	(518,926,029)	(554,997,907)
MATERIALS, SUPPLIES & PREPAYMENTS	672,766	332,228	434,043	1,617,636	3,951,065	2,866,356	31,302,821	40,606,126	45,650,594
MISCELLANEOUS DEFERRED DEBITS	32,668	17,402	22,573	82,749	201,571	137,750	1,656,371	2,129,779	2,302,222
OTHER DEFERRED CREDITS	(1,550,039)	(756,154)	(1,083,437)	(4,075,355)	(10,148,279)	(6,928,098)	(68,177,331)	(102,640,818)	(118,319,355)
OPEB	602,126	289,809	362,935	1,190,276	2,925,795	2,152,613	31,489,704	36,000,089	34,968,476
WORKING CASH	(111,203)	(37,811)	(46,341)	(138,153)	(349,419)	(361,739)	(4,672,280)	(4,762,256)	(4,709,748)
REGULATORY ASSETS	(1,123,463)	(479,000)	(626,526)	(2,231,525)	(5,518,937)	(4,438,012)	(48,569,682)	(60,059,151)	(66,559,654)
ACCUM. DEFERRED TAXES	(3,020,346)	(1,273,263)	(1,602,860)	(5,447,087)	(13,437,246)	(11,191,450)	(136,604,844)	(156,227,494)	(164,192,403)
OPERATING LEASES	21,251	3,935	2,345	(23,813)	(51,285)	587	1,274,737	631,860	(217,911)
DECOMMISSIONING FUND	1,752,220	816,547	1,204,013	4,484,015	11,264,979	7,747,836	74,342,056	115,275,494	133,048,734
CUSTOMER ADVANCES	(505,673)	(380,282)	(503,612)	(1,333,752)	(3,444,317)	(2,425,196)	(31,915,380)	(40,834,324)	(44,067,912)
CUSTOMER DEPOSITS	(73,495)	(55,316)	(73,245)	(193,861)	(500,661)	(352,540)	(4,641,920)	(5,937,292)	(6,406,665)
PROFORMA ADJUSTMENTS	694,802	317,780	432,230	1,540,647	3,835,158	2,811,882	31,538,290	41,785,723	45,728,213
TOTAL RATE BASE	**13,285,049**	**5,413,704**	**6,779,087**	**23,281,182**	**57,344,978**	**48,183,908**	**596,032,187**	**673,167,555**	**700,335,468**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,958,051	2,979,043	3,944,581	10,440,351	26,962,992	18,985,953	249,989,443	319,751,351	345,029,300
PRO FORMA TO BASE REVENUES FROM RATES	(51,315)	64,393	(248,666)	(524,002)	2,512,750	(240,838)	(3,267,610)	(3,615,921)	(4,925,494)
SURCHARGE & OTHER ELECTRIC REVENUES	563,836	385,003	474,487	1,507,987	3,447,597	2,673,587	30,357,537	43,080,394	45,613,844
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(271,375)	(212,394)	(236,290)	(526,766)	(1,110,721)	(1,162,244)	(16,682,851)	(21,841,740)	(19,790,485)
TOTAL OPERATING REVENUES	**4,199,197**	**3,216,044**	**3,934,112**	**10,897,569**	**31,812,618**	**20,256,458**	**260,396,519**	**337,374,083**	**365,927,166**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,882,082	1,561,672	2,030,311	7,443,789	18,081,818	13,597,127	132,496,905	190,870,127	212,800,995
ADMINISTRATIVE & GENERAL	174,646	83,505	103,866	337,248	828,760	615,551	9,168,890	10,337,005	9,939,782
DEPRECIATION & AMORT EXPENSE	743,035	327,566	418,768	1,436,225	3,546,477	2,804,897	34,534,062	40,787,325	42,860,244
OTHER EXPENSE ITEMS	32,603	15,193	22,403	83,434	209,606	144,162	1,383,264	2,144,901	2,475,610
TAXES OTHER THAN INCOME	245,808	100,119	119,412	395,307	966,477	872,680	11,153,375	11,654,488	11,964,822
PROFORMA ADJUSTMENTS	280,829	71,413	64,546	776,497	3,162,866	1,913,376	7,406,075	13,225,635	20,597,937
INCOME TAX	7,733	273,258	373,265	373,669	1,223,904	518,320	18,088,314	21,260,407	21,834,405
PROFORMA INCOME TAX ADJUSTMENTS	(147,909)	(53,794)	(135,396)	(450,293)	(431,935)	(815,547)	(6,708,113)	(9,520,283)	(11,157,074)
TOTAL OPERATING EXPENSES	**4,218,827**	**2,378,933**	**2,997,175**	**10,395,874**	**27,587,971**	**19,650,566**	**207,522,773**	**280,759,606**	**311,316,723**
OPERATING INCOME	**(19,630)**	**837,112**	**936,938**	**501,695**	**4,224,647**	**605,893**	**52,873,746**	**56,614,477**	**54,610,443**
RATE OF RETURN (PRESENT)	**-0.15%**	**15.46%**	**13.82%**	**2.15%**	**7.37%**	**1.26%**	**8.87%**	**8.41%**	**7.80%**
INDEX RATE OF RETURN (PRESENT)	**(0.0)**	**5.1**	**4.6**	**0.7**	**2.4**	**0.4**	**2.9**	**2.8**	**2.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**5,309,556**	**2,486,970**	**3,148,017**	**11,665,247**	**29,790,044**	**22,935,047**	**237,863,709**	**310,350,664**	**339,869,498**
% OF TOTAL COST OF SERVICE (PRESENT)	**75.64%**	**122.56%**	**117.97%**	**85.46%**	**98.04%**	**84.19%**	**104.59%**	**102.99%**	**100.89%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**91.06%**	**151.44%**	**145.29%**	**105.22%**	**122.58%**	**101.48%**	**128.36%**	**126.06%**	**124.03%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Site Load

SUMMARY OF RESULTS	GENERAL SERVICE E-32 (401+ kW)	E-34	E-35	AG-X
DEVELOPMENT OF RATE BASE				
PRODUCTION PLANT IN SERVICE	$ 742,288,876	$ 165,390,653	$ 509,157,006	$ 255,681,872
TRANSMISSION PLANT IN SERVICE	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	249,726,692	43,002,737	114,822,244	63,289,617
GENERAL & INTANGIBLE PLANT	112,720,666	24,744,695	76,652,908	38,087,866
LESS: RESERVE FOR DEPRECIATION	(443,091,368)	(95,361,908)	(289,804,980)	(146,606,994)
MATERIALS, SUPPLIES & PREPAYMENTS	37,759,747	8,395,890	26,129,012	12,990,218
MISCELLANEOUS DEFERRED DEBITS	1,920,565	435,534	1,374,309	675,474
OTHER DEFERRED CREDITS	(97,362,086)	(21,895,160)	(68,060,087)	(33,916,454)
OPEB	28,019,416	6,153,148	19,061,616	9,469,902
WORKING CASH	(3,424,888)	(638,631)	(1,740,757)	(953,668)
REGULATORY ASSETS	(53,150,663)	(11,312,539)	(34,111,854)	(17,366,848)
ACCUM. DEFERRED TAXES	(129,472,511)	(27,162,737)	(81,388,376)	(41,560,163)
OPERATING LEASES	(453,703)	(150,147)	(558,969)	(249,997)
DECOMMISSIONING FUND	108,391,564	24,219,412	74,749,071	37,464,644
CUSTOMER ADVANCES	(33,111,143)	(4,891,691)	(71,283,271)	(10,302,194)
CUSTOMER DEPOSITS	(4,812,982)	(710,299)	(2,857,985)	(1,497,169)
PROFORMA ADJUSTMENTS	36,877,857	8,090,630	24,817,250	12,471,504
TOTAL RATE BASE	**552,826,039**	**118,309,588**	**296,957,137**	**177,677,609**
DEVELOPMENT OF RETURN				
BASE REVENUES FROM RATES	259,201,950	38,252,968	153,916,079	80,629,651
PRO FORMA TO BASE REVENUES FROM RATES	304,925	2,210,724	(5,836,221)	(1,342,165)
SURCHARGE & OTHER ELECTRIC REVENUES	33,914,431	7,477,244	24,217,213	5,158,094
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(11,674,669)	(2,299,744)	(7,790,126)	2,809,278
TOTAL OPERATING REVENUES	**281,746,637**	**45,641,193**	**164,506,945**	**87,254,858**
OPERATING EXPENSES				
OPERATION & MAINTENANCE	174,962,433	40,524,545	127,343,842	68,489,878
ADMINISTRATIVE & GENERAL	7,938,614	1,737,196	5,372,885	2,671,500
DEPRECIATION & AMORT EXPENSE	34,114,284	7,299,435	22,144,386	11,209,505
OTHER EXPENSE ITEMS	2,016,825	450,648	1,390,850	697,101
TAXES OTHER THAN INCOME	9,318,267	1,895,042	5,587,087	2,884,186
PROFORMA ADJUSTMENTS	19,572,255	6,536,884	13,110,803	4,742,134
INCOME TAX	11,657,985	(2,451,006)	1,523,237	(1,439,545)
PROFORMA INCOME TAX ADJUSTMENTS	(7,616,253)	(1,632,430)	(6,595,338)	(801,544)
TOTAL OPERATING EXPENSES	**251,964,411**	**54,360,314**	**169,877,751**	**88,453,215**
OPERATING INCOME	**29,782,226**	**(8,719,121)**	**(5,370,807)**	**(1,198,358)**
RATE OF RETURN (PRESENT)	**5.39%**	**-7.37%**	**-1.81%**	**-0.67%**
INDEX RATE OF RETURN (PRESENT)	**1.8**	**(2.4)**	**(0.6)**	**(0.2)**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**277,152,418**	**64,408,170**	**186,169,924**	**99,360,135**
% OF TOTAL COST OF SERVICE (PRESENT)	**92.91%**	**62.61%**	**78.82%**	**78.05%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**117.75%**	**92.28%**	**94.31%**	**79.15%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Combined

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	$ 9,832,767,730	$ 12,364,736	$ 9,820,402,994	$ 5,644,799,323	$ 4,082,038,221	$ 72,753,671	$ -	$ 17,771,176	$ 3,040,603
TRANSMISSION PLANT IN SERVICE	3,414,532,481	3,414,532,481	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	7,763,311,806	47,825	7,763,263,981	5,771,375,635	1,782,547,308	39,319,272	-	107,314,282	62,707,483
GENERAL & INTANGIBLE PLANT	2,381,362,366	201,416,194	2,179,946,172	1,453,304,722	704,067,273	13,388,009	-	5,155,410	4,030,757
LESS: RESERVE FOR DEPRECIATION	(8,525,604,548)	(1,097,516,640)	(7,428,087,908)	(4,725,933,842)	(2,593,273,764)	(48,993,629)	-	(39,405,564)	(20,481,109)
MATERIALS, SUPPLIES & PREPAYMENTS	611,970,887	60,472,722	551,498,165	330,308,502	212,708,503	4,215,207	-	2,947,009	1,318,944
MISCELLANEOUS DEFERRED DEBITS	30,089,000	1,720,232	28,368,768	17,044,088	10,988,967	218,082	-	81,530	36,100
OTHER DEFERRED CREDITS	(1,293,452,000)	(17,026,530)	(1,276,425,470)	(727,913,564)	(534,912,652)	(9,913,421)	-	(2,973,607)	(712,226)
OPEB	568,515,119	50,048,476	518,466,642	340,355,139	172,685,905	3,309,901	-	1,257,084	858,614
WORKING CASH	(105,488,059)	(25,067,681)	(80,420,378)	(56,857,229)	(21,946,896)	(396,727)	-	(775,431)	(444,095)
REGULATORY ASSETS	(824,250,000)	41,487,508	(865,737,508)	(545,026,594)	(305,547,855)	(5,845,629)	-	(6,239,475)	(3,077,956)
ACCUM. DEFERRED TAXES	(2,354,271,572)	(1,460,221)	(2,352,811,351)	(1,539,735,347)	(772,580,780)	(14,868,658)	-	(16,688,709)	(8,937,857)
OPERATING LEASES	22,468,854	5,217,275	17,251,579	16,988,475	228,891	(24,596)	-	(6,920)	65,729
DECOMMISSIONING FUND	1,422,493,893	1,706,993	1,420,786,900	812,175,200	594,760,584	10,692,502	-	2,695,501	463,112
CUSTOMER ADVANCES	(336,198,398)	(30,943,932)	(305,254,466)	(59,671,221)	(244,998,747)	(12,256)	-	(571,951)	(290)
CUSTOMER DEPOSITS	(40,062,749)	-	(40,062,749)	(10,971,370)	(28,113,431)	(604,946)	-	(373,003)	-
PROFORMA ADJUSTMENTS	578,176,449	13,487,964	564,688,485	346,787,908	210,941,965	3,916,486	-	2,074,849	967,277
TOTAL RATE BASE	**13,146,361,258**	**2,630,487,403**	**10,515,873,855**	**7,067,029,827**	**3,269,593,492**	**67,153,269**	**-**	**72,262,181**	**39,835,086**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,468,594,702	70,581,514	3,398,013,188	1,822,674,883	1,514,041,713	32,579,215	-	20,087,962	8,629,415
PRO FORMA TO BASE REVENUES FROM RATES	(21,200,909)	-	(21,200,909)	(3,365,597)	(14,959,440)	(2,243,274)	-	(790,435)	157,837
SURCHARGE & OTHER ELECTRIC REVENUES	513,230,298	51,966,846	461,263,452	255,683,960	198,871,253	4,903,633	-	1,432,620	371,985
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(209,593,326)	(181,152)	(209,412,174)	(125,392,120)	(80,790,128)	(2,446,293)	-	(569,054)	(214,579)
TOTAL OPERATING REVENUES	**3,751,030,765**	**122,367,208**	**3,628,663,557**	**1,949,601,127**	**1,617,163,399**	**32,793,281**	**-**	**20,161,093**	**8,944,658**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,021,289,826	(210,227,344)	2,231,517,171	1,208,003,895	993,085,522	21,984,448	-	6,569,697	1,873,608
ADMINISTRATIVE & GENERAL	169,603,050	19,344,934	150,258,116	99,361,524	49,309,448	945,539	-	377,981	263,624
DEPRECIATION & AMORT EXPENSE	677,267,319	82,200,289	595,067,030	383,811,293	202,226,210	3,862,423	-	3,366,763	1,800,340
OTHER EXPENSE ITEMS	26,436,176	2	26,436,174	15,111,845	11,066,601	198,955	-	50,156	8,617
TAXES OTHER THAN INCOME	227,125,941	39,350,683	187,775,259	126,833,797	57,157,070	1,133,875	-	1,709,652	940,865
PROFORMA ADJUSTMENTS	231,114,792	4,279,233	226,835,560	132,927,318	91,461,249	1,382,428	-	795,085	269,479
INCOME TAX	115,485,000	30,375,547	85,109,453	7,597,844	73,243,946	1,800,893	-	1,760,406	706,364
PROFORMA INCOME TAX ADJUSTMENTS	(113,749,642)	(1,563,146)	(112,186,496)	(64,035,299)	(46,065,908)	(1,496,407)	-	(516,963)	(71,919)
TOTAL OPERATING EXPENSES	**3,354,572,462**	**(36,239,804)**	**3,390,812,266**	**1,909,612,217**	**1,431,484,138**	**29,812,153**	**-**	**14,112,779**	**5,790,979**
OPERATING INCOME	**396,458,303**	**158,607,012**	**237,851,291**	**39,988,910**	**185,679,261**	**2,981,128**	**0**	**6,048,314**	**3,153,679**
RATE OF RETURN (PRESENT)	**3.02%**	**6.03%**	**2.26%**	**0.57%**	**5.68%**	**4.44%**	**0.00%**	**8.37%**	**7.92%**
INDEX RATE OF RETURN (PRESENT)	**1.0**	**2.0**	**0.8**	**0.2**	**1.9**	**1.5**	**-**	**2.8**	**2.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**4,259,739,586**	**110,656,184**	**4,149,083,401**	**2,497,857,334**	**1,590,509,398**	**33,326,209**	**0**	**18,697,489**	**8,692,971**
% OF TOTAL COST OF SERVICE (PRESENT)	**81.78%**	**63.79%**	**82.26%**	**74.11%**	**94.48%**	**94.01%**	**0.00%**	**102.81%**	**100.99%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**99.06%**	**63.79%**	**100.00%**	**89.44%**	**115.89%**	**116.14%**		**122.45%**	**116.76%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Combined

	RESIDENTIAL						
SUMMARY OF RESULTS	**Legacy Solar (Energy)**	**Legacy Solar (Demand)**	**R-Basic (0-600kW)**	**R-Basic (601-999 kW)**	**R-Basic (1000+ kW)**	**R-TOU & R-Solar TOU**	**R-Demand & R-Solar (Demand)**
DEVELOPMENT OF RATE BASE							
PRODUCTION PLANT IN SERVICE	$ 488,801,299	$ 13,765,408	$ 729,443,030	$ 333,238,314	$ 132,175,064	$ 1,729,124,395	$ 2,218,251,813
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	427,762,293	10,724,735	1,113,504,688	373,356,538	118,752,094	1,745,234,085	1,982,041,202
GENERAL & INTANGIBLE PLANT	109,156,454	2,816,987	278,467,494	92,327,987	30,618,593	431,305,957	508,611,251
LESS: RESERVE FOR DEPRECIATION	(379,654,765)	(10,202,046)	(764,140,288)	(291,241,266)	(104,239,278)	(1,432,513,813)	(1,743,942,386)
MATERIALS, SUPPLIES & PREPAYMENTS	26,739,791	743,388	51,312,979	19,786,828	7,389,155	99,853,789	124,482,573
MISCELLANEOUS DEFERRED DEBITS	1,339,970	36,863	2,880,052	1,031,507	374,707	5,087,722	6,293,268
OTHER DEFERRED CREDITS	(61,948,660)	(1,754,410)	(98,592,720)	(42,789,137)	(16,895,238)	(221,673,385)	(284,260,015)
OPEB	25,859,221	673,719	63,508,712	21,481,611	7,233,324	101,273,502	120,325,050
WORKING CASH	(4,536,575)	(116,559)	(9,451,920)	(3,624,723)	(1,229,536)	(17,436,894)	(20,461,022)
REGULATORY ASSETS	(44,639,510)	(1,214,710)	(82,797,897)	(33,225,316)	(12,177,874)	(166,534,033)	(204,437,254)
ACCUM. DEFERRED TAXES	(122,483,951)	(3,256,157)	(254,697,399)	(95,687,809)	(33,621,425)	(467,518,070)	(562,470,536)
OPERATING LEASES	1,138,283	22,664	4,205,551	1,230,754	317,700	5,006,809	5,066,715
DECOMMISSIONING FUND	70,243,803	1,984,461	105,045,499	47,806,061	19,021,321	248,581,909	319,492,144
CUSTOMER ADVANCES	(1,941,352)	(100,878)	(8,858,012)	(3,752,413)	(1,696,196)	(19,668,272)	(23,654,098)
CUSTOMER DEPOSITS	(351,849)	(18,477)	(1,630,471)	(690,312)	(312,342)	(3,618,504)	(4,349,415)
PROFORMA ADJUSTMENTS	28,397,420	775,078	53,304,189	21,095,894	7,776,847	105,209,441	130,229,037
TOTAL RATE BASE	**563,881,873**	**14,880,066**	**1,181,503,488**	**440,344,517**	**153,486,917**	**2,141,714,639**	**2,571,218,327**
DEVELOPMENT OF RETURN							
BASE REVENUES FROM RATES	58,452,741	3,069,538	270,870,328	114,681,673	51,889,334	601,142,428	722,568,841
PRO FORMA TO BASE REVENUES FROM RATES	(456,828)	(54,668)	8,763,675	(3,471,297)	1,613,889	(18,297,562)	8,537,194
SURCHARGE & OTHER ELECTRIC REVENUES	15,307,364	514,359	39,309,902	15,148,017	6,130,360	77,175,703	102,098,257
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(4,302,104)	(182,825)	(22,282,606)	(7,959,670)	(3,066,291)	(37,903,757)	(49,694,867)
TOTAL OPERATING REVENUES	**69,001,173**	**3,346,404**	**296,661,299**	**118,398,723**	**56,567,292**	**622,116,812**	**783,509,425**
OPERATING EXPENSES							
OPERATION & MAINTENANCE	50,406,025	1,749,933	186,056,505	71,820,650	28,887,368	383,628,315	485,455,100
ADMINISTRATIVE & GENERAL	7,520,578	195,105	18,705,855	6,289,912	2,104,691	29,553,299	34,992,084
DEPRECIATION & AMORT EXPENSE	30,489,298	813,363	63,872,121	23,791,468	8,392,892	116,120,458	140,331,694
OTHER EXPENSE ITEMS	1,306,999	36,924	1,954,544	889,508	353,923	4,625,269	5,944,678
TAXES OTHER THAN INCOME	9,926,018	260,540	21,769,882	7,957,452	2,730,526	38,509,934	45,679,445
PROFORMA ADJUSTMENTS	14,602,470	426,680	17,175,327	5,734,260	3,285,072	34,896,467	56,807,042
INCOME TAX	(10,646,375)	17,732	(4,299,673)	1,425,617	2,685,800	10,068,419	8,346,323
PROFORMA INCOME TAX ADJUSTMENTS	(4,735,333)	(162,873)	(7,475,604)	(4,201,770)	(1,157,242)	(22,318,332)	(23,984,146)
TOTAL OPERATING EXPENSES	**98,869,679**	**3,337,405**	**297,758,959**	**113,707,095**	**47,283,030**	**595,083,829**	**753,572,220**
OPERATING INCOME	**(29,868,506)**	**8,999**	**(1,097,660)**	**4,691,627**	**9,284,262**	**27,032,982**	**29,937,205**
RATE OF RETURN (PRESENT)	**-5.30%**	**0.06%**	**-0.09%**	**1.07%**	**6.05%**	**1.26%**	**1.16%**
INDEX RATE OF RETURN (PRESENT)	**(1.8)**	**0.0**	**(0.0)**	**0.4**	**2.0**	**0.4**	**0.4**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**156,307,569**	**4,544,814**	**403,415,266**	**150,538,939**	**57,001,143**	**768,555,528**	**957,494,075**
% OF TOTAL COST OF SERVICE (PRESENT)	**37.73%**	**68.04%**	**70.44%**	**75.08%**	**95.25%**	**77.06%**	**77.83%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**45.56%**	**81.45%**	**85.12%**	**90.72%**	**115.26%**	**93.12%**	**93.76%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY

Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Combined

	GENERAL SERVICE								
SUMMARY OF RESULTS	**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	$ 12,160,381	$ 5,579,743	$ 8,269,436	$ 30,602,927	$ 77,074,903	$ 53,274,445	$ 512,732,873	$ 795,188,536	$ 914,636,571
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	10,547,706	3,928,185	3,861,969	11,002,846	25,819,833	31,984,511	497,065,199	384,921,647	342,574,123
GENERAL & INTANGIBLE PLANT	2,445,496	1,214,554	1,469,386	4,792,058	11,769,093	8,672,309	134,584,485	146,015,666	140,898,091
LESS: RESERVE FOR DEPRECIATION	(9,260,148)	(4,104,653)	(5,343,821)	(18,588,426)	(46,047,273)	(35,767,346)	(425,372,911)	(518,926,029)	(554,997,907)
MATERIALS, SUPPLIES & PREPAYMENTS	672,766	332,228	434,043	1,617,636	3,951,065	2,866,356	31,302,821	40,606,126	45,650,594
MISCELLANEOUS DEFERRED DEBITS	32,668	17,402	22,573	82,749	201,571	137,750	1,656,371	2,129,779	2,302,222
OTHER DEFERRED CREDITS	(1,550,039)	(756,154)	(1,083,437)	(4,075,355)	(10,148,279)	(6,928,098)	(68,177,331)	(102,640,818)	(118,319,355)
OPEB	602,126	289,809	362,935	1,190,276	2,925,795	2,152,613	31,489,704	36,000,089	34,968,476
WORKING CASH	(111,203)	(37,811)	(46,341)	(138,153)	(349,419)	(361,739)	(4,672,280)	(4,762,256)	(4,709,748)
REGULATORY ASSETS	(1,123,463)	(479,000)	(626,526)	(2,231,525)	(5,518,937)	(4,438,012)	(48,569,682)	(60,059,151)	(66,559,654)
ACCUM. DEFERRED TAXES	(3,020,346)	(1,273,263)	(1,602,860)	(5,447,087)	(13,437,246)	(11,191,450)	(136,604,844)	(156,227,494)	(164,192,403)
OPERATING LEASES	21,251	3,935	2,345	(23,813)	(51,285)	587	1,274,737	631,860	(217,911)
DECOMMISSIONING FUND	1,752,220	816,547	1,204,013	4,484,015	11,264,979	7,747,836	74,342,056	115,275,494	133,048,734
CUSTOMER ADVANCES	(505,673)	(380,282)	(503,612)	(1,333,752)	(3,444,317)	(2,425,196)	(31,915,380)	(40,834,324)	(44,067,912)
CUSTOMER DEPOSITS	(73,495)	(55,316)	(73,245)	(193,861)	(500,661)	(352,540)	(4,641,920)	(5,937,292)	(6,406,665)
PROFORMA ADJUSTMENTS	694,802	317,780	432,230	1,540,647	3,835,158	2,811,882	31,538,290	41,785,723	45,728,213
TOTAL RATE BASE	**13,285,049**	**5,413,704**	**6,779,087**	**23,281,182**	**57,344,978**	**48,183,908**	**596,032,187**	**673,167,555**	**700,335,468**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,958,051	2,979,043	3,944,581	10,440,351	26,962,992	18,985,953	249,989,443	319,751,351	345,029,300
PRO FORMA TO BASE REVENUES FROM RATES	(51,315)	64,393	(248,666)	(524,002)	2,512,750	(240,838)	(3,267,610)	(3,615,921)	(4,925,494)
SURCHARGE & OTHER ELECTRIC REVENUES	563,836	385,003	474,487	1,507,987	3,447,597	2,673,587	30,357,537	43,080,394	45,613,844
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(271,375)	(212,394)	(236,290)	(526,766)	(1,110,721)	(1,162,244)	(16,682,851)	(21,841,740)	(19,790,485)
TOTAL OPERATING REVENUES	**4,199,197**	**3,216,044**	**3,934,112**	**10,897,569**	**31,812,618**	**20,256,458**	**260,396,519**	**337,374,083**	**365,927,166**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,882,082	1,561,672	2,030,311	7,443,789	18,081,818	13,597,127	132,496,905	190,870,127	212,800,995
ADMINISTRATIVE & GENERAL	174,646	83,505	103,866	337,248	828,760	615,551	9,168,890	10,337,005	9,939,782
DEPRECIATION & AMORT EXPENSE	743,035	327,566	418,768	1,436,225	3,546,477	2,804,897	34,534,062	40,787,325	42,860,244
OTHER EXPENSE ITEMS	32,603	15,193	22,403	83,434	209,606	144,162	1,383,264	2,144,901	2,475,610
TAXES OTHER THAN INCOME	245,808	100,119	119,412	395,307	966,477	872,680	11,153,375	11,654,488	11,964,822
PROFORMA ADJUSTMENTS	280,829	71,413	64,546	776,497	3,162,866	1,913,376	7,406,075	13,225,635	20,597,937
INCOME TAX	7,733	273,258	373,265	373,669	1,223,904	518,320	18,088,314	21,260,407	21,834,405
PROFORMA INCOME TAX ADJUSTMENTS	(147,909)	(53,794)	(135,396)	(450,293)	(431,935)	(815,547)	(6,708,113)	(9,520,283)	(11,157,074)
TOTAL OPERATING EXPENSES	**4,218,827**	**2,378,933**	**2,997,175**	**10,395,874**	**27,587,971**	**19,650,566**	**207,522,773**	**280,759,606**	**311,316,723**
OPERATING INCOME	**(19,630)**	**837,112**	**936,938**	**501,695**	**4,224,647**	**605,893**	**52,873,746**	**56,614,477**	**54,610,443**
RATE OF RETURN (PRESENT)	**-0.15%**	**15.46%**	**13.82%**	**2.15%**	**7.37%**	**1.26%**	**8.87%**	**8.41%**	**7.80%**
INDEX RATE OF RETURN (PRESENT)	**(0.0)**	**5.1**	**4.6**	**0.7**	**2.4**	**0.4**	**2.9**	**2.8**	**2.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**5,309,556**	**2,486,970**	**3,148,017**	**11,665,247**	**29,790,044**	**22,935,047**	**237,863,709**	**310,350,664**	**339,869,498**
% OF TOTAL COST OF SERVICE (PRESENT)	**75.64%**	**122.56%**	**117.97%**	**85.46%**	**98.04%**	**84.19%**	**104.59%**	**102.99%**	**100.89%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**91.06%**	**151.44%**	**145.29%**	**105.22%**	**122.58%**	**101.48%**	**128.36%**	**126.06%**	**124.03%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Combined

SUMMARY OF RESULTS	GENERAL SERVICE E-32 (401+ kW)	E-34	E-35	AG-X
DEVELOPMENT OF RATE BASE				
PRODUCTION PLANT IN SERVICE	$ 742,288,876	$ 165,390,653	$ 509,157,006	$ 255,681,872
TRANSMISSION PLANT IN SERVICE	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	249,726,692	43,002,737	114,822,244	63,289,617
GENERAL & INTANGIBLE PLANT	112,720,666	24,744,695	76,652,908	38,087,866
LESS: RESERVE FOR DEPRECIATION	(443,091,368)	(95,361,908)	(289,804,980)	(146,606,994)
MATERIALS, SUPPLIES & PREPAYMENTS	37,759,747	8,395,890	26,129,012	12,990,218
MISCELLANEOUS DEFERRED DEBITS	1,920,565	435,534	1,374,309	675,474
OTHER DEFERRED CREDITS	(97,362,086)	(21,895,160)	(68,060,087)	(33,916,454)
OPEB	28,019,416	6,153,148	19,061,616	9,469,902
WORKING CASH	(3,424,888)	(638,631)	(1,740,757)	(953,668)
REGULATORY ASSETS	(53,150,663)	(11,312,539)	(34,111,854)	(17,366,848)
ACCUM. DEFERRED TAXES	(129,472,511)	(27,162,737)	(81,388,376)	(41,560,163)
OPERATING LEASES	(453,703)	(150,147)	(558,969)	(249,997)
DECOMMISSIONING FUND	108,391,564	24,219,412	74,749,071	37,464,644
CUSTOMER ADVANCES	(33,111,143)	(4,891,691)	(71,283,271)	(10,302,194)
CUSTOMER DEPOSITS	(4,812,982)	(710,299)	(2,857,985)	(1,497,169)
PROFORMA ADJUSTMENTS	36,877,857	8,090,630	24,817,250	12,471,504
TOTAL RATE BASE	**552,826,039**	**118,309,588**	**296,957,137**	**177,677,609**
DEVELOPMENT OF RETURN				
BASE REVENUES FROM RATES	259,201,950	38,252,968	153,916,079	80,629,651
PRO FORMA TO BASE REVENUES FROM RATES	304,925	2,210,724	(5,836,221)	(1,342,165)
SURCHARGE & OTHER ELECTRIC REVENUES	33,914,431	7,477,244	24,217,213	5,158,094
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(11,674,669)	(2,299,744)	(7,790,126)	2,809,278
TOTAL OPERATING REVENUES	**281,746,637**	**45,641,193**	**164,506,945**	**87,254,858**
OPERATING EXPENSES				
OPERATION & MAINTENANCE	174,962,433	40,524,545	127,343,842	68,489,878
ADMINISTRATIVE & GENERAL	7,938,614	1,737,196	5,372,885	2,671,500
DEPRECIATION & AMORT EXPENSE	34,114,284	7,299,435	22,144,386	11,209,505
OTHER EXPENSE ITEMS	2,016,825	450,648	1,390,850	697,101
TAXES OTHER THAN INCOME	9,318,267	1,895,042	5,587,087	2,884,186
PROFORMA ADJUSTMENTS	19,572,255	6,536,884	13,110,803	4,742,134
INCOME TAX	11,657,985	(2,451,006)	1,523,237	(1,439,545)
PROFORMA INCOME TAX ADJUSTMENTS	(7,616,253)	(1,632,430)	(6,595,338)	(801,544)
TOTAL OPERATING EXPENSES	**251,964,411**	**54,360,314**	**169,877,751**	**88,453,215**
OPERATING INCOME	**29,782,226**	**(8,719,121)**	**(5,370,807)**	**(1,198,358)**
RATE OF RETURN (PRESENT)	**5.39%**	**-7.37%**	**-1.81%**	**-0.67%**
INDEX RATE OF RETURN (PRESENT)	**1.8**	**(2.4)**	**(0.6)**	**(0.2)**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**277,152,418**	**64,408,170**	**186,169,924**	**99,360,135**
% OF TOTAL COST OF SERVICE (PRESENT)	**92.91%**	**62.61%**	**78.82%**	**78.05%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**117.75%**	**92.28%**	**94.31%**	**79.15%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Delivered Load

				RETAIL					
SUMMARY OF RESULTS	**ELECTRIC TOTAL**	**ALL OTHER**	**ACC JURISDICTION**	**RESIDENTIAL**	**GENERAL SERVICE**	**E-221 NonAG**	**E-221 AG**	**Street Lighting**	**Dusk to Dawn**
DEVELOPMENT OF RATE BASE									
PRODUCTION PLANT IN SERVICE	$ 9,832,767,730	$ 12,364,736	$ 9,820,402,994	$ 5,521,584,142	$ 4,202,486,962	$ 74,902,778	$ -	$ 18,298,275	$ 3,130,837
TRANSMISSION PLANT IN SERVICE	3,414,532,481	3,414,532,481	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	7,763,311,806	47,825	7,763,263,981	5,719,435,080	1,832,558,568	40,475,684	-	107,962,247	62,832,403
GENERAL & INTANGIBLE PLANT	2,381,362,366	201,428,361	2,179,934,005	1,435,352,192	721,558,037	13,717,912	-	5,257,062	4,048,802
LESS: RESERVE FOR DEPRECIATION	(8,525,604,548)	(1,097,524,168)	(7,428,080,380)	(4,650,595,293)	(2,666,669,062)	(50,390,115)	-	(39,862,397)	(20,563,514)
MATERIALS, SUPPLIES & PREPAYMENTS	611,970,887	60,482,273	551,488,614	324,375,100	218,469,492	4,329,734	-	2,987,944	1,326,344
MISCELLANEOUS DEFERRED DEBITS	30,089,000	1,720,840	28,368,160	16,757,262	11,267,525	223,564	-	83,378	36,430
OTHER DEFERRED CREDITS	(1,293,452,000)	(17,036,265)	(1,276,415,735)	(712,347,034)	(550,097,775)	(10,193,799)	-	(3,051,368)	(725,761)
OPEB	568,515,119	50,051,519	518,463,600	335,891,056	177,035,092	3,391,955	-	1,282,391	863,107
WORKING CASH	(105,488,059)	(25,065,875)	(80,422,184)	(56,126,168)	(22,660,505)	(410,199)	-	(780,305)	(445,007)
REGULATORY ASSETS	(824,250,000)	41,483,766	(865,733,766)	(535,794,821)	(314,528,745)	(6,020,048)	-	(6,300,972)	(3,089,181)
ACCUM. DEFERRED TAXES	(2,354,271,572)	(1,458,100)	(2,352,813,472)	(1,516,965,747)	(794,735,268)	(15,300,861)	-	(16,845,061)	(8,966,536)
OPERATING LEASES	22,468,854	5,215,753	17,253,101	16,988,465	232,254	(25,403)	-	(7,784)	65,570
DECOMMISSIONING FUND	1,422,493,893	1,706,993	1,420,786,900	794,349,143	612,181,027	11,005,649	-	2,774,412	476,669
CUSTOMER ADVANCES	(336,198,398)	(30,943,932)	(305,254,466)	(59,660,044)	(245,009,669)	(12,453)	-	(572,001)	(299)
CUSTOMER DEPOSITS	(40,062,749)	-	(40,062,749)	(10,971,370)	(28,113,431)	(604,946)	-	(373,003)	-
PROFORMA ADJUSTMENTS	578,176,449	13,488,880	564,687,569	340,656,005	216,923,057	4,027,681	-	2,107,725	973,101
TOTAL RATE BASE	**13,146,361,258**	**2,630,495,087**	**10,515,866,171**	**6,962,927,970**	**3,370,897,558**	**69,117,133**	**-**	**72,960,544**	**39,962,966**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,468,594,702	70,581,514	3,398,013,188	1,822,674,883	1,514,041,713	32,579,215	-	20,087,962	8,629,415
PRO FORMA TO BASE REVENUES FROM RATES	(21,200,909)	-	(21,200,909)	(3,365,597)	(14,959,440)	(2,243,274)	-	(790,435)	157,837
SURCHARGE & OTHER ELECTRIC REVENUES	513,230,298	51,966,910	461,263,388	252,347,800	202,112,352	4,971,078	-	1,455,998	376,160
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(209,593,326)	(181,152)	(209,412,174)	(125,386,522)	(80,795,562)	(2,446,406)	-	(569,097)	(214,587)
TOTAL OPERATING REVENUES	**3,751,030,765**	**122,367,272**	**3,628,663,493**	**1,946,270,563**	**1,620,399,063**	**32,860,613**	**-**	**20,184,428**	**8,948,826**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,021,289,826	(210,113,145)	2,231,402,972	1,237,621,354	964,114,018	21,429,976	-	6,394,373	1,843,251
ADMINISTRATIVE & GENERAL	169,603,050	19,345,717	150,257,333	98,091,050	50,547,234	968,902	-	385,233	264,914
DEPRECIATION & AMORT EXPENSE	677,267,319	82,201,254	595,066,064	377,999,320	207,884,765	3,971,213	-	3,403,723	1,807,044
OTHER EXPENSE ITEMS	26,436,176	2	26,436,174	14,780,161	11,390,738	204,781	-	51,625	8,870
TAXES OTHER THAN INCOME	227,125,941	39,350,683	187,775,259	125,142,412	58,799,043	1,167,153	-	1,723,250	943,400
PROFORMA ADJUSTMENTS	231,114,792	4,280,481	226,834,312	128,346,672	95,907,799	1,477,139	-	827,441	275,261
INCOME TAX	115,485,000	30,346,870	85,138,130	2,501,082	78,239,201	1,897,174	-	1,789,433	711,239
PROFORMA INCOME TAX ADJUSTMENTS	(113,749,921)	(1,563,439)	(112,186,482)	(62,909,052)	(47,159,522)	(1,519,689)	-	(524,885)	(73,334)
TOTAL OPERATING EXPENSES	**3,354,572,184**	**(36,151,578)**	**3,390,723,762**	**1,921,572,999**	**1,419,723,277**	**29,596,651**	**-**	**14,050,193**	**5,780,643**
OPERATING INCOME	**396,458,581**	**158,518,851**	**237,939,731**	**24,697,565**	**200,675,786**	**3,263,962**	**0**	**6,134,235**	**3,168,182**
RATE OF RETURN (PRESENT)	**3.02%**	**6.03%**	**2.26%**	**0.35%**	**5.95%**	**4.72%**	**0.00%**	**8.41%**	**7.93%**
INDEX RATE OF RETURN (PRESENT)	**1.0**	**2.0**	**0.8**	**0.1**	**2.0**	**1.6**	**-**	**2.8**	**2.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**4,259,739,214**	**110,774,692**	**4,148,964,522**	**2,507,485,245**	**1,580,985,055**	**33,152,163**	**0**	**18,655,191**	**8,686,868**
% OF TOTAL COST OF SERVICE (PRESENT)	**81.78%**	**63.72%**	**82.26%**	**73.82%**	**95.05%**	**94.50%**	**0.00%**	**103.04%**	**101.06%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**99.06%**	**63.72%**	**100.00%**	**89.09%**	**116.59%**	**116.75%**		**122.73%**	**116.85%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Delivered Load

	RESIDENTIAL								
SUMMARY OF RESULTS	**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	$ 348,065,578	$ 10,945,080	$ 140,579,287	$ 61,736,033	$ 750,935,014	$ 343,052,008	$ 136,069,080	$ 1,546,433,722	$ 2,183,768,340
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	351,606,923	9,356,015	190,179,895	70,245,163	1,126,978,503	379,712,656	121,111,058	1,538,043,823	1,932,201,045
GENERAL & INTANGIBLE PLANT	88,586,689	2,391,266	45,805,712	17,356,656	281,583,031	93,737,361	31,179,718	379,503,782	495,207,979
LESS: RESERVE FOR DEPRECIATION	(289,412,899)	(8,415,583)	(136,046,970)	(54,589,997)	(778,347,284)	(297,759,174)	(106,788,130)	(1,271,061,473)	(1,708,173,783)
MATERIALS, SUPPLIES & PREPAYMENTS	19,977,652	598,345	9,316,222	3,867,851	52,324,332	20,238,019	7,569,975	88,598,259	121,884,445
MISCELLANEOUS DEFERRED DEBITS	1,027,393	29,865	499,207	202,566	2,924,874	1,051,144	382,749	4,495,475	6,143,989
OTHER DEFERRED CREDITS	(44,486,220)	(1,390,155)	(18,683,566)	(8,151,234)	(101,200,903)	(43,963,656)	(17,366,355)	(197,763,242)	(279,341,704)
OPEB	20,744,109	567,842	10,553,014	4,042,771	64,283,445	21,832,065	7,372,854	89,229,563	117,265,393
WORKING CASH	(3,528,277)	(99,527)	(1,686,662)	(649,158)	(9,628,155)	(3,709,013)	(1,261,031)	(15,493,224)	(20,071,121)
REGULATORY ASSETS	(33,367,305)	(993,555)	(15,272,049)	(6,251,783)	(84,594,948)	(34,052,259)	(12,499,298)	(148,158,466)	(200,605,159)
ACCUM. DEFERRED TAXES	(94,270,881)	(2,709,479)	(45,243,342)	(17,904,320)	(259,243,320)	(97,788,265)	(34,433,858)	(414,608,072)	(550,764,209)
OPERATING LEASES	1,078,748	23,411	626,946	200,078	4,223,959	1,241,470	321,134	4,369,409	4,903,311
DECOMMISSIONING FUND	49,981,383	1,574,429	20,253,727	8,916,535	108,122,733	49,206,576	19,578,542	222,260,149	314,455,070
CUSTOMER ADVANCES	(1,928,648)	(100,621)	(1,861,534)	(800,657)	(8,859,941)	(3,753,291)	(1,696,546)	(17,802,934)	(22,855,873)
CUSTOMER DEPOSITS	(351,849)	(18,477)	(342,859)	(147,442)	(1,630,471)	(690,312)	(312,342)	(3,275,644)	(4,201,973)
PROFORMA ADJUSTMENTS	21,250,522	631,376	9,618,834	3,953,177	54,407,289	21,599,407	7,975,577	93,518,547	127,701,276
TOTAL RATE BASE	**434,972,919**	**12,390,233**	**208,295,861**	**82,026,239**	**1,202,278,157**	**449,954,735**	**157,203,128**	**1,898,289,672**	**2,517,517,025**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	58,452,741	3,069,538	56,959,275	24,494,557	270,870,328	114,681,673	51,889,334	544,183,153	698,074,284
PRO FORMA TO BASE REVENUES FROM RATES	(456,828)	(54,668)	(1,257,216)	(494,918)	8,763,675	(3,471,297)	1,613,889	(17,040,346)	9,032,112
SURCHARGE & OTHER ELECTRIC REVENUES	11,844,763	429,336	7,022,580	3,196,258	39,778,749	15,345,946	6,214,637	69,089,059	99,426,471
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(4,296,386)	(182,683)	(3,706,507)	(1,674,857)	(22,283,362)	(7,959,984)	(3,066,425)	(34,195,505)	(48,020,813)
TOTAL OPERATING REVENUES	**65,544,291**	**3,261,523**	**59,018,132**	**25,521,040**	**297,129,390**	**118,596,338**	**56,651,434**	**562,036,362**	**758,512,053**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	87,941,091	2,574,744	82,300,484	32,395,231	179,526,824	68,654,486	27,316,415	311,251,523	445,660,557
ADMINISTRATIVE & GENERAL	6,057,758	164,972	3,098,984	1,181,854	18,928,342	6,390,737	2,144,751	26,029,608	34,094,045
DEPRECIATION & AMORT EXPENSE	23,480,639	674,724	11,254,945	4,465,553	64,979,736	24,299,827	8,591,322	102,910,744	137,341,831
OTHER EXPENSE ITEMS	929,984	29,295	376,854	165,907	2,011,801	915,566	364,291	4,135,509	5,850,953
TAXES OTHER THAN INCOME	7,753,267	219,092	3,839,090	1,493,079	22,127,749	8,123,598	2,794,146	34,104,891	44,687,500
PROFORMA ADJUSTMENTS	9,595,986	309,606	2,890,090	1,425,556	17,894,006	6,044,236	3,414,114	30,525,355	56,247,722
INCOME TAX	(17,066,801)	(134,184)	(10,668,554)	(3,583,631)	(3,160,615)	1,985,343	2,989,202	19,045,939	13,094,384
PROFORMA INCOME TAX ADJUSTMENTS	(3,507,200)	(134,087)	(1,921,111)	(880,984)	(7,651,530)	(4,277,561)	(1,188,838)	(20,033,152)	(23,314,588)
TOTAL OPERATING EXPENSES	**115,184,724**	**3,704,160**	**91,170,783**	**36,662,564**	**294,656,311**	**112,136,231**	**46,425,403**	**507,970,417**	**713,662,405**
OPERATING INCOME	**(49,640,433)**	**(442,637)**	**(32,152,651)**	**(11,141,524)**	**2,473,079**	**6,460,107**	**10,226,031**	**54,065,945**	**44,849,648**
RATE OF RETURN (PRESENT)	**-11.41%**	**-3.57%**	**-15.44%**	**-13.58%**	**0.21%**	**1.44%**	**6.50%**	**2.85%**	**1.78%**
INDEX RATE OF RETURN (PRESENT)	**(3.8)**	**(1.2)**	**(5.1)**	**(4.5)**	**0.1**	**0.5**	**2.2**	**0.9**	**0.6**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**169,356,549**	**4,889,790**	**120,221,742**	**47,379,749**	**400,797,662**	**149,171,911**	**56,128,090**	**651,529,864**	**908,009,888**
% OF TOTAL COST OF SERVICE (PRESENT)	**34.82%**	**63.24%**	**47.04%**	**51.92%**	**70.90%**	**75.77%**	**96.73%**	**82.22%**	**79.36%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**42.05%**	**75.71%**	**56.41%**	**64.23%**	**85.67%**	**91.55%**	**117.05%**	**99.44%**	**95.52%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Delivered Load

	GENERAL SERVICE								
SUMMARY OF RESULTS	**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	$ 12,518,695	$ 5,744,476	$ 8,513,420	$ 31,506,572	$ 79,350,051	$ 54,846,047	$ 527,852,748	$ 818,637,166	$ 941,619,232
TRANSMISSION PLANT IN SERVICE	-	-	-	-	-	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	10,872,863	4,005,357	3,977,722	11,378,234	26,737,199	33,061,852	504,689,085	396,096,313	354,053,833
GENERAL & INTANGIBLE PLANT	2,500,600	1,239,125	1,505,128	4,926,093	12,102,848	8,911,504	136,777,449	149,396,876	144,799,265
LESS: RESERVE FOR DEPRECIATION	(9,525,163)	(4,207,993)	(5,496,415)	(19,142,658)	(47,431,000)	(36,842,017)	(434,911,496)	(533,534,718)	(571,486,450)
MATERIALS, SUPPLIES & PREPAYMENTS	691,461	340,537	445,897	1,662,807	4,062,131	2,947,813	32,021,164	41,707,340	46,929,229
MISCELLANEOUS DEFERRED DEBITS	33,446	17,802	23,136	84,961	206,999	141,421	1,689,891	2,181,517	2,363,635
OTHER DEFERRED CREDITS	(1,593,939)	(777,283)	(1,114,160)	(4,191,628)	(10,438,312)	(7,126,227)	(70,053,616)	(105,546,787)	(121,701,753)
OPEB	615,833	295,919	371,823	1,223,608	3,008,788	2,212,106	32,035,007	36,840,835	35,938,512
WORKING CASH	(114,858)	(38,805)	(47,903)	(143,186)	(362,249)	(374,320)	(4,776,316)	(4,919,134)	(4,874,387)
REGULATORY ASSETS	(1,158,209)	(491,763)	(645,391)	(2,299,351)	(5,687,874)	(4,575,113)	(49,754,724)	(61,865,672)	(68,580,967)
ACCUM. DEFERRED TAXES	(3,109,679)	(1,304,797)	(1,649,665)	(5,613,708)	(13,852,613)	(11,537,437)	(139,561,165)	(160,724,877)	(169,189,144)
OPERATING LEASES	21,627	3,905	2,373	(24,078)	(51,641)	1,129	1,280,378	640,382	(214,478)
DECOMMISSIONING FUND	1,803,549	840,462	1,239,278	4,615,342	11,594,915	7,974,774	76,519,660	118,652,116	136,945,791
CUSTOMER ADVANCES	(505,705)	(380,297)	(503,634)	(1,333,834)	(3,444,524)	(2,425,338)	(31,916,745)	(40,836,441)	(44,070,356)
CUSTOMER DEPOSITS	(73,495)	(55,316)	(73,245)	(193,861)	(500,661)	(352,540)	(4,641,920)	(5,937,292)	(6,406,665)
PROFORMA ADJUSTMENTS	714,409	326,116	444,503	1,585,891	3,948,342	2,894,768	32,299,647	42,958,567	47,068,130
TOTAL RATE BASE	**13,691,437**	**5,557,447**	**6,992,868**	**24,041,201**	**59,242,398**	**49,758,421**	**609,549,046**	**693,746,190**	**723,193,429**
DEVELOPMENT OF RETURN									
BASE REVENUES FROM RATES	3,958,051	2,979,043	3,944,581	10,440,351	26,962,992	18,985,953	249,989,443	319,751,351	345,029,300
PRO FORMA TO BASE REVENUES FROM RATES	(51,315)	64,393	(248,666)	(524,002)	2,512,750	(240,838)	(3,267,610)	(3,615,921)	(4,925,494)
SURCHARGE & OTHER ELECTRIC REVENUES	571,896	389,742	481,026	1,534,911	3,511,729	2,715,140	30,733,326	43,663,608	46,322,694
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(271,388)	(212,402)	(236,301)	(526,812)	(1,110,829)	(1,162,312)	(16,683,471)	(21,842,697)	(19,791,665)
TOTAL OPERATING REVENUES	**4,207,244**	**3,220,775**	**3,940,641**	**10,924,448**	**31,876,642**	**20,297,943**	**260,771,689**	**337,956,341**	**366,634,835**
OPERATING EXPENSES									
OPERATION & MAINTENANCE	2,788,924	1,519,209	1,969,197	7,218,618	17,519,102	13,205,301	128,467,846	185,334,929	206,104,906
ADMINISTRATIVE & GENERAL	178,607	85,244	106,400	346,719	852,351	632,606	9,324,670	10,577,036	10,216,063
DEPRECIATION & AMORT EXPENSE	764,015	335,572	430,579	1,479,019	3,653,160	2,889,152	35,273,043	41,916,956	44,131,820
OTHER EXPENSE ITEMS	33,558	15,638	23,059	85,877	215,745	148,385	1,423,782	2,207,729	2,548,121
TAXES OTHER THAN INCOME	253,246	102,498	122,948	407,662	997,139	900,295	11,378,687	11,994,402	12,336,408
PROFORMA ADJUSTMENTS	293,359	78,156	73,974	814,346	3,254,005	1,974,445	7,957,978	14,079,668	21,620,414
INCOME TAX	21,382	280,715	383,765	413,572	1,323,002	580,414	18,786,568	22,176,915	22,997,222
PROFORMA INCOME TAX ADJUSTMENTS	(150,963)	(55,452)	(137,713)	(459,610)	(454,366)	(830,508)	(6,843,626)	(9,730,064)	(11,408,524)
TOTAL OPERATING EXPENSES	**4,182,127**	**2,361,580**	**2,972,209**	**10,306,203**	**27,360,138**	**19,500,089**	**205,768,949**	**278,557,571**	**308,546,430**
OPERATING INCOME	**25,117**	**859,195**	**968,431**	**618,244**	**4,516,504**	**797,854**	**55,002,740**	**59,398,771**	**58,088,406**
RATE OF RETURN (PRESENT)	**0.18%**	**15.46%**	**13.85%**	**2.57%**	**7.62%**	**1.60%**	**9.02%**	**8.56%**	**8.03%**
INDEX RATE OF RETURN (PRESENT)	**0.1**	**5.1**	**4.6**	**0.9**	**2.5**	**0.5**	**3.0**	**2.8**	**2.7**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**5,291,869**	**2,472,383**	**3,128,118**	**11,588,427**	**29,597,048**	**22,841,828**	**236,421,068**	**308,764,891**	**337,594,283**
% OF TOTAL COST OF SERVICE (PRESENT)	**75.89%**	**123.29%**	**118.72%**	**86.03%**	**98.68%**	**84.54%**	**105.23%**	**103.52%**	**101.57%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**91.36%**	**152.33%**	**146.21%**	**105.92%**	**123.38%**	**101.90%**	**129.14%**	**126.71%**	**124.87%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Summary of 2021_2022 Test Year Adjusted Cost of Service Study - Delivered Load

SUMMARY OF RESULTS	GENERAL SERVICE E-32 (401+ kW)	E-34	E-35	AG-X
DEVELOPMENT OF RATE BASE				
PRODUCTION PLANT IN SERVICE	$ 764,197,724	$ 170,273,959	$ 524,195,173	$ 263,231,701
TRANSMISSION PLANT IN SERVICE	-	-	-	-
DISTRIBUTION PLANT IN SERVICE	258,545,634	44,610,024	119,127,471	65,402,983
GENERAL & INTANGIBLE PLANT	115,922,665	25,455,798	78,844,529	39,176,156
LESS: RESERVE FOR DEPRECIATION	(456,397,919)	(98,237,165)	(298,505,388)	(150,950,681)
MATERIALS, SUPPLIES & PREPAYMENTS	38,821,360	8,631,592	26,858,292	13,349,871
MISCELLANEOUS DEFERRED DEBITS	1,972,341	447,320	1,411,362	693,693
OTHER DEFERRED CREDITS	(100,145,706)	(22,520,899)	(70,002,710)	(34,884,754)
OPEB	28,815,633	6,329,967	19,606,567	9,740,493
WORKING CASH	(3,549,596)	(662,943)	(1,808,524)	(988,282)
REGULATORY ASSETS	(54,775,059)	(11,658,758)	(35,150,775)	(17,885,091)
ACCUM. DEFERRED TAXES	(133,468,770)	(28,006,352)	(83,902,500)	(42,814,560)
OPERATING LEASES	(456,015)	(151,726)	(566,533)	(253,069)
DECOMMISSIONING FUND	111,566,245	24,928,749	76,938,246	38,561,898
CUSTOMER ADVANCES	(33,113,133)	(4,892,136)	(71,284,644)	(10,302,882)
CUSTOMER DEPOSITS	(4,812,982)	(710,299)	(2,857,985)	(1,497,169)
PROFORMA ADJUSTMENTS	37,966,117	8,329,959	25,549,353	12,837,256
TOTAL RATE BASE	**571,088,538**	**122,167,087**	**308,451,933**	**183,417,563**
DEVELOPMENT OF RETURN				
BASE REVENUES FROM RATES	259,201,950	38,252,968	153,916,079	80,629,651
PRO FORMA TO BASE REVENUES FROM RATES	304,925	2,210,724	(5,836,221)	(1,342,165)
SURCHARGE & OTHER ELECTRIC REVENUES	34,524,782	7,619,272	24,667,689	5,376,537
PRO FORMA SURCHARGE & OTHER ELECTRIC REVENUES	(11,675,699)	(2,299,985)	(7,790,902)	2,808,901
TOTAL OPERATING REVENUES	**282,355,958**	**45,782,979**	**164,956,645**	**87,472,924**
OPERATING EXPENSES				
OPERATION & MAINTENANCE	169,467,819	39,302,123	123,619,687	67,596,357
ADMINISTRATIVE & GENERAL	8,165,000	1,787,332	5,527,109	2,748,099
DEPRECIATION & AMORT EXPENSE	35,139,893	7,520,015	22,810,092	11,541,449
OTHER EXPENSE ITEMS	2,075,896	463,846	1,431,584	717,517
TAXES OTHER THAN INCOME	9,613,186	1,955,628	5,764,492	2,972,454
PROFORMA ADJUSTMENTS	20,441,298	6,736,393	13,738,860	4,844,902
INCOME TAX	12,630,048	(2,228,439)	2,210,521	(1,336,485)
PROFORMA INCOME TAX ADJUSTMENTS	(7,830,124)	(1,681,593)	(6,750,219)	(826,761)
TOTAL OPERATING EXPENSES	**249,703,015**	**53,855,307**	**168,352,126**	**88,257,532**
OPERATING INCOME	**32,652,942**	**(8,072,328)**	**(3,395,481)**	**(784,608)**
RATE OF RETURN (PRESENT)	**5.72%**	**-6.61%**	**-1.10%**	**-0.43%**
INDEX RATE OF RETURN (PRESENT)	**1.9**	**(2.2)**	**(0.4)**	**(0.1)**
TOTAL REVENUE REQUIREMENT (Including Fair Value Increment)	**275,212,402**	**63,944,565**	**184,724,784**	**99,403,388**
% OF TOTAL COST OF SERVICE (PRESENT)	**93.57%**	**63.07%**	**79.43%**	**78.02%**
% OF TOTAL COST OF SERVICE (PROPOSED @ Class Specific)	**118.58%**	**92.95%**	**95.05%**	**79.11%**

Note: % of Cost to Serve does not reflect all costs associated with exported energy

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

SUMMARY OF RESULTS	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
COS - Site Load	197,460,118	5,518,162	100,219,061	41,445,881
Solar Credits	41,152,549	973,348	(12,039,099)	(2,305,834)
Net COS	156,307,569	4,544,814	112,258,160	43,751,715
Revenue Deficiency	97,335,412	1,452,646	55,707,529	19,153,568
% COS Recovered	**37.7%**	**68.0%**	**50.4%**	**56.2%**

From COSS:				
BASE REVENUES FROM RATES	58,452,741	3,069,538	56,959,275	24,494,557
PRO FORMA TO BASE REVENUES FROM RATES	(456,828)	(54,668)	(1,257,217)	(494,918)
Credit for Adjustor Transfers				
DSMAC Transfer	605,657	28,629	523,755	242,769
EIS Transfer	161,153	7,667	140,842	65,040
LFCR	1,561,802	98,476	1,077,443	713,556
TEAM	(1,352,368)	(57,474)	(893,467)	(422,857)
Revenues	58,972,157	3,092,168	56,550,631	24,598,147

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Rates				
Weighted Non-Solar Residential ROR	1.41%	1.41%	1.41%	1.41%
Long Term Debt Rate	1.85%	1.85%	1.85%	1.85%
Composite Tax Rate	24.72%	24.72%	24.72%	24.72%
Total Rate Base				
Production				
Demand Production	298,016,226	8,419,272	138,510,454	59,339,658
Demand Production (Step-Up Txf Adj)	4,588,528	129,631	2,132,632	913,647
Total Production	302,604,754	8,548,903	140,643,086	60,253,305
Transmission - Ancillary Services	-	-	-	-
Distribution				
Demand - Substation	35,745,588	973,113	14,992,162	6,637,949
Demand - OH Primary	32,378,255	798,995	16,442,792	6,329,265
Demand - OH Secondary	16,913,739	450,375	10,998,637	3,975,784
Demand - UG Primary	90,689,519	2,237,893	46,054,601	17,727,552
Demand - UG Secondary	15,335,459	408,341	9,972,173	3,604,722
Demand - OH Transformer	7,049,566	172,212	4,577,395	1,594,524
Demand - UG Transformer	26,987,495	656,011	17,521,993	6,091,091
Services - OH	3,352,407	69,227	2,171,301	707,179
Services - UG	12,074,515	249,334	7,820,358	2,547,030
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	240,526,543	6,015,502	130,551,411	49,215,095
Return on Rate Base				
Production				
Demand Production	4,192,771	118,450	1,948,694	834,846
Demand Production (Step-Up Txf Adj)	64,556	1,824	30,004	12,854
Total Production	4,257,326	120,274	1,978,698	847,700
Transmission - Ancillary Services	-	-	-	-
Distribution				
Demand - Substation	502,902	13,691	210,924	93,389
Demand - OH Primary	455,528	11,241	231,333	89,046
Demand - OH Secondary	237,958	6,336	154,739	55,935
Demand - UG Primary	1,275,905	31,485	647,939	249,408
Demand - UG Secondary	215,754	5,745	140,298	50,715
Demand - OH Transformer	99,180	2,423	64,399	22,433
Demand - UG Transformer	379,685	9,229	246,516	85,695
Services - OH	47,165	974	30,548	9,949
Services - UG	169,876	3,508	110,024	35,834
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	3,383,952	84,632	1,836,719	692,404

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Taxes				
Production				
Demand Production	(433,622)	(12,250)	(201,537)	(86,341)
Demand Production (Step-Up Txf Adj)	(6,676)	(189)	(3,103)	(1,329)
Total Production	(440,298)	(12,439)	(204,640)	(87,670)
Transmission - Ancillary Services	-	-	-	-
Distribution				
Demand - Substation	(52,011)	(1,416)	(21,814)	(9,658)
Demand - OH Primary	(47,111)	(1,163)	(23,925)	(9,209)
Demand - OH Secondary	(24,610)	(655)	(16,003)	(5,785)
Demand - UG Primary	(131,956)	(3,256)	(67,011)	(25,794)
Demand - UG Secondary	(22,314)	(594)	(14,510)	(5,245)
Demand - OH Transformer	(10,257)	(251)	(6,660)	(2,320)
Demand - UG Transformer	(39,268)	(955)	(25,495)	(8,863)
Services - OH	(4,878)	(101)	(3,159)	(1,029)
Services - UG	(17,569)	(363)	(11,379)	(3,706)
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	(349,973)	(8,753)	(189,956)	(71,609)
Expenses Excluding Income Taxes				
Production				
Demand Production	47,217,912	1,327,222	22,072,773	9,418,298
Demand Production (Step-Up Txf Adj)	381,178	10,769	177,162	75,899
Total Production	47,599,090	1,337,991	22,249,935	9,494,196
Transmission - Ancillary Services	16,156,943	430,852	7,367,571	3,015,966
Distribution				
Demand - Substation	3,425,111	94,192	1,447,108	642,211
Demand - OH Primary	3,688,662	91,951	1,887,014	728,048
Demand - OH Secondary	1,927,257	51,841	1,262,476	457,419
Demand - UG Primary	7,724,695	192,561	3,951,732	1,524,657
Demand - UG Secondary	1,266,689	34,072	829,761	300,638
Demand - OH Transformer	565,279	13,950	369,750	129,101
Demand - UG Transformer	2,164,028	53,139	1,415,381	493,167
Services - OH	383,711	8,004	250,352	81,727
Services - UG	1,002,851	20,920	654,310	213,599
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	22,148,283	560,630	12,067,884	4,570,567

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Revenue Credits				
Production				
Demand Production	223,112	6,677	105,768	47,364
Demand Production (Step-Up Txf Adj)	-	-	-	-
Total Production	223,112	6,677	105,768	47,364
Transmission - Ancillary Services	-	-	-	-
Distribution				
Demand - Substation	904,775	24,882	382,267	169,646
Demand - OH Primary	991,565	24,718	507,256	195,710
Demand - OH Secondary	439,863	11,832	288,138	104,398
Demand - UG Primary	1,997,376	49,791	1,021,800	394,231
Demand - UG Secondary	337,753	9,085	221,250	80,163
Demand - OH Transformer	158,862	3,920	103,912	36,282
Demand - UG Transformer	608,165	14,934	397,770	138,597
Services - OH	87,404	1,823	57,027	18,616
Services - UG	266,644	5,562	173,972	56,793
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	5,792,408	146,547	3,153,392	1,194,435
Revenue Requirement				
Production				
Demand Production	50,753,949	1,426,745	23,714,163	10,119,439
Demand Production (Step-Up Txf Adj)	439,058	12,404	204,063	87,423
Total Production	51,193,007	1,439,149	23,918,226	10,206,862
Transmission - Ancillary Services	16,156,943	430,852	7,367,571	3,015,966
Distribution				
Demand - Substation	2,971,227	81,585	1,253,950	556,295
Demand - OH Primary	3,105,514	77,312	1,587,165	612,175
Demand - OH Secondary	1,700,742	45,690	1,113,073	403,171
Demand - UG Primary	6,871,268	170,999	3,510,860	1,354,040
Demand - UG Secondary	1,122,375	30,138	734,300	265,945
Demand - OH Transformer	495,339	12,202	323,577	112,932
Demand - UG Transformer	1,896,281	46,480	1,238,632	431,403
Services - OH	338,594	7,054	220,714	72,031
Services - UG	888,514	18,502	578,984	188,934
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	19,389,855	489,963	10,561,255	3,996,926
Percentage Difference in Delivery vs. Site				
Production Demand Credit (4CP & NCP)	21.54%	18.08%	28.32%	26.43%
Transmission Credit (4CP)	30.16%	25.30%	41.82%	39.92%
Distribution Substation Credit (NCP)	12.92%	10.86%	14.82%	12.93%
Distribution Primary Credit (NCP)	12.92%	10.86%	14.82%	12.93%
Distribution Secondary Credit (Ind Max)	11.92%	9.31%	14.04%	12.82%

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Credits
Site Load - Solar Table

	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Solar Demand Credit				
Production				
Demand Production	10,931,371	257,918	6,715,542	2,674,292
Demand Production (Step-Up Txf Adj)	94,564	2,242	57,788	23,104
Total Production	11,025,935	260,160	6,773,330	2,697,396
Transmission - Ancillary Services (Before Adj.)	4,873,036	108,990	3,080,796	1,204,080
Transmission Cost Before Reallocation	5,408,118	248,522	4,574,090	2,132,554
Adjustment to Transmission Credit	(10,748,825)	(182,330)	(2,793,481)	(883,413)
Transmission - Ancillary Services (Incl. Adj.)	(5,875,789)	(73,340)	287,315	320,667
Distribution				
Demand - Substation	383,743	8,859	185,858	71,935
Demand - OH Primary	401,087	8,395	235,246	79,161
Demand - OH Secondary	202,695	4,256	156,308	51,667
Demand - UG Primary	887,446	18,568	520,371	175,091
Demand - UG Secondary	133,765	2,807	103,117	34,081
Demand - OH Transformer	59,035	1,136	45,440	14,472
Demand - UG Transformer	225,999	4,329	173,941	55,285
Services - OH	40,354	657	30,995	9,231
Services - UG	105,893	1,723	81,306	24,212
Dusk to Dawn	-	-	-	-
Street Lighting	-	-	-	-
Total Distribution	2,440,015	50,730	1,532,582	515,135
Value of Solar Production Less RCP	**33,562,387**	**735,797**	**(20,632,327)**	**(5,839,032)**
Total	**41,152,549**	**973,348**	**(12,039,099)**	**(2,305,834)**

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Costs
Delivered Load (Bottom-Up)

SUMMARY OF RESULTS	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
COS - Delivered Load	149,711,594	4,491,789	71,735,442	29,660,184
Solar Costs	19,644,955	398,001	48,486,299	17,719,564
Net COS	169,356,549	4,889,790	120,221,742	47,379,749
Revenue Deficiency	110,384,392	1,797,622	63,671,111	22,781,602
% COS Recovered	**34.8%**	**63.2%**	**47.0%**	**51.9%**

From COSS:				
BASE REVENUES FROM RATES	58,452,741	3,069,538	56,959,275	24,494,557
PRO FORMA TO BASE REVENUES FROM RATES	(456,828)	(54,668)	(1,257,217)	(494,918)
Credit for Adjustor Transfers				
DSMAC Transfer	605,657	28,629	523,755	242,769
EIS Transfer	161,153	7,667	140,842	65,040
LFCR	1,561,802	98,476	1,077,443	713,556
TEAM	(1,352,368)	(57,474)	(893,467)	(422,857)
Revenues	58,972,157	3,092,168	56,550,631	24,598,147

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Costs
Delivered Load (Bottom-Up)

Allocator	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Production Demand				
Back-up Costs				
4-CP (MW) Self-Supply	113.2	2.5	71.6	28.2
Capacity Value	40%	40%	40%	40%
Back-up Power Requirements (MW)	67.9	1.5	43.0	16.9
Cost per kW per month	10.34	10.34	10.34	10.34
COS	**8,427,507**	**186,175**	**5,337,007**	**2,097,568**
Reserves				
4-CP (MW) Self-Supply	113.2	2.5	71.6	28.2
Capacity Value	40%	40%	40%	40%
Firm portion of self-supply	45.3	1.0	28.6	11.3
Reserve margin	15%	15%	15%	15%
Required Reserves (MW)	6.8	0.2	4.3	1.7
Cost per kW per month	10.34	10.34	10.34	10.34
COS	**843,992**	**24,823**	**533,701**	**210,998**
Other Generator Services				
Solar Self-Supply MWh	401,245	10,130	224,200	97,315
Net metered MWh	474,571	9,071	-	-
Total applcable MWh	875,816	19,201	224,200	97,315
Cost per kWh	0.003	0.003	0.003	0.003
COS	**2,627,448**	**57,603**	**672,600**	**291,945**
Transmission				
Total 4CP allocator (MW)	7,299			
Trans Revenue Req - total retail	271,980,895			
line losses	9.21%			
4-CP (MW) - delivered load	262.2	7.6	99.6	42.4
at generator	286.3	7.6	99.6	42.4
transmission allocation %	3.92%	0.10%	1.36%	0.58%
transmission allocation $	10,669,471	283,179	3,711,142	1,579,843
	4,466,227	205,001	3,753,894	1,757,909
	6,203,245	**78,178**	**(42,753)**	**(178,066)**
Back-up Costs				
4-CP (MW) Self-Supply	113.2	2.5	71.6	28.2
Capacity Value	40%	40%	40%	40%
Back-up Power Requirements (MW)	67.9	1.5	43.0	16.9
Cost per kW per month	1.90	1.90	1.90	1.90
COS	**1,548,621**	**34,211**	**980,718**	**385,445**
Distribution Substation				
Self-Supply Back-up				
Summer NCP (MW) Self-Supply	44.8	1.1	24.5	9.2
Capacity Value	40%	40%	40%	40%
Back-up Grid Requirements (MW)	26.9	0.7	14.7	5.5
Cost per kW per month	0.92	0.92	0.92	0.92
COS	**295,850**	**7,699**	**161,673**	**60,490**

ARIZONA PUBLIC SERVICE COMPANY
Calculation of Solar Costs
Delivered Load (Bottom-Up)

Allocator	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Distribution Primary				
Self-Supply Back-up				
Summer NCP (MW) Self-Supply	44.8	1.1	24.5	9.2
Capacity Value	40%	40%	40%	40%
Back-up Grid Requirements (MW)	26.9	0.7	14.7	5.5
Cost per kW per month	3.60	3.60	3.60	3.60
COS	**1,161,715**	**30,231**	**634,841**	**237,525**
Distribution Secondary (Demand Classified)				
Site Load (Ind Max)				
Ind Max (MW) Self-Supply	71.2	1.5	44.5	16.4
Cost per kW per month	2.50	2.50	2.50	2.50
COS	**2,133,772**	**44,953**	**1,333,608**	**491,487**
Exports				
Export Grid Costs				
Annual Export MWh	474,571	9,071	366,080	134,303
Primary Grid cost per kWh	0.0259	0.0259	0.0259	0.0259
COS	**12,293,316**	**234,976**	**9,482,958**	**3,478,993**
Value of Exports	Site COSS			
Annual Export MWh	474,571	9,071	366,080	134,303
Value per kWh	(0.038321)	(0.038321)	(0.038321)	(0.038321)
Value	**(18,186,035)**	**(347,610)**	**(14,028,552)**	**(5,146,625)**
Cost of RCP Purchases				
RCP Purchases (MWh)	-	-	366,080	134,303
Average RCP rate per kWh	-	-	0.1186	0.1176
Value	**-**	**-**	**43,420,498**	**15,789,804**
Cost of EPR-6 Purchases				
EPR-6 Purchases (MWh)	79,293	1,615	-	-
Average rate per kWh	0.02895	0.02895	-	-
Value	**2,295,524**	**46,762**	**-**	**-**
Cost of Net Metering Exports	already reflected in the reduced revenue for the class			
Net Cost of Exports	**(3,597,195)**	**(65,872)**	**38,874,904**	**14,122,172**

Adjustments: revenue requirements additional to those reflected in the Delivered Load COS

Allocator	Legacy Solar (Energy)	Legacy Solar (Demand)	R-Solar (TOU)	R-Solar (Demand)
Production Demand	11,898,947	268,601	6,543,308	2,600,511
Transmission	7,751,866	112,389	937,965	207,379
Distribution Substation	295,850	7,699	161,673	60,490
Distribution Primary	1,161,715	30,231	634,841	237,525
Distribution Secondary (Demand Classified)	2,133,772	44,953	1,333,608	491,487
Net Cost of Exports	(3,597,195)	(65,872)	38,874,904	14,122,172
Total	**19,644,955**	**398,001**	**48,486,299**	**17,719,564**

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	$ 6,315,975	48.07%	3.85%	1.85%
2.	Preferred Stock	-	0.00%	0.00%	0.00%
3.	Common Equity	6,822,261	51.93%	10.25%	5.32%
4.	Short-Term Debt	-	0.00%	0.00%	0.00%
5.	Total	$ 13,138,236	100.00%		7.17%

	Capital Structure with 1.0% FV Increment	Amount	%	Cost Rate	Weighted Avg
6.	Long-Term Debt	$ 5,054,982	30.48%	3.85%	1.17%
7.	Preferred Stock	-	0.00%	0.00%	0.00%
8.	Common Equity	5,460,895	32.93%	10.25%	3.38%
9.	Short-Term Debt	-	0.00%	0.00%	0.00%
10.	FVRB Increment	6,068,577	36.59%	1.00%	0.37%
11.	Total	$ 16,584,454	100.00%		4.92%

	Fair Value Increment Calculation	Fair Value	Original Cost
12.	Rate Base	$ 16,584,454	$ 10,515,877
13.	Rate of Return	4.92%	7.17%
14.	Required Operating Income	$ 815,955	$ 753,988
15.	Adjusted Operating Income	237,851	$ 237,851
16.	Adjusted Operating Income Deficiency (line 14 - line 15)	$ 578,104	$ 516,137
17.	Revenue Conversion Factor	1.3359	1.3359
18.	Increase in Base Revenue Requirements (line 16 * line 17)	$ 772,272	$ 689,492
19.	Fair Value Increment	$ 82,780	
	RCND Rate Base	$ 22,653,031	