REBUTTAL TESTIMONY OF LELAND R. SNOOK

On Behalf of Arizona Public Service Company

Docket No. E-01345A-19-0236

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REBUTTAL TESTIMONY OF LELAND R. SNOOK
ON BEHALF OF ARIZONA PUBLIC SERVICE COMPANY
(Docket No. E-01345A-19-0236)

I. INTRODUCTION

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

A. My name is Leland R. Snook. I am the Director of Rates and Rate Strategy for Arizona Public Service Company (APS or Company). I have management responsibility for all aspects relating to rate strategy and specific rates and prices. My business address is 400 North 5th Street, Phoenix, Arizona 85004.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS MATTER?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I sponsor the jurisdictional allocation of various updates to the Company's Standard Filing Requirements (SFR), an update to the Fair Value Rate Base (FVRB), Fair Value Increment (FVI), and Fair Value Rate of Return (FVROR). I also address Staff and intervenor criticisms for several recommended adjustments to APS's requested revenue requirement, APS's AG-X/AG-Y proposal, APS's Cost of Service Study (COSS), and APS's general service and school rates recommendations. I also sponsor a new adjustment mechanism called the Advanced Energy Mechanism (AEM).

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. I rebut a number of Staff and intervenor unreasonable adjustments to the revenue requirement and summarize the overall financial impact of changes APS has incorporated into its rebuttal revenue requirement. I explain why parties' AG-X/AG-Y proposals are largely unworkable because they would shift cost to other customers. I address parties' proposed modifications to APS's COSS and explain why APS's present allocation methods are sound and appropriate. I sponsor the term sheet for APS's proposed AEM, which will be critical to support the ambitious goal of providing 100% clean energy by 2050, with interim targets. Lastly, I explain why the general service rate design recommendations by the Solar Energy Industries Association (SEIA) and Arizona School Boards Association (ASBA)/Arizona Association of School Business Officials (AASBO) are flawed and should not be adopted by the Arizona Corporation Commission (ACC or Commission). While I may not address every detail related to intervenors' recommendations, it should not be interpreted that I agree with each position unless specifically stated within my testimony.

III. STANDARD FILING REQUIREMENTS

Q. ARE YOU SPONSORING ANY UPDATES TO SFR SCHEDULES?

A. Yes. I am sponsoring an update to SFR A-1, B-1, B-2, C-1 and C-2, specifically related to the Commission jurisdictional allocation.

Q. PLEASE DESCRIBE THE UPDATES TO THESE SFRS.

A. APS has made several changes to its original filing. Some surfaced through the discovery process in this case, and others were anticipated changes previously described in the Company's Direct Testimony, such as the update to post-Test Year plant (PTYP) to reflect actual plant balances through June 2020. In addition, APS is incorporating some recommendations from Staff and intervenors. These rate-base and income-statement adjustments result in changes to APS's FVRB and the FVI to rate base. In addition, as discussed by APS witnesses Barbara Lockwood and Ann Bulkley, APS has revised its requested return on equity (ROE) and the return on the FVI. The net effect of all these changes reduces the Company's requested revenue requirement by approximately $15 million.

Q. WHAT IS APS'S POSITION ON STAFF WITNESS RALPH SMITH'S ADJUSTMENT TO INCLUDE BAD DEBT IN THE CALCULATION OF THE REVENUE CONVERSION FACTOR [ATTACHMENT RCS-2, A-1]?

A. The Company accepts this adjustment. APS updated the calculation utilizing an uncollectible revenue factor of 0.41% and has provided the new information in Rebuttal SFR Schedule C-3, which is sponsored by APS witness Elizabeth Blankenship. The revised revenue conversion factor is 1.3346, which is in agreement with the revenue conversion factor reflected in Staff witness Ralph Smith's attachment RCS-2, A-1.

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

Q. DID APS UPDATE ITS FVRB AND RATE OF RETURN FOR THE ADJUSTED TEST YEAR?

A. Yes. APS has increased its FVRB by $4.941 million. Thus, the Company's FVRB in APS's Rebuttal Testimony is now $12,315,204. The net result of all Rebuttal Testimony rate base changes, plus a downward adjustment to both the requested ROE and the FVI rate of return, produce a revised fair value rate of return of 5.51%.

Q. WHY WAS THIS UPDATE APPROPRIATE?

A. With an update for the PTYP and a number of corrections to the Company's Application, both the Original Cost Rate Base (OCRB) and Reconstructed Cost New Less Depreciation (RCND) rate based have changed. Also, APS reduced its requested ROE and FVI rate of return.

Q. DID APS USE THE SAME METHODOLOGY TO COMPUTE FVRB AND THE FVI AS IN THE APPLICATION?

A. Yes. I have revised the inputs but have used the same method of computation. Please see Attachment LRS-01RB and revised SFR Schedule A-1, line 9.

V. <u>PRO FORMA ADJUSTMENTS</u>

Q. ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION (AECC) WITNESS KEVIN HIGGINS ADVOCATES THE USE OF AVERAGE RATE BASE VERSUS YEAR-END VALUES FOR POST-TEST YEAR PLANT (PTYP) ADJUSTMENTS TO THE TEST-YEAR. DO YOU AGREE?

A. No. PTYP rate base and related adjustments, such as rolling forward accumulated depreciation for existing plant to the same PTYP end of period are known and measurable changes to the Test Year and should reflect year-end values of PTYP period, not average values. If there are prudent known and measurable changes to rate base in the Test Year, they should be 100% recoverable. AECC witness Higgins does not appear to contest the prudency of the expense, and therefore, his attempts to allow less than full recovery should be rejected.

Q. IS AECC'S POSITION TO ADJUST THE CUSTOMER AND SALES ANNUALIZATION PRO FROMA TO REFLECT CUSTOMER GROWTH POST-TEST YEAR APPROPRIATE?

A. No. APS included 12 months of PTYP in its application in this proceeding, but APS excluded any plant related to customer growth. Pursuant to the Settlement in the Company's last rate case, APS was given the choice of including PTYP related to growth and making an adjustment similar to what AECC is proposing or excluding growth-related plant and not imputing customer growth. AECC's imputation of post-Test Year customer and sales growth into the test period results in a double counting for the effects related to growth.

Q. AECC ALSO PROPOSES A DEBT RETURN ON APS'S REMAINING BOOK VALUE FOR NAVAJO GENERATING STATION (NGS). DO YOU AGREE WITH THIS ADJUSTMENT?

A. No. NGS served APS's customers for over 40 years, and the remaining book value of the asset is merely the final cost of a long-asset life. While depreciation rates and salvage costs are in theory supposed to result in a value close to zero at the end of plant life, in the instance where it does not, a regulatory asset or liability is created. This is not a reflection on whether the capital cost over the life of the facility was prudently incurred, it is just a mismatch in the timing. The regulatory asset for the remaining book value for NGS reflects prudently-incurred cost over the long life of the asset and therefore should receive normal regulatory asset treatment at the weighted average cost of capital (WACC) established in this proceeding. In this case, APS is still proposing recovery of the remaining book value over the original NGS life of 2026, which prevents potential rate pressure from trying to accelerate recovery to more closely match the closure date in 2019. A debt-only return is essentially a partial disallowance of prudently-incurred costs as the Company funded the related assets with a mix of debt and equity. Such a disallowance effectively punishes APS for closing or terminating its interest in the generating asset.

Q. DO YOU AGREE WITH THE FEDERAL EXECUTIVE AGENCIES' (FEA) PROPOSAL TO DISALLOW THE OCOTILLO MODERNIZATION PROJECT (OMP) DEFERRED COST?

A. No, I do not. FEA witness Michael Gorman alleges that APS has not justified including the OMP deferral in rates. The OMP accounting mechanism was set up in a Commission order supported by FEA to defer the costs of owning and operating the plant, until a determination of prudence could be made. FEA correctly concludes the OMP asset is prudent, but I disagree with his proposal to disallow the deferral.

Q. FEA ARGUES THAT APS'S REVENUES DURING THE COST DEFERRAL PERIOD WERE SUFFICIENT FOR APS TO EARN A FAIR RETURN WITHOUT THE NEED FOR SUCH A DEFERRAL. IS HE CORRECT?

A. No. Counter to FEA's claim, APS has demonstrated that its current rates were insufficient to earn its authorized ROE even with the ability to defer costs related to OMP. APS's unadjusted jurisdictional ROE in the Test Year was 9.7%, as compared to the currently authorized ROE of 10.0%. It is important to note that this actual return in the Test Year included a deferral of the OMP costs. However, had these costs been expensed, as would have been the case absent an accounting deferral order, the actual return would have been even lower. FEA's testimony ignores the fact that APS's current authorized ROE is 10.0%, and without the ability to defer OMP costs, the actual ACC jurisdictional return would have been well below the authorized return. On this point, FEA erroneously relies on FEA witness Christopher Walters' derivation of an ROE of 9.3% that is below the test year actual return of 9.7%. However, as I mentioned previously, APS's authorized ROE during the test year was 10.0%.

Q. DID THE OVERLAND REPORT OR THE DRAFT OVERLAND REPORT COME TO A SIMILAR CONCLUSION?

A. No. The final report from Overland Consulting (Overland) that was docketed in the APS Rate Review matter (Docket No. E-01345A-19-0003) concluded that a number of factors had changed since APS's 2015 Test Year rate case, and APS should file a new rate case to determine if its rates were just and reasonable. The Overland report did not conclude that APS was over-earning. Four months later, in the same docket, earlier drafts of the Overland report were docketed. These drafts discussed a hypothetical scenario that did not reflect actual circumstances.

Q. PLEASE ELABORATE. WHY DO YOU DESCRIBE THE DRAFT REPORT'S ANALYSIS AS A HYPOTHETICAL SCENARIO?

A. In one of its drafts, Overland disregarded the 10% authorized ROE set by the Commission in Decision No. 76295 and substituted a new authorized equity return of 9.0%, which was not approved by the Commission or consistent with its prior decision. Overland merely concluded that if APS's authorized return were only 9.0%, then APS's actual return might have exceeded that number. Of course, the cost of equity found by the Commission was 10.0%, not 9.0%. In discovery for the

APS Rate Review matter, APS provided Overland with actual jurisdictional results, which demonstrated APS earned less than its then-authorized cost of equity, 10.0%. The Overland draft report also used lower debt costs than those found by the ACC. Overland added to its analysis several potential pro forma adjustments to the 2018 calendar year results, but it was not a comprehensive list of proforma adjustments that would be included in an actual rate case filing. Most notably, there was no adjustment for PTYP and no fair value adjustment. In summary, Overland's draft report came to the unremarkable conclusion that if APS had spent less in the 2018 calendar year, APS would have had more net income and a higher return on equity – not that the Company was actually over-earning.

Q. DO YOU BELIEVE THAT FEA WITNESS MICHAEL GORMAN'S DEFERRAL PROPOSAL IS INAPPROPRIATE REGARDLESS OF APS'S LEVEL OF HISTORIC EARNINGS?

A. Yes. The allowed recovery of a deferral, or of any asset for that matter, should not be contingent on prior year earnings, as claimed by FEA witness Gorman. By that same reasoning, APS would be able to increase the requested recovery of a deferral in a rate case if it earned less than the currently-allowed rate of return in the years since the last rate case.

Q. DOES FEA WITNESS GORMAN HAVE AN ALTERNATIVE PROPOSAL IF THE ACC ALLOWS RECOVERY OF THE DEFERRED COSTS?

A. Yes, and it should also be rejected. FEA witness Gorman proposes to use a debt return on the amortization of the deferred costs and a levelized cost recovery over the amortization period. The use of a debt return only on the regulatory asset created by the deferred costs is contrary to normal regulatory asset treatment. APS was authorized a debt return as the carrying cost during the deferral period, but the regulatory asset should receive the same treatment as any other asset in APS's rate base.

Q. THE RESIDENTIAL UTILITY CONSUMER'S OFFICE (RUCO) PROPOSES TO ACCELERATE THE AMORTIZATION OF PRODUCTION PLANT GENERATION-RELATED ASSETS. PLEASE RESPOND.

A. RUCO witness Frank Radigan does not provide any logical support for this proposal. Essentially, such a rapid amortization would have an adverse impact on customer rates. As I indicated previously, these regulatory assets are the final settling costs for assets that reliably served APS customers for over 40 years. I disagree with the characterization of these asset costs as stranded costs – it is merely a reflection of a mismatch in the cost recovery of the asset over a long period of time. While one would ideally target the book value of a generation asset to be zero, often there is a positive or negative plant balance. This regulatory asset or liability, as the case may be, should be treated consistently. For this category of regulatory assets, APS has proposed to continue to amortize the remaining book value consistent with the asset's depreciation schedule prior to retirement. This approach does not increase or decrease the recovery of the remaining capital cost and is a balanced approach to help keep customer rates affordable.

Q. RUCO ALSO PROPOSES TO LIMIT COST RECOVERY OF APS'S EDISON ELECTRIC INSTITUTE (EEI) AND ELECTRIC POWER RESEARCH INSTITUTE (EPRI) DUES. IS THIS APPROPRIATE?

A. No, it is not. For APS's EEI dues, APS already excludes the portion of EEI dues related to legislative or regulatory advocacy. These same dues are RUCO witness Radigan's justification for reducing non-advocacy EEI dues by 50%. However, APS already removed the advocacy-related dues in its application. The remaining dues should be fully recoverable as a prudent expense to be a member of this valuable electric industry trade organization. Further, EPRI is an industry research organization that is important for APS to participate in to stay abreast of the evolving electric utility industry. These necessary expenses should be fully recoverable as prudently-incurred costs. Particularly in today's rapidly-changing electric industry, it is not a viable option for APS to drop its membership in EPRI.

Q. ARE YOU SPONSORING ANY NEW OR UPDATED PRO FORMAS IN REBUTTAL?

A. Yes. Through the discovery process, the Company realized it had inadvertently omitted a revenue pro forma to account for the AG-X program mitigation that occurs through the Power Supply Adjustor (PSA) mechanism, which amounts to $15 million in revenue annually, that should have been a reduction in the revenue deficiency APS is requesting in this rate case. Thus, the revised Standard Filing Requirement (SFR) C-2, attached to APS witness Elizabeth Blankenship's Rebuttal Testimony, incorporates this new pro forma. This pro forma can be seen on SFR C-2, page 18, column 52.

Q. WHAT IS THIS PRO FORMA, AND WHY IS IT NECESSARY?

A. As part of the AG-X program, APS retains $1.25 million in margins from wholesale sales per month from the margins that credit the overall APS fuel costs in the PSA. This pro forma corrects APS's original application filing to reflect that these revenues are retained through the PSA mechanism, and the $15 million annual amount should not be reflected in the revenue deficiency. Therefore, the $15 million is now correctly reflected in both the ongoing PSA Plan of Administration and in the retail jurisdictional revenue requirement.

Q. ARE THERE ANY OTHER NEW/UPDATED PRO FORMAS?

A. Yes. APS adopts Staff's recommendation to increase the base fuel rate from $3.0167 to $3.1451. This recommendation was based on an updated fuel forecast provided by APS in discovery. APS believes its original estimate of base fuel costs was reasonable but will not contest Staff's position. This pro forma can be seen on SFR C-2, page 2, column 6.

Q. WOULD YOU PLEASE SUMMARIZE THESE PROPOSED CHANGES TO ADJUSTED TEST YEAR OPERATING INCOME, RATE BASE AND RATE OF RETURN?

A. Please see Table 1 below for major components of the changes (numbers have been rounded for ease of presentation). The income statement and rate base pro formas are discussed by either APS witness Blankenship or myself. The changes to requested ROE and return on FVI are discussed by APS witness Barbara Lockwood. The annual revenue requested in rebuttal is $169 million, which equates to a 5.14% average bill impact.

Table 1. APS Revised Revenue Requirement

APS Revised Revenue Requirement	Dollars ($MM)	Bill Impact
Total Revenue Deficiency in APS's Application	184	5.60%
Rebuttal Base Rate Impact		
Income Statement and Rate Base Pro Forma Changes		
New base fuel rate	25	0.77%
Depreciation Update	(20)	-0.61%
Normalize Employee Benefits Update	(10)	-0.29%
AG-X Revenue Provision in PSA Update	(11)	-0.34%
Other C-2 Pro Forma Updates	(10)	-0.31%
Misc. Adjustments	(3)	-0.09%
B-2 Pro Forma Updates	2	0.07%
Changes to Requested Returns		
Decrease in ROE	(9)	-0.29%
Decrease in Return on FVI & RCND Update	(10)	-0.29%
Other		
Transmission Expense Correction	18	0.53%
Adjustor Impact		
TEAM Adjustor	(119)	-3.62%
Other Adjustor Mechanisms	4	0.12%
Revised Net Base Rate Increase	**41**	**1.23%**
Rebuttal Adjustor Impact		
Removal of TEAM credit	119	3.62%
Advanced Energy Mechanism (AEM)	13	0.41%
Other Adjustor Mechanisms	(4)	-0.12%
Net Adjustor Changes	**128**	**3.91%**
Total Rebuttal Customer Bill Impact	**169**	**5.14%**

To accurately reflect the bill impact of the Company's revised rate request, which is an average of 5.14% for all customers and 4.99% for residential customers, I have included the impact of adjustor changes such as the proposed recovery of the Coal Community Transition (CCT) commitment described by APS witnesses Jeff Guldner and Barbara Lockwood. This is a total of $13 million recovered through the AEM. I discuss the details of this mechanism elsewhere in my Rebuttal Testimony.

Q. ARE THERE ANY ITEMS IN THE TABLE THAT HAVE NOT BEEN DISCUSSED IN APS REBUTTAL TESTIMONY?

A. Yes. I have included a line item under "Other Impacts" that were identified in the discovery process. Transmission expense for March 2019 was inadvertently omitted from the model, resulting in an understatement of revenue requirement by $18 million.

VI. <u>FORMULA RATE, THE AEM MECHANISM AND OTHER ADJUSTOR MECHANISMS</u>

A. *Existing Adjustors*

Q. DID INTERVENORS WEIGH IN ON APS'S CURRENT ADJUSTOR MECHANISMS OR APS'S FORMULA RATE PROPOSAL?

A. Yes. I note that Staff witness Ralph Smith agrees with APS's proposal to not transfer the balance in the Lost Fixed Cost Recovery (LFCR) adjustor into base rates. Additionally, several parties provided commentary on APS's alternative formula rate proposal.

Q. SOUTHWEST ENERGY EFFICIENCY PROJECT (SWEEP)/WESTERN RESOURCE ADVOCATES (WRA) SUGGESTS THAT APS'S LFCR MECHANISM SHOULD BOTH BE ZEROED OUT IN THIS CASE AND PROSPECTIVELY HAVE AN EARNINGS TEST. ARE EITHER OF THESE RECOMMENDATIONS APPROPRIATE?

A. No. APS has no theoretical objection to transferring all unrecovered fixed costs recoverable under the LFCR to base rates, essentially zeroing out the LFCR as of the rate effective date. However, the mechanics of this are complicated, and as the last case demonstrated, the bill impact is difficult to explain to customers. Thus, neither APS nor Staff recommend this course of action at this time.

As to the earnings test, LFCR is recovery of lost fixed costs irrespective of a utility's earnings. LFCR is based on actual observed reduced sales that result from Energy

Efficiency (EE) and Distributed Generation (DG) programs – not a hypothetical change in sales. The LFCR is intended to eliminate the disincentive of the utility to engage in EE and support DG programs. Putting an earnings test on the LFCR would undermine the intent of this mechanism.

Q. INTEVENOR RICHARD GAYER ALLEGES THE ADJUSTOR TRANSFER ACTUALLY NEVER OCCURRED IN APS'S PREVIOUS RATE CASE. PLEASE RESPOND.

A. Intervenor Gayer is mistaken, and his allegation was conclusively addressed in Docket No. E-01345A-18-0002. Decision No. 77292 in the aforementioned docket specifically found as a finding of fact and conclusion of law that the adjustor transfer occurred in accordance with the normal functioning of the various adjustor mechanisms.

Q. IS THE COMPANY PROPOSING ANY OTHER CHANGES TO ADJUSTOR MECHANISMS OTHER THAN WHAT WAS PROPOSED IN ITS DIRECT TESTIMONY?

A. Yes. APS now believes it is more appropriate to retain the current Tax Expense Adjustor Mechanism (TEAM) rather than eliminate it. APS proposes to set the adjustor value to zero but retain the mechanism in anticipation of future changes to federal or state income tax policy. Keeping this adjustor would allow APS to properly reflect changes in tax expense moving forward. Without it, depending on timing, the Company could be forced to file an immediate rate case to address tax changes in the future.

B. *Formula Rates and the AEM*

Q. DOES ANY PARTY SUPPORT APS'S FORMULA RATE PROPOSAL?

A. No. Parties oppose this concept at this time for a variety of reasons. Because this proposal was: 1) an alternative proposal for consideration; 2) parties did not propose to eliminate the current suite of adjustor mechanisms; and 3) the concept did not generate support, APS is no longer pursuing this proposal as part of its rebuttal case. As such, I will not respond in detail to parties who provided testimony opposing the formula rate proposal.

While parties did not support comprehensively moving to using a formula rate mechanism to more closely match revenue recovery with expenses, there exists an opportunity to continue to align interests from a number of parties, while providing timely cost recovery for APS in its efforts to support a clean energy future for Arizona. To that end, APS is proposing a new adjustor described in the rebuttal testimonies of APS witnesses Guldner and Lockwood – an adjustor the Company calls the AEM.

Q. DID APS ANNOUNCE A CLEAN ENERGY PLAN IN JANUARY OF 2020 AFTER THIS RATE CASE APPLCATION WAS FILED?

A. Yes. As discussed in more detail by APS witnesses Guldner and Lockwood, APS committed to be 100% clean (carbon free) by 2050, with interim targets as well. The Clean Energy Commitment is an ambitious undertaking, and to be successful, APS will need timely cost recovery of its investments to meet the commitment.

Q. HOW IS APS PROPSING IT RECOVER THESE COSTS?

A. APS is proposing to recover investments related to the Clean Energy Commitment through the AEM. In addition, because they all encourage a cleaner energy future, the AEM could be modified to include the existing Demand Side Management (DSM), renewable energy, and LFCR mechanisms after a period of time. In APS's proposal, the CCT funding discussed by APS witnesses Guldner and Lockwood would be recovered through this adjustor. APS witnesses Guldner and Lockwood also both discuss the importance of timely recovery in pursuing clean energy goals, and I have included an AEM term sheet as Attachment LRS-02RB.

Q. WHAT COSTS WOULD BE RECOVERABLE IN THIS PROPOSED AEM?

A. This mechanism would provide for timely cost recovery of the capital carrying cost and expense of APS's approved and prudent clean plan investment, including APS-owned, newly-constructed or acquired plants which are not already recovered in base rates or through another Commission-approved cost adjustment. For example, purchased power costs and third-party storage costs are already includable in the PSA mechanism, and a portion of renewable costs are recovered in base rates.

Q. HOW WOULD CLEAN ENERGY INVESTMENTS BE DETERMINED?

A. Clean energy investments would be authorized by the Integrated Resource Plan (IRP) Action Plan or Clean Energy Implementation Plan approval by the ACC and a subject to a robust request for proposal (RFP) process. Approved and prudent acquisitions that result from the IRP Action Plan or Clean Energy Implementation Plan and RFP process would be included in the AEM for cost recovery.

Q. IF THE COMMISSION DOES NOT APPROVE THIS ADVANCED ENERGY MECHANISM, ARE THERE OTHER ALTERNATIVES USING EXISTING MECHANISMS?

A. Yes, there is. APS could use the existing Renewable Energy Adjustment Charge (REAC), DSMAC, and LFCR for clean energy plan cost recovery. The REAC would recover the capital carrying cost of APS-owned resources, including storage-related facilities. In this scenario, the CCT funding could be added to base rates.

VII. <u>ENERGY EFFICIENCY PROPOSAL</u>

Q. VARIOUS INTERVENORS PROPOSE CHANGES TO THE AMOUNT OF DSM PROGRAM COSTS TO BE INCLUDED IN BASE RATES. DOES APS SUPPORT THESE PROPOSED CHANGES?

A. Not at this time. AECC proposes that no DSM program costs be recovered through base rates, and SWEEP/WRA witness Brendon Baatz proposes that the amount of DSM in base rates be increased from $20 million to $65 million. APS is open to increasing the amount of DSM program costs being recovered in base rates but proposes that any addition be revenue neutral, meaning the increased amount would not exceed the Test Year amount in the DSM adjustor.

Q. WHAT IS THE PROPOSAL OUTLINED BY SWEEP/WRA FOR CAPITALIZATION OF DSM COSTS?

A. SWEEP/WRA recommend that APS be allowed to earn a rate of return on EE investment. This would be effectuated by creating a regulatory asset for the annual expenditure and amortizing that over a 7-year period, with a return at the after-tax cost of capital on the unamortized balance of this asset.

Q. WHAT ARE SOME PROS AND CONS OF CAPITALIZING DSM EXPENSES?

A. By amortizing DSM costs over a period of time, capitalization better aligns the costs of the resource with the timing of benefits. It protects customers by ensuring DSM costs are appropriately apportioned across a period of time closer to the 10-year average measure life of the DSM portfolio, rather than asking current customers to fully fund all DSM costs upfront. It also helps put DSM investments on a more level playing field with other investments and can encourage investments in appropriate demand-side resources. Implementing capitalization at this time could be particularly valuable as a tool to help mitigate the economic impacts of COVID-19 by providing short-term rate relief, while still enabling robust investments in EE and other DSM resources.

On the other hand, the impacts on total costs must also be considered. Capitalizing costs will increase the total cost of demand-side resources and could potentially limit future program spending on new programs due to the carrying costs of amortized investments over time. This potential impact on costs must be further analyzed and addressed, as well as creating provisions for a transition period to define how amortized costs would be recovered if the Commission were to revert to an operating expense approach at some point in the future. Finally, any capitalization plan must address the unique risks associated with deferring DSM costs which would be considered as a regulatory asset with no value outside of the regulatory construct – requiring a clear framework to be established to provide reasonable assurance of future cost recovery.

Q. WHAT IS APS'S POSITION ON SWEEP/WRA'S PROPOSAL TO CAPITALIZE DSM EXPENSES?

A. APS is interested in the proposal. As the EE focus in Arizona has shifted to peak management, I believe that this type of proposal aligns with the general proposition that EE should be treated like supply-side resources.

Q. IS APS RECOMMENDING ADOPTION OF THE SWEEP/WRA PROPOSAL AT THIS TIME?

A. APS is interested in this proposal, but is still analyzing the impacts, as stated above. APS welcomes feedback from other parties on this topic.

VIII. COMMERCIAL BUY-THROUGH PROGRAMS (AG-X/AG-Y)

Q. SEVERAL INTERVENORS ASSERT THAT APS'S PROPOSED PROGRAM IS INCONSISTENT WITH THE ACC'S POLICY STATEMENT REGARDING AG-Y. DO YOU AGREE?

A. Not at all. The policy statement clearly states that the program shall not shift costs to non-participating customers.[1] This is a point conveniently left out by intervenors. In fact, while AECC erroneously claims that the PSA mitigation is no longer needed, without it there would be a revenue shortfall that would need to be made up through higher rates to other customers to offset the cost shift created by AG-X. AECC suggests a similar mitigation mechanism would be needed for their AG-Y proposal

[1] Decision No. 77043, AG-Y Policy Statement at 3.

that essentially mirrors AG-X. Importantly, Staff supports the program because it does not shift costs to other customers.

Q. IS THERE ANYTHING ELSE YOU WOULD LIKE TO POINT OUT ABOUT THE POLICY STATEMENT?

A. Yes, the policy statement cites that a benefit of this program should be that it "provides medium and large commercial customers increased flexibility to manage their energy costs while insulating other customers from cost shifting."[2] This is precisely what APS's proposal does.

Q. DID VARIOUS INTERVENORS MAKE SUGGESTIONS REGARDING THE AG-Y PROPOSAL?

A. Yes. AECC, Calpine Energy Solutions (Calpine), Walmart Inc., The Kroger Company, Staff and FEA all provide testimony regarding APS's proposed AG-Y program. Staff did not oppose the proposed program. Generally, the market brokers and large customer constituents proposed to expand the current AG-X program rather than offer a new AG-Y program. FEA alternatively proposes some modifications to the eligibility for APS's proposed AG-Y program if the AG-X program is not expanded.

Q. DOES THE COMPANY AGREE WITH THE RECOMMENDATIONS TO EXPAND AG-X?

A. No. The current AG-X program cannot be expanded, either by allowing for growth in the current program or by changing the proposed AG-Y program into an AG-X concept, without requiring additional mitigation through the PSA, increased AG-X/AG-Y charges, and removing the buy-through priority to deliver power at the Palo Verde market hub. Most importantly, resource adequacy deficiencies in the current program would have to be addressed. Despite the issues discussed below, APS has

[2] Decision No. 77043, AG-Y Policy Statement at 1.

not proposed changes to the AG-X program in this case. Therefore, APS continues to support its AG-Y proposal in this case because it provides customers with a market price for their energy, if the customer so desires, without creating the potential to shift costs to other customers as can occur in the current AG-X program.

Q. PLEASE DESCRIBE HOW THE CURRENT AG-X PROGRAM WORKS.

A. The current AG-X program allows customers to receive their power supply from a third-party generation service provider (GSP) rather than from APS. APS continues to provide transmission and distribution grid services according to the customer's retail rate schedule. The customer avoids the unbundled generation capacity and energy charges in the retail rate, including the PSA Adjustor charge, but pays a reserve capacity charge and an administrative fee. They also pay for the generation charges from the GSP.

Q. PLEASE ELABORATE ON THE COST DEFICIENCIES IN THE CURRENT AG-X PROGRAM.

A. The primary deficiency in the current AG-X program is that the GSPs do not provide all of the generation services needed to serve the customer – they do not act as an alternative to, or substitute for, APS. They do not serve the customer with power plants that can ramp up and down to match the customer's monthly, daily, or hourly loads and provide a firm resource to ensure a reliable power supply for the customer. Rather, they typically serve the customer through block energy purchases from wholesale brokers or suppliers like the California Independent System Operator (CAISO), which can be interrupted during critical load hours. They leave it to APS to provide the capacity resources and reserves needed to reliably serve the customer's load.

Q. CALPINE WITNESS GREG BASS CLAIMS THAT THEY ARE PROVIDING FIRM POWER. DO YOU AGREE?

A. No. And by firm power, I mean providing both energy and capacity to reliably serve a customer from a power supply that provides resource adequacy for the load being served. Calpine witness Bass generally confuses capacity and energy in making his firm-power claim. The AG-X program requires that GSPs deliver power in a particular standard energy contract form called WSPP Schedule C, which is a firm energy contract. Calpine claims that this type of contract provides firm capacity, as well as energy. However, this is incorrect. The WSPP Schedule C is essentially an energy contract, which can be cut during critical hours and does not provide any of the power plant capacity attributes or resource adequacy requirements for ensuring a reliable supply of power to the customer.

Q. WERE THESE DEFICIENCIES HIGHLIGHTED IN THE RECENT POWER SHORTAGES IN THE SOUTHWEST?

A. Very much so. APS witness Brad Albert will elaborate on the Summer 2020 wholesale power market and events that occurred in the western states during a regional heat storm, but essentially AG-X participants had their schedules cut during peak hours, causing APS to use its own resources to serve AG-X customers' load.

Q. BUT CAN'T APS SIMPLY CURTAIL THE AG-X CUSTOMERS' LOAD IF THEIR POWER SUPPLY IS CUT DURING CRITICAL HOURS?

A. No, not under the current program. Furthermore, as the balancing authority, APS has an obligation to serve each of the customer loads in its area, even the AG-X loads that should be served by the GSPs. AG-X customers include hospitals, universities, grocery stores and retail stores, which expect to have reliable power, even if they participate in the AG-X program.

Q. CALPINE ALSO CLAIMS THE ONE-YEAR RETURN WARNING ALLEVIATES THE CAPACITY ISSUE. IS THIS CORRECT?

A. No. AG-X customers must provide a one-year warning before they can return to APS's generation service, under the retail rate schedule. Or, if the GSP defaults, they could be served at market index rates for up to one year. Calpine contends that this means that APS does not have to plan for any future power plant capacity for the AG-X customers. However, because the customer cannot be curtailed if the GSP fails to provide generation during critical times, this requirement does little to nothing to alleviate the need for APS to back up the GSP's supply.

Q. DO THE GSPS PAY FOR THE DEFICIENT CAPACITY THAT IS MADE UP BY APS DURING CRITICAL HOURS?

A. Only partially. The GSPs pay liquidated damages when their power supply is cut, which is based on the cost of replacement energy for the deficient hours. However, this replacement energy, which can be relatively high during critical hours, is only applied to the actual hours of deficiency and, therefore, is far less than the cost of an actual power plant or a capacity contract necessary for providing resource adequacy to customers.

Q. DO THE GSPS PAY FOR THE TYPE OF GENERATION NEEDED TO FOLLOW THEIR LOAD EACH SECOND?

A. Again, only partially. AG-X customers, like all retail customers, pay for a "regulation and frequency response" service in their retail transmission charge. This service recovers the cost of a very small amount of generation that can instantaneously ramp up and down, under automatic controls, to match supply with load at every instant. It covers small deviations in load each second that were not perfectly anticipated nor provided for with the scheduled power supply. However, if APS and other load-serving entities only provided blocks of power to serve their customers, similar to the GSP supply in the AG-X program, the cost for this service would undoubtedly be significantly higher. In fact, under this scenario, there could very likely not be enough resources to provide this service.

Q. DO THE AG-X CUSTOMERS PAY FOR THE OTHER CAPACITY SERVICES DISCUSSED?

A. Only partially. The AG-X customers pay a reserve capacity charge and transmission ancillary charges, but these charges only partially address the costs for these unprovided generation services. The remaining costs are mitigated through the retained PSA margins or are shifted to other customers.

Q. AECC CLAIMS THAT THE RESERVE CAPACITY CHARGE SHOULD BE SIGNIFICANTLY REDUCED. DO YOU AGREE?

A. No. AECC witness Kevin Higgins' proposal is based on an incorrect conception of the purpose for this charge. AECC mistakenly believes that the capacity reserve charge is some sort of payment for APS legacy power plants that are no longer needed to serve the AG-X customers. Therefore, AECC argues that the charge should be reduced because AG-X customers have been paying off these legacy power plant costs for some seven years.

This line of reasoning is simply incorrect. The reserve capacity charge partially recovers the costs of APS power plants that are still needed to serve the AG-X customers because of the deficiencies of the GSP power supply under the program discussed above. This is an ongoing annual cost that is not "paid down" in any manner. Therefore, the reserve capacity charge should not be reduced. As a matter of fact, the charge only partially recovers the costs of APS power plant capacity provided under the program.

Q. WHAT CHARGES SHOULD THE AG-X CUSTOMERS PAY?

A. Because APS continues to provide the generation capacity services for the AG-X customers, ideally, they should continue to pay the full unbundled generation capacity charge in their retail rate. They should continue to avoid paying the generation energy charge and the PSA Adjustor charge. However, in its current form, APS is not proposing these changes.

Q. ISN'T THAT PRECISELY THE CONCEPT OF THE PROPOSED AG-Y PROGRAM?

A. Yes, it is. Under the proposed AG-Y program, the customer would continue to pay the unbundled generation capacity charge in their retail rate – to pay for the capacity services provided by APS – and substitute the unbundled generation energy charges and PSA charges for a market rate. It would operate like a market generation rate should – providing bill savings consistent with the generation costs savings incurred under the program.

Q. THEN WHY DO CERTAIN GSPS AND CUSTOMER GROUPS OPPOSE THE AG-Y PROGRAM?

A. Under the AG-X program, the potential for customers to save money or GSPs to make money are greater. The generation capacity services that APS continues to provide under the AG-X program are effectively paid for by PSA mitigation or other customers, not the participants. This results in significantly higher benefits for the AG-X participants and GSPs, compared to the proposed AG-Y program, where the customer benefits are more consistent with the actual generation cost savings.

Q. WHAT DOES APS PROPOSE ON THIS ISSUE?

A. Consistent with the filed case, APS proposes to allow the current AG-X program to continue without revision and to provide the AG-Y program for additional customers that want to access market generation prices. If the Commission were to expand the AG-X program as suggested by GSPs and large-customer intervenors, it could not be done under the current construct without shifting costs significantly to non-participants.

Q. DID PARTIES PROPOSE OTHER CHANGES TO THE CURRENT AG-X PROGRAM THAT APS OPPOSES?

A. Yes. AECC witness Higgins proposes that the AG-X program allow for load growth. While APS supports accommodating reasonable load growth, this should not become a mechanism to dramatically increase the overall size of the program. One example would be if an extra-large customer in the program desired to double their existing load through an expansion. This would violate the intent of the overall program size limitation, which is important. Some reasonable amount of growth can be accommodated but should be limited. A 10 MW customer should not be able to add 10 MW, and an 80 MW customer should not be able to add 80 MW. A reasonable accommodation would be to limit growth to 10% of the original program allotment.

Q. DID PARTIES PROPOSE ANY CHANGES TO THE AG-X PROGRAM THAT THE COMPANY SUPPORTS?

A. Yes. There are two minor modifications that APS supports. First, Kroger witness Stephen Baron proposes the AG-X program allow for customers that aggregate accounts to be able to add accounts if the aggregate load falls below the 10 MW threshold due their participation in EE programs. APS agrees this would be a reasonable accommodation within the AG-X program, to allow locations to be added to get back to the original allocated program amount. Second, AECC suggests that APS change the scheduling procedure to allow for intra-day scheduling changes by the GSP. APS agrees this is a reasonable change to the current scheduling protocols. Such intra-day trading capabilities would have to be developed and integrated into APS's current scheduling platform and protocols. However, APS is committed to working with GSPs and customers to develop additional scheduling capabilities for the AG-X program.

Q. DO ANY OTHER PARTIES PRESENT TESTIMONY ON THE AG-Y PROPOSAL?

A. Yes, ASBA/AASBO discuss the program as well.

Q. DOES APS SUPPORT ASBA/AASBO'S RECOMMENDATION?

A. Schools are already eligible under APS's proposed AG-Y program, and there is no aggregation requirement. Therefore, (as discussed later in my testimony) APS does not support the aggregation recommendation.

While APS does not support a carve-out specifically for schools at this time, the AG-Y program is specifically designed for smaller customers, such as schools. APS agrees that the load characteristics of schools could be an ideal fit to maximize the benefit of the day-ahead pricing structure. I note that, once the proposed program has time to function, APS may lift the cap of 200 MW which would allow additional opportunities for participation.

Q. SOME PARTIES ADDRESS THE QUESTION OF RETAIL COMPETITION IN THIS DOCKET. PLEASE COMMENT.

A. APS agrees with Staff witness Phillip Metzger on this issue. Retail competition is a broader policy issue that can only be addressed in a retail competition docket. The Commission has a retail competition docket open for that discussion and potential rulemaking.[3] The issue is not appropriate to address in a utility-specific rate case.

IX. COST OF SERVICE STUDY (COSS)

A. *General Background*

Q. WHAT IS A COST OF SERVICE STUDY?

A. A cost of service study allocates the Test Year rate base and revenue requirements across various customer and rate classes based on a reasonable estimate of the cost responsibility for each class. The study compares the adjusted Test Year revenue

[3] Docket No. RE-00000A-18-0405.

with the allocated revenue requirement to determine a revenue deficiency for each class.

Q. HOW DOES APS CONDUCT THE COSS?

A. Costs are first separated into functional categories, such as production (generation), transmission and distribution. Within each of these functional categories, the costs are further classified into (sorted by) general cost drivers such as demand, energy and customer-related costs. Notably, customer-related costs are not driven by the amount of demand or energy used by the customer. After the cost components are sorted into a more manageable and logical form, specific cost allocators are developed within these broad categories. These allocators are then applied to the cost-driver information and rate class for each customer to determine cost responsibility for each class.

B. *Criticisms of the Company's COSS Other Than by Solar Advocates*

Q. DID YOU REVIEW THE TESTIMONY OF OTHER PARTIES CONCERNING THE COSS?

A. Yes, I did.

Q. WHAT IS YOUR GENERAL RESPONSE TO THESE CRITICISMS FROM THESE PARTIES?

A. First, cost-allocation methods are not black and white. Often, there is more than one valid way to allocate certain costs, and there are varying conceptual ideas on cost-of-service methods. However, APS uses cost-allocation methods that are conceptually valid, widely adopted by the industry, and accepted historically by the Commission. It is also important to be consistent in the allocation methods used in a COSS over time because it supports consistency in rate design and customer impacts. Therefore, from my perspective, there must be a compelling reason for changing the current COSS methods APS used in this and prior rate cases.

Q. WHAT CRITIQUES TO THE COSS DID STAFF PROVIDE?

A. Staff witness David Dismukes makes several recommendations to cost-allocation methods within the COSS. Most notably, he proposes APS use an Average and Peak, and four coincident peak months (June through September), designated as (A&P–4CP) rather than Average and Excess (A&E), for allocating capacity-related production costs. Additionally, he takes issue with APS's allocation of secondary distribution costs, which uses a Sum of Individual Max (SIM) allocator, and instead proposes APS use a 100% class non-coincident peak (NCP) allocator.

APS disagrees with Staff witness Dismukes' recommendations, which to my knowledge have never been previously raised by Staff. I also note that AECC, FEA and Kroger all support APS's production cost-allocation method. I will discuss APS's opposition to these two changes to the COSS in more detail below.

Q. PLEASE DESCRIBE THE A&E METHOD.

A. APS uses the A&E method for allocating production demand costs, which uses a combination of peak demand and annual energy information to estimate the cost responsibility for each class. This method separates demand into two components: average demand and excess demand. The combination of both components is used to determine the share of production demand costs that are allocated to each class. Average demand is derived by calculating the average hourly demand for each hour of the year for each class. This conceptually reflects a base level of demand that drives the costs for baseload power plants. Excess demand is determined by the amount of Non-Coincident-Peak (NCP) demand that is above (in excess of) the average demand for each class. This component conceptually reflects the cost driver for peaking power plants. This method is conceptually valid and widely accepted in the industry. Intervenors Kroger, AECC and FEA support this allocation method, while Staff proposes an alternate method.

Q. WHY DOES STAFF WITNESS DISMUKES PROPOSE AN ALTERNATIVE METHOD?

A. Staff witness Dismukes claims that the A&E method is erroneous because it uses NCP information rather than coincident-peak (CP) information to allocate the excess demand costs.[4] Staff witness Dismukes proposes an alternative method called the average-and-peak allocator.

Q. DOES STAFF WITNESS DISMUKES IDENTIFY ANY COMPELLING REASON TO CHANGE PRODUCTION DEMAND ALLOCATION METHODS?

A. No. It has been commonly understood for decades that, under the A&E method, the class NCP must be used to allocate the excess component because if class CP information is used, the allocator mathematically reduces into a pure one CP allocator, which would not meet the ACC's desire for a production demand allocator that includes both demand and energy information. The A&E method is widely accepted as an appropriate method for allocating production demand costs, particularly when there is a desire for an allocation based on both demand and energy characteristics. Notably, the proposal to change methodologies does not even lead to a significant change in the results of the COSS.

Q. WHAT DO YOU RECOMMEND CONCERNING STAFF'S PROPOSAL FOR A NEW PRODUCTION DEMAND ALLOCATOR?

A. APS recommends the Commission continue to use the A&E method for allocating production demand costs in APS's COSS for the following reasons:

- The current A&E method is conceptually valid;

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[4] Staff Direct Testimony of David Dismukes at 16-18.

- It is widely accepted in the industry and is supported by other intervenors in this proceeding;

- It has been widely approved by the ACC without objection in the last three APS rate cases, and it is currently used by TEP/UNSE;

- Staff has not provided any reason for making this change at this time; and

- The difference in the results of the two methods is not significant.

Q. DID PARTIES RAISE ANY OTHER ISSUES CONCERNING THE ALLOCATION OF PRODUCTION DEMAND COSTS UNRELATED TO THE USE OF A&E?

A. Yes. FEA witness Amanda Alderson raised a concern that some production demand costs are embedded in certain Purchased Power Agreement(s) (PPA(s)), which are allocated as energy costs in the COSS. FEA witness Alderson proposes that a portion of the PPA cost be reclassified as production demand-related cost rather than energy-related cost. As production demand costs, she suggests they be allocated using the A&E method, rather than with an energy allocator.

Q. WHAT ARE YOUR THOUGHTS ON ALLOCATING PPA CAPACITY COSTS USING THE A&E METHOD IN APS'S COSS?

A. I believe FEA witness Alderson raises a valid, if perhaps largely theoretical, concern. I say theoretical because there are little or no capacity costs inherent in current purchased power costs. However, as I discuss below, the Commission should direct APS to evaluate this in the COSS in its next rate case, rather than specifically incorporating this change into this rate case, primarily because APS is recommending a proportional allocation of the requested increase irrespective of the COSS results.

Q. PLEASE DESCRIBE THE DISTRIBUTION COST ISSUES RAISED BY OTHER PARTIES.

A. FEA believes that a portion of distribution costs should be considered to be customer-related versus demand-related costs, while Staff contends that secondary distribution costs should be allocated in a different manner. SWEEP/WRA argues that APS has included distribution costs in the customer cost category that are inappropriate.

Q. WHAT ARE DISTRIBUTION COSTS?

A. Distribution costs comprise a wide array of cost components associated with the construction, maintenance, and operation of the local power grid. This includes substations, the primary lines that deliver power from the substations to the customer transformer, and the secondary equipment, which includes the customer transformer and the service drop to the home. It excludes the transmission grid, which is the extra-high voltage lines and equipment that deliver power from power plants to the local distribution grid. It also excludes the meter and certain point-of-delivery equipment that are included in revenue cycle service costs, such as metering, meter reading, billing, etc.

Q. WHAT IS FEA'S ISSUE CONCERNING DISTRIBUTION COSTS?

A. As I stated above, to make the COSS more transparent, costs are sorted or classified into broad categories that reflect general cost drivers, such as demand, energy and customer. FEA claims that a significant portion of the primary and secondary distribution costs, including, among other things, distribution lines and poles, should be reclassified as customer-related versus the demand-related classification used in APS's COSS.

Q. WHY DOES FEA MAKE THIS CLAIM?

A. FEA contends that a certain level of distribution equipment is needed to "hook-up" the customer to the grid, regardless of how much power they consume.[5] Therefore, this portion of distribution costs should be reclassified as customer-related costs.

Q. DO YOU AGREE?

A. Conceptually, yes. While I do not necessarily agree with all the details of FEA's claim and proposed solution, I do agree that a portion of distribution costs could reasonably be classified as customer-related costs. In fact, I believe it may go beyond the minimal system concept discussed by FEA.

Q. PLEASE EXPLAIN.

A. Certain distribution costs do not vary with the customer's monthly peak demand or their monthly energy usage. They may be sized to accommodate a maximum demand from the customer, but once installed, they do not vary with the customer's monthly load. Furthermore, some of these costs are dedicated to either individual customers or a small group of customers. Therefore, any excess capacity from one customer, or small customer group, cannot be shared with or used to serve another customer. The customer line transformer and secondary service drop to the home are examples of these types of fixed customer distribution costs. These types of fixed distribution costs are appropriate to include in customer-related costs.

In addition, common overhead costs necessary to operate the grid, such as communication and control equipment or cybersecurity costs, are unrelated to a customer's monthly demand or energy. These types of common costs could also appropriately be considered customer-related costs.

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[5] FEA Direct Testimony of Amanda Alderson at 15.

Q. HAS APS MADE THESE ARGUMENTS IN A PRIOR RATE CASE?

A. Yes. APS discussed the customer cost issue in its last general rate case.[6] The discussion supported APS's proposal to increase basic service charges for residential and commercial customers.

Q. DID APS RECLASSIFY THESE DISTRIBUTION COSTS IN THE COSS IN THIS RATE CASE?

A. No. The main reasons to perform such a reclassification study are to support proposed increases to the monthly basic service charges or support significant differences in the proposed rate increase for various customer classes. APS is not proposing a cost of service based increase to basic service charges in this case, beyond the across-the-board increases to all charges. In addition, APS is proposing a proportional allocation of bill impacts to all customer classes in this case. Therefore, APS did not conduct a distribution reclassification study in this case.

Q. DOES APS AGREE WITH ALL OF FEA'S PROPOSALS ON THIS ISSUE?

A. No. FEA proposes that APS perform one of two specific studies in its next rate case and recompute the COSS in this case using a prescribed percentage cost reclassification. While I generally agree with FEA witness Alderson's concern, I do not propose to make a change to the COSS in this case for the reasons stated above. Furthermore, FEA's proposal for APS's next rate case limits the investigation to two specific methods. As discussed above, APS's thinking on this matter goes beyond the historical concepts embodied in FEA's analysis and proposal.

Q. WHAT DOES APS PROPOSE ON THIS ISSUE?

A. APS proposes the Commission direct APS to evaluate this issue in the COSS in APS's next rate case but not incorporate this proposed change in this case.

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[6] APS 2016 General Rate Case Direct Testimony of Charles Miessner at 31-32.

Q. DOES SWEEP/WRA WITNESS BAATZ ESSENTIALLY PROPOSE THE OPPOSITE ALLOCATION TREATMENT OF THESE COSTS AS PROPOSED BY FEA?

A. Yes. SWEEP/WRA witness Baatz argues a narrow definition of customer costs to justify lower customer charges. This is incorrect and will be addressed in more detail by APS witness Jessica Hobbick.

Q. WHAT IS STAFF WITNESS DISMUKES' ISSUE CONCERNING DISTRIBUTION COSTS?

A. Staff witness Dismukes contends that secondary distribution costs should be allocated with a different method than what APS used in its COSS.

Q. WHAT ARE SECONDARY DISTRIBUTION COSTS?

A. As discussed above, secondary distribution costs include the customer line transformer, which is the pad-mounted or pole-mounted transformer by a customer's home, the service drop to the home, and certain other point-of-delivery equipment.

Q. WHAT ARE THE COST DRIVERS FOR THESE COSTS?

A. Secondary distribution costs are typically driven by the kW power demands of individual homes or small groups of homes. The equipment is sized specifically for the location being served and cannot be used to serve the power needs in another neighborhood. As discussed above, some of these costs could be considered "fixed" costs and therefore could be classified as customer-related costs.

Q. HOW ARE THESE COSTS ALLOCATED BY APS IN THE COSS?

A. The secondary distribution costs are allocated by the SIM allocator, which uses the individual maximum demands of the homes or businesses for each customer class. This is consistent with the cost driver. This allocator adds together the individual peak demands for each customer each month. These individual demands will occur at different hours and days in a month, depending on the load pattern for each home.

Q. WHAT DOES STAFF WITNESS DISMUKES PROPOSE FOR THIS ALLOCATION FACTOR?

A. Staff witness Dismukes proposes to allocate these costs based on the NCP information, which is the composite demand for all customers in a class, on the same day and hour of the month. He suggests this is appropriate based on the purported observation that there is considerable load diversity among APS's customers.[7]

Q. DO YOU AGREE WITH MR. DISMUKES' PROPOSAL?

A. No. This proposal is contrary to the cost drivers for secondary distribution costs. The NCP demand allocator is used for distribution costs that are shared across a wide group of customers, such as substation costs and primary distribution lines. If a customer in one neighborhood reduces their load, this "freed-up" capacity can be used to serve another customer in a different neighborhood served by the same substation. However, this is not the case for secondary distribution that serves an individual customer or at most, is shared by a small group of customers. Therefore, it is not valid to allocate secondary distribution costs with total class NCP information.

Q. WHAT IS LOAD DIVERSITY?

A. Load diversity means that not all customers peak at the same time or day. Therefore, the composite peak demand for the whole class is less than the sum of the individual peak demands for each customer.

Q. IS DIVERSITY A VALID REASON FOR MR. DISMUKES' PROPOSAL?

A. No. The NCP is a composite peak demand for a large class of customers. There is significant load diversity among all of the customers in each class. This diversity reduces the combined costs for substation and primary distribution equipment for the class. This diversity does not reduce the costs of secondary distribution equipment

[7] Dismukes at 18.

for the class, which is sized to serve individual homes and cannot be shared with other homes or neighborhoods, despite the diversity of loads.

Q. WHAT DO YOU RECOMMEND ON THIS ISSUE?

A. I recommend that the Commission reaffirm the use of APS's current method for allocating secondary distribution costs in its COSS because the SIM allocator is reflective of the drivers for these costs. Staff witness Dismukes' proposal does not appropriately reflect the cost responsibility for each customer class and, therefore, should not be adopted.

Q. PLEASE ADDRESS AECC WITNESS HIGGINS' COSS CRITICISM.

A. The AZ Sun assets are APS-owned grid-scale solar facilities that were installed as part of approved renewable program plans as APS sought to achieve the ACC's Renewable Energy Standard and Tariff (REST) targets. These assets are 100% allocated to the retail jurisdiction and, like the $6 million in renewable costs recovered in base rates, should appropriately be included in the system benefits charge[8] cost category. The original $6 million in renewable program costs has been categorized as system benefits since its inception. The remainder of the costs were in the REST. The AZ Sun assets were transferred to base rates in the most recent rate case prior to this one and were just categorized incorrectly. In this case, APS corrected this error. AECC witness Higgins disagrees. However, I believe this is simply because AG-X customers must pay the system benefits charge but not the unbundled generation charge. APS believes that all customers, including those AECC represents, should pay for the AZ Sun renewable assets. AG-X customers should not be excluded from this charge.

[8] As defined by the Commission in A.A.C. R14-2-1601.41, system benefits include Commission-approved renewable programs such as the AZ Sun program. APS's proposed treatment of AZ Sun assets is consistent with the Commission's System Benefit Charge requirements in A.A.C. R14-2-1608.

Q. WOULD ADOPTING ANY OF THESE CHANGES IN THE CURRENT COSS IMPACT APS'S PROPOSED RATE INCREASES.

A. No, even if allocation factors were changed in the COSS that created different results, APS still believes it is appropriate to use a proportional allocation of the overall bill impact to all classes of customers.

C. *Solar Advocates' Criticisms of the Company's COSS*

Q. PLEASE ADDRESS SEIA WITNESS LUCAS' CRITICISM.

A. SEIA witness Lucas' criticism is an attempt to re-litigate findings in the Commission's Cost and Value of Solar (VOS) Decision No. 75859. For example, the VOS decision found that residential solar customers should be evaluated as a separate class in a COSS, not analyzed as part of the overall residential class as recommended by SEIA. Also, in the VOS docket and in APS's last rate case, APS provided significant testimony justifying why the appropriate allocation method for rooftop solar customers should be based on site load and then the appropriate credits should be provided based on what costs solar customers actually offset. SEIA proposes this should be done using the delivered load[9], however, this method would require other costs be added back in for the services the rooftop solar customer is still receiving but no longer paying for in rates.

Q. DOES SEIA WITNESS LUCAS HAVE OTHER CRITICISMS OF APS'S COSS?

A. Yes, he does. All are invalid.

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[9] SEIA witness Lucas conflates statements in the VOS decision referring to export energy and the successor program to net metering to support this position. Rather, this was in contrast to a buy-all/sell-all approach. Decision No. 75859, page 146 stated, "The record in this proceeding demonstrates that rooftop solar customers are partial requirements customers who export power to the grid, and we therefore find that rooftop solar customers are a separate class of customers."

Q. PLEASE EXPLAIN.

A. SEIA witness Lucas alleges APS COSS model is not transparent. However, it is a Microsoft Excel spreadsheet-based model. In addition, there was also a meeting held by APS to demonstrate the tool. SEIA is the only witness to raise this concern in this case.

SEIA's criticism is founded on a concern that APS did not provide everything back to the source, but that is simply not true. The model incorporates values from APS's accounting system as the starting point, and all that detail is included in the model. APS's audited financials are the source of all numbers in the model. The COSS model does not allow SEIA to audit APS's financial accounting system (which is already audited by an independent accounting firm), but then that is not its purpose. SEIA had access to APS's FERC Form 1 for 2018 and 10-Qs for the first and second quarter of 2019 to complete the Test Year if SEIA wanted to independently verify revenues from retail rates.

SEIA's transparency complaint results from the desire to allocate costs to residential solar customers using delivered load. SEIA's desire to manipulate the COSS model to incorporate this incorrect assumption is not an indication that the model is not transparent. Further, SEIA alleges APS is bound by a finding in a UNS Electric (UNSE) decision regarding the use of a residential subclass NCP for cost allocation to rooftop solar customers. APS has a much higher adoption rate of rooftop solar in the overall residential customer class than UNSE. The finding in the UNSE decision is specific to UNSE. APS's method is appropriate for APS, given its unique circumstances.

Q. PLEASE ADDRESS SEIA'S CRITICISM OF APS'S USE OF SITE LOAD IN THE COSS IN MORE DETAIL. HOW DID YOU DETERMINE IT WAS APPROPRIATE TO CREATE A SEPARATE RESIDENTIAL SUB-CLASS FOR RESIDENTIAL ROOFTOP SOLAR ENERGY AND DEMAND CUSTOMERS WITHIN THE RESIDENTIAL CUSTOMER CLASS?

A. It can be appropriate to create a new class or sub-class of customers for purposes of a COSS or setting rates if the service, load, or cost characteristics of the customer sub-group in question are sufficiently different from their current customer classification. Upon reviewing these characteristics for customers with solar, APS determined that sufficient differences exist for creating this sub-class of residential customers. That was true in the VOS docket, and it is even more true now. When evaluating the load characteristics of residential customers with and without rooftop solar, the peak demand – CP, NCP and SIM – and energy characteristics are very different for solar customers. In the Test Year, the average residential solar customer still needs about 74% of the capacity they used before they adopted solar and 37% of the energy. This is a significantly different profile than residential customers without solar, regardless of size.

APS had nearly 76,000 grandfathered residential solar customers and over 15,000 residential solar customers on the new Resource Comparison Proxy export rate by the end of the Test Year. The size of this residential solar customer sub-group combined with its vastly different load characteristics, warrant evaluating them as a separate sub-class which, again, was determined in the VOS.

Q. PLEASE EXPLAIN THE PROCESS THAT APS USED TO CREATE A UNIQUE RESIDENTIAL SUB-CLASS FOR RESIDENTIAL ROOFTOP SOLAR CUSTOMERS.

A. Consistent with the methodology I previously discussed:

- APS grouped residential solar customers currently on energy-based rate schedules, which includes customers both on inclining block and TOU rate schedules;
- APS separately grouped residential solar customers on demand-based TOU rate schedules;
- APS used the data for the residential solar customer's entire load at the home – load served both by APS and the customer's rooftop solar system – as the starting point for cost allocation to develop the CP, NCP, and SIM demand allocations, as well as the energy allocations;
- APS then explicitly credited the customer for:
    - All their self-provided production capacity based on a comparison to the APS-delivered customer load using both the four summer sub-class CPs and NCPs;
    - Their entire energy production, including both what the customer consumes on-site and what is delivered from the residential solar customer to the grid;
    - The avoided transmission cost based on a comparison to the APS-delivered customer load at the time of the four summer CPs;
    - The avoided primary distribution cost based on a comparison to the APS-delivered customer load at the time of the four summer sub-class NCPs; and
    - The avoided secondary distribution cost based on a comparison to the APS-delivered customer load at the time of the four summer sub-class SIMs.

This approach fully credits residential solar customers for all cost savings resulting from the capacity (production, transmission, and distribution) and energy supplied to the grid by their rooftop solar systems. The result is that the COSS analysis only allocates capacity and energy costs to residential solar customers based on what APS must provide. This analytical approach also captures the cost of providing grid services for the rooftop solar customer's export of energy and backup of the customer's self-supplied generation, including support for the starting of motors (*e.g.*, the inrush current associated with the starting of an air conditioning unit, which cannot be met by a solar array).

Q. BY USING A RESIDENTIAL SOLAR CUSTOMER'S ENTIRE LOAD AT THE HOUSE AS A STARTING POINT, AREN'T YOU CHARGING FOR SERVICES APS DOES NOT PROVIDE?

A. No, in fact, the exact opposite is true. It is true that APS does not supply the energy service when a residential solar customer's self-generation is supplying energy. But, the crediting process described above fully accounts for the customer's self-supply of this energy service. Moreover, although the residential solar customer supplies some of their own energy, APS continues to supply a host of backup and ancillary services that in turn require APS to build, operate, and maintain the bulk of its fixed infrastructure required to serve that residential solar customer. Beginning with a residential solar customer's entire site load and then explicitly crediting to that customer the value of the energy and capacity that they supply from their own rooftop solar system is the only transparent way to balance the benefits provided by rooftop solar systems on residential rooftops and the costs required to continue serving those customers with rooftop systems.

Q. PLEASE EXPLAIN FURTHER HOW THIS APPROACH COMPENSATES RESIDENTIAL SOLAR CUSTOMERS FULLY FOR THE BENEFITS THEY PROVIDE TO APS.

A. By comparing the entire load at the home to the remaining household load served by APS, we can determine the infrastructure that APS no longer needs to provide as a result of the solar system. Although a solar installation will have a certain maximum-production capability, that capability will only be realized at midday and only on sunny days. The load information reveals what actually occurred when the customer was consuming energy in contrast with the solar production at the same time. The alignment between when a residential customer needs power and when the solar system operates is not significant in APS's service territory. APS's peak loads persist in the summer months beyond sunset, and the maximum peak load occurs closer to sunset than midday.

The appropriate level of compensation for offsetting demand-driven infrastructure costs should be based on how effective the residential solar customer's solar system is at offsetting APS's peak loads. For example, the COSS indicates for a residential solar customer, the appropriate level of production demand credit is 26.3%, transmission capacity credit is 36.4%, distribution primary and substations capacity credit is 16.2% and distribution secondary capacity credit is 20.4%.

Likewise, the energy compensation in a COSS should reflect the actual fuel costs that APS avoids when a solar customer consumes less energy. The method described above uses the filed avoided fuel costs for all kWh produced by the rooftop solar system, which is a conservative proxy for the actual costs saved by APS.

Q. SEIA WITNESS LUCAS IS CRITICAL OF APS'S LOAD RESEARCH CENSUS AND HOW THAT DATA IS EXTRAPOLATED INTO OVERALL FERC FORM 1 SALES INFORMATION. IS THIS A VALID CRITICISM?

A. Absolutely not. APS's load research approach is superior to most utilities that still primarily use a load research sample and extrapolate that data into FERC Form 1 sales information. A utility has to start with actual sales in the Test Year. And any load research sample will require a method to convert the sample data into the full picture. APS's load research census uses customers' data if their interval data lines up with their billing meter reads and 100% of intervals for the 24-hour period are recorded. The information is then used in calculating the average customer for the day. Based on this method, APS has on average 1,065,132 customers in the census sample, versus a more typical load research sample of approximately 2%. Again, this criticism stems from SEIA's desire for the data to reflect delivered load for solar customers.

Q. SEIA ALSO MAKES REFERENCE TO A REGULATORY ASSISTANCE PROJECT (RAP) MANUAL ON COST ALLOCATION. DO YOU HAVE A PERSPECTIVE ON THE RAP MANUAL?

A. Yes, I do. The Regulatory Assistance Project (RAP) is not an unbiased industry consulting or academic group trying to revise cost allocation theories to improve the evaluation of distributed resources, as SEIA suggests. Rather, it is an advocacy group for energy efficiency and distributed solar resources. RAP's mission, as they clearly state, "is dedicated to accelerating the transition to a clean, reliable, and efficient energy future."[10] Therefore, their opinions should be viewed similarly to SEIA's – as an advocacy group offering viewpoints that seek to support their cause and benefit customers that adopt their preferred technologies. Similarly, the RAP

[10] Regulatory Assistance Project website home page, https://www.raponline.org/.

Manual should be considered to be an advocacy white paper, rather than a neutral how-to guide for utility cost studies.

Q. SEIA WITNESS LUCAS ALSO CLAIMS RESIDENTIAL ROOFTOP SOLAR CUSTOMERS ARE NO DIFFERENT THAN NON-SOLAR CUSTOMERS. IS THIS CORRECT?

A. No, it is not. As I indicated above, they are significantly different in their energy use characteristics. This claim was effectively debunked in the VOS docket, which is what led to the finding that rooftop solar customers should be evaluated as a separate class in a COSS because partial requirements customers are fundamentally different in their usage of the grid than full-requirements customers regardless of size.

Q. WHAT IS DELIVERED LOAD?

A. The electrical load of a solar customer can be separated into three components: 1) the total house load, or site load; 2) the portion of the site load that is served by the solar generator; and 3) the residual load that is served by the utility. The latter is referred to as "delivered" load.

Q. WHAT DOES SEIA WITNESS LUCAS CLAIM CONCERNING DELIVERED LOAD?

A. As I discussed above, SEIA witness Lucas asserts that the delivered load is the only portion that should be included in a COSS or any other type of economic evaluation of distributed solar generators. SEIA equates a solar generator to a cooktop or any other type of appliance, which would not require or warrant any special treatment in a COSS.[11] SEIA asserts that for either an appliance or a generator, the utility is only responsible for, and only incurs costs for, serving the delivered load.[12]

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[11] SEIA Direct Testimony of Kevin Lucas at 24.
[12] Lucas at 23.

Q. DO YOU AGREE?

A. No. An on-site generator is fundamentally different than an appliance, both in terms of the service requirements for a utility and the costs for those services. That is the entire point of my earlier discussion on why solar customers are separated into a distinct customer class in the COSS and why a different method is needed for assessing the costs for the solar class.

Q. PLEASE EXPLAIN.

A. Customers with on-site generation, also referred to as partial requirements customers, have always warranted special rate treatment. Because the customer generates their own power and potentially exports power to the grid, special rate provisions are necessary to compensate the customer for the exported power, provide backup service for the generator, and to appropriately recover the costs of the grid services provided by the utility. These services go well beyond the simple cost of service for the delivered load claimed by SEIA witness Lucas.

Q. PLEASE CONTINUE.

A. Because of APS's increased responsibilities and costs for serving partial-requirements customers, the Commission has authorized special rate provisions and programs for these customers for decades. In the last rate case, the legacy residential net metering program which incented the early adoption of solar generation, was frozen because it over-compensated solar customers for the exported power, did not adequately recover costs for providing backup service, and significantly under-recovered the costs for the grid services provided by the utility. These issues, coupled with the explosive growth in solar adoption, resulted in the potential for over $1 billion of under-recovered costs to be shifted to other residential customers.

Q. SEIA WITNESS LUCAS ALSO CLAIMS THAT THIS COST EVALUATION SHOULD BE BASED ON MARGINAL COSTS. DO YOU AGREE?

A. No, not generally in a rate case evaluation. While certain rate design issues can be informed by marginal costs, such as the magnitude of monthly service charges or the TOU price ratios, a rate case is fundamentally focused on the recovery of average, embedded costs for a historic test year. Therefore, the compilation and allocation of costs in a COSS and the reflection of those costs in rate design primarily involves embedded cost, rather than marginal cost, information. While a new approach is needed for evaluating solar customers and appropriately reflecting the additional costs to serve them, as I have outlined above, those costs should generally use test-year embedded cost information.

Q. LASTLY, SEIA WITNESS LUCAS OBJECTS TO THE METHOD FOR ALLOCATING GENERATION COSTS TO SOLAR CUSTOMERS. WHAT ARE YOUR THOUGHTS?

A. APS evaluates the generation capacity costs, also referred to as production capacity, for serving solar customers by first allocating those costs to the solar classes based on the site load using the A&E method, similar to other residential classes, and then crediting the service cost reduction attributable to the solar generator based on coincident peak and non-coincident peak information. Mr. Lucas claims that this approach is internally inconsistent and, therefore, incorrect.

Q. DO YOU AGREE?

A. No. SEIA witness Lucas offers no reasoning, other than that the two methods are different, to support his conclusion. In fact, two different allocation methods are needed to accurately reflect the cost impacts for production capacity for customers with on-site generation. The A&E method reflects the overall generation costs needed to serve the entire site load, from APS's entire portfolio of power plants – including baseload nuclear and coal plants to peaking natural gas plants. However, the capacity cost savings from adding solar generation is more appropriately assessed using an allocator that reflects the specific capacity impacts provided from on-site generation, which are driven by the availability of the generator at the time of APS's system peaks.

This two-method allocation approach is conceptually the same as the cost studies that support the partial-requirements rates for general service customers. For those rates, the customer's unbundled generation charges in their base rate is based on a general A&E cost allocator, while the specific rates for the services needed to back up and support the on-site generation are based on the generator's peak impacts.

X. GENERAL SERVICE RATE DESIGN

Q. DID YOU REVIEW THE COMMENTS OF OTHER PARTIES CONCERNING APS'S GENERAL SERVICE RATES?

A. Yes. SEIA was the only party that provided comments and proposals on APS's general service rates. They propose several changes to the general service E-32 rates, which include: 1) removing the declining block demand and energy structure; 2) removing the demand ratchet for rate E-32 L,[13] 3) changing the demand charge for rate E-32 S; and 4) restructuring all of the rates so that high load factor customers on the border of two rates can achieve a higher bill savings when they reduce their demand.[14]

Q. WHAT IS YOUR GENERAL RESPONSE TO SEIA'S PROPOSALS?

A. APS opposes each of SEIA's proposals because they do not appropriately reflect the cost of service for these customer classes. Instead, they unjustifiably favor customers that adopt SEIA's favored technologies and shift costs to other customers by raising their rates and bills. APS believes that rates should be technology

[13] Lucas at 116.
[14] Lucas at 120.

agnostic; the bill savings from adopting a certain technology should be commensurate with the cost savings provided back to the grid. APS's commercial rates, as presently designed, do a good job of addressing this important objective. SEIA's proposals do not. They essentially create a subsidy for certain technologies, while shifting costs to other customers. I note that no commercial customer or group that represents commercial customers are offering any similar proposals.

Q. LET'S FIRST DISCUSS THE DECLINING BLOCK DEMAND CHARGE.

A. Sure. Because the E-32 rates serve a wide variety of customers with different demands and usage characteristics, the unbundled distribution charges are separated into two components. The first component recovers a basic level of distribution service for "hook-up" costs and other general costs, some of which could alternatively be recovered through a monthly customer charge. The charge for this tier is applied to a customer's first 100 kW of demand each month. The second component recovers additional distribution costs that increase as a customer's load increases. The charge for this tier, which is lower than the first-tier charge, is applied to the customer's monthly demand above 100 kW. As a result, larger customers are charged a lower average demand rate than smaller customers, which reflects their lower average cost of service.

Q. WHY DO THINK SEIA WITNESS LUCAS IS PROPOSING TO ELIMINATE THIS RATE FEATURE?

A. Undoubtably, eliminating this feature would potentially increase the avoided demand charge for larger customers that might consider adopting certain technologies that target demand reduction, such as behind-the-meter solar plus storage. I also note that SEIA'S proposal would also, without intention, decrease the avoided demand charge for smaller customers who seek to adopt similar demand-reducing technologies.

Q. WHAT DO YOU RECOMMEND?

A. SEIA's proposal should be rejected because it is not reflective of cost of service. This feature helps ensure the rate can be used to serve a wide variety and size of commercial customers.

Q. NOW LET'S DISCUSS THE ENERGY CHARGES FOR RATES E-32 S AND E-32 M, WHICH SEIA OPPOSES.

A. Rate E-32 S serves small-sized general service customers with monthly demands of 21 to 100 kW, while E-32 M serves medium-sized commercial customers with monthly demands of 101 to 400 kW. The unbundled generation charges for both rates have a unique design called a "load-factor" or "times-use" rate structure. It is not, strictly speaking, a declining block energy rate, as SEIA states, but rather a rate structure that combines a demand charge and energy charge into a single rate component.

Q. PLEASE EXPLAIN.

A. The unbundled generation charges for general service rates typically include two components – a demand charge, which recovers the capacity cost of generation power plants, and an energy charge, which recovers the cost of fuel and variable O&M. The load factor design uses a two-tiered energy charge design and incorporates the demand charge into the first-tier energy charge. In addition, the tiers are based on a certain amount of kWh usage per unit of kW demand, instead of merely being a traditional declining-block energy rate, as referenced by SEIA witness Lucas, in which the tiers are based on total kWh usage.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. Consider a customer served under the E-32 M rate that uses 110,000 kWh and 300 kW in a month. The billing units, unbundled generation rates for the two kWh tiers and billed amounts, are shown in Table 2 below, under "current rate design." The tier 1 kWh energy charge applies to 200 kWh per kW or 60,000 kWh (200 X

300). All of the additional 50,000 kWh are billed under the tier 2 energy charge. The charges for each tier recover $0.04965 per kWh of energy-related costs. The Tier 1 charge also recovers $0.04103 per kWh of generation capacity costs, which is the Tier 1 energy charge minus the Tier 2 energy charge.

Q. WHAT WOULD THE RATE BE IF IT USED A DEMAND CHARGE INSTEAD OF THE TIMES-USE APPROACH?

A. If the rate were redesigned to recover the generation capacity costs through a kW demand charge, instead of through an embedded kWh load-factor tier, the demand charge would equal $8.206 per kW, which is the $0.04103 per kWh of embedded capacity charge in Tier 1 converted to a kW charge by multiplying it by 200 kWh ($8.206 = $0.04103 X 200 kWh). This conversion is displayed below in Figure 1 below. Please note that these alternative charges are illustrative – they would have to be adjusted slightly to assure that the resulting revenue is neutral for the entire E-32 M customer class.

Figure 1. Unbundled Demand Charge for Rate E-32 M Summer Month

Tier 1 kWh	$	0.09068
Tier 2 kWh	$	0.04965
Demand Component	$	0.04103
Converted to kW charge	$	8.206

Q. WOULD THE BILL BE THE SAME UNDER BOTH RATE DESIGNS?

A. Not necessarily. The example shown in Table 1 results in the same monthly bill under either rate design. However, this result will vary according to the actual customer's load patterns and the comparative amount of energy and demand consumed in a month. Some customers would pay more under the alternative design, others would pay less.

Table 2. Rate E-32 M, Proposed Unbundled Generation Rates (Summer)

Currently Proposed Rate Design

	Units	Rate	Bill
Tier 1 kWh	60,000	$ 0.09068	$ 5,440.80
Tier 2 kWh	50,000	$ 0.04965	$ 2,482.50
			$ 7,923.30

Alternative Rate Design

	Units	Rate	Bill
kW demand	300	$ 8.206	$ 2,461.80
kWh energy	110,000	$ 0.04965	$ 5,461.50
			$ 7,923.30

Q. **HAVE ANY CUSTOMERS OR CUSTOMER GROUPS RECOMMENDED THIS CHANGE?**

A. No. The current rate design fairly recovers generation capacity costs from a rate class that has a wide range of customer sizes and usage patterns.

Q. **WHAT DOES APS RECOMMEND FOR RATES E-32 S AND E-32 M?**

A. Conceptually, APS does not oppose converting the unbundled generation charges in rates E-32 S and E-32 M from a load-factor-based design to a traditional demand and energy charge design. However, APS does not support this rate change at this time because SEIA witness Lucas has not provided any compelling reasons for making this change, no customer groups are proposing this change, and the change would create disparate bill impacts for customers, which have not been investigated.

In addition, APS would be opposed to simply combining the two tiers of energy charges into a simple average kWh rate, without converting the embedded demand component into a demand rate. Combining the two energy charges into a single rate would simply recover all of the generation capacity costs through a kWh rate, which would not be reflective of the cost of service and would be a flawed approach to rate design.

Q. WHAT DOES SEIA PROPOSE CONCERNING THE DEMAND RATCHET FOR RATE E-32 L?

A. SEIA proposes to eliminate this feature of the rate.[15]

Q. WHY IS SEIA PROPOSING THIS CHANGE?

A. Again, this proposal is self-serving for SEIA. It seeks to increase the economic benefit for customers who adopt certain technologies supported by SEIA, while raising the demand rates and bills for other customers.

Q. HOW WOULD SEIA'S PROPOSAL INCREASE THE RATES FOR CUSTOMERS THAT DO NOT ADOPT SEIA'S PREFERRED TECHNOLOGIES?

A. The demand ratchet feature is a cost-based rate component that helps to match the demand component of each customer's bill with their actual cost of service. If the demand revenue for some customers is unjustifiably reduced, the costs will be shifted to other customers in the same class through higher demand rates.

Q. WHAT IS A DEMAND RATCHET?

A. A demand ratchet is a rate feature that seeks to fairly recover a customer's demand costs through monthly demand charges, even though the costs are primarily driven by the customer's demand in the core summer months. The demand charges could alternatively be applied only to the summer bills, but that would result in very uneven monthly bills, which would be very high in the summer. In addition, some demand-related costs are driven by a customer's demand in all months of the year.

[15] Lucas at 116.

Q. ARE RATCHETS COMMONLY USED IN THE UTILITY INDUSTRY?

A. Yes. Demand ratchets are a common feature in rates for large and extra-large commercial and industrial customers across the utility industry.

Q. HOW DOES A RATCHET WORK?

A. On each monthly bill, the customer pays the higher of their actual metered demand or 80% of the highest demand in the previous summer. If a customer has a relatively steady load throughout the months, the ratchet would have no impact. If the customer's demand falls off significantly in the winter months, the ratchet would ensure that the demand-related costs would be recovered from that customer, and not shifted to other customers.

Q. DOES APS SUPPORT SEIA'S PROPOSAL TO ELIMINATE THE RATCHET?

A. No. SEIA has not provided any compelling reason for eliminating the ratchet feature. SEIA's proposal is simply self-serving and unjustifiably shifts costs to customers that do not adopt their preferred technologies. In addition, I note that no customers or customer groups are proposing this change.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON SEIA'S PROPOSALS ON GENERAL SERVICE RATES.

A. APS does not support any of SEIA's proposals for general service rates. SEIA does not offer any valid reasons for making these changes. They are simply self-serving and seek to advantage customers that adopt their preferred technologies and shift costs to other customers by increasing demand charges and bills. In addition, no customers or customer groups are proposing these changes.

Q. WHAT DOES SEIA PROPOSE FOR APS'S E-32 L STORAGE PILOT RATE?

A. SEIA proposes to modify the E-32 L Storage Pilot rate by eliminating the minimum storage requirement, changing the on-peak hours to 2-6 p.m., and changing the demand charge structure for on-peak and "remaining" hours.[16]

Q. DID SOLAR PARTIES DEVELOP AND PROPOSE THIS RATE?

A. Yes. SEIA contends that the storage pilot rate was designed by APS.[17] However, this is incorrect and misleading. In fact, the E-32 L Storage Pilot rate was proposed by solar parties as part of APS's last rate case and ultimately approved by the Commission. They patterned the rate after a storage rate from another utility.

Q. THEN WHY IS SEIA SEEKING TO SIGNIFICANTLY CHANGE THE RATE AT THIS TIME?

A. Presumably, the solar parties' previous rate design was ineffective at driving the adoption of storage technology.

Q. DO YOU AGREE WITH SEIA'S PROPOSED MODIFICATIONS?

A. APS agrees to further investigate the storage rate issue, but we do not necessarily agree with SEIA's proposals; some are invalid and should not be adopted, and others will require further investigation.

Q. PLEASE EXPLAIN.

A. The proposal for a 2 p.m. to 6 p.m. on-peak period does not reflect the critical hours on APS's system and is only self-serving to promote distributed solar. This issue is further discussed in the Rebuttal Testimony of APS witnesses Hobbick and Albert. Therefore, this proposal should be rejected. In addition, SEIA's proposal to eliminate the requirement that a customer adopt energy storage to qualify for the rate should be rejected. The suggestion is nonsensical; why in the world would you ever develop an energy storage rate that does not require energy storage? Furthermore,

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[16] Lucas at 130-31.
[17] Lucas at 121.

APS believes that a reasonable minimum storage requirement is appropriate to prevent a customer from "gaming" the rate schedule by installing a de minimis amount of storage technology.

However, the Company believes that the demand-rate structure and other rate-design components can be investigated as long as they are reflective of cost of service and not just intended to advantage customers that adopt energy storage at the expense of other customers.

Q. ASBA/AASBO HAVE PROPOSED SEVERAL CHANGES. PLEASE DISCUSS THEIR RECOMMENDATION REGARDING THE SCHOOLS TOU RATES.

A. ASBA/AASBO propose to modify the Schools TOU rate, which presently has three seasons (Winter, Summer, and Summer Peak) and three time periods (On-Peak, Off-Peak, and Shoulder-Peak). They propose to eliminate the Shoulder-Peak time period and use the off-peak price for those shoulder hours. While APS is not opposed to removing the shoulder-peak price, the off-peak price would also have to be revised to ensure that the change was revenue neutral. However, if parties desire to change the Schools TOU rate, I would recommend to further revise the rate beyond what is described by ASBA/AASBO witness Travis Sarver, to be more consistent with other general service and irrigation rates. Such revisions could include, for example, changing the on-peak period to be 3 p.m. to 8 p.m., Monday through Friday, and reviewing the appropriateness of the three seasons in the Schools TOU rate.

Q. WOULD THESE TYPES OF RATE REVISIONS CREATE DISPARATE BILL IMPACTS FOR INDIVIDUAL SCHOOLS?

A. Yes. If the Schools TOU rate were revised by either ASBA/AASBO's proposal or by the further modifications I have discussed, the changes would result in disparate bill impacts for individual schools. Some bills would increase, others would decrease beyond the impact of the general revenue change authorized in this proceeding.

Q. ASBA/AASBO ALSO PROPOSES TO ALLOW SCHOOLS WITH SOLAR TO USE THE RESOURCE COMPARISON PROXY (RCP) AS AN ALTERNATIVE TO NET METERING. DO YOU SUPPORT THIS SUGGESTED CHANGE?

A. No, I do not support this change. The VOS proceeding was about addressing the cost shift resulting from net metering for residential rooftop solar customers. The result was the RCP method for energy that is exported to the grid, at any time, and using the retail rate to offset self-consumption. Schools still have the ability to net meter, and the VOS decision and resulting RCP for export energy is simply not applicable to schools.

Q. IN ADDITION, ASBA/AASBO PROPOSES SCHOOLS BE ALLOWED TO AGGREGATE THEIR METERS ACROSS THE SCHOOL DISTRICT. WHAT ARE YOUR THOUGHTS ON THIS?

A. APS strongly opposes this aggregation recommendation. APS presently allows a school to totalize its loads on a contiguous campus in accordance with its Service Schedule 4 - Totalized Metering of Multiple Service Entrance Sections at a Single Site. This form of totalization is reasonable. However, aggregating loads across a school district is not appropriate. Each campus location has different electric infrastructure. The specifics of cost causation, cost allocation, and the design of rates takes this into account. A campus can be considered a unique customer, but a customer with multiple locations constitutes many customers. It is inappropriate to aggregate school loads across a district that has multiple school campuses. Lastly, the proposed rates and charges are designed to collect the targeted revenue without aggregation. ASBA/AASBO witness Sarver has a simple example where he illustrates the benefits of aggregation but ignores that fact that the rates would have to be redesigned to collect the target revenue – essentially reclaiming his computed savings.

XI. CONCLUSION

Q. WHAT CONCLUSIONS DO YOU HAVE BASED ON YOUR REBUTTAL TESTIMONY?

A. The Commission should approve APS's conservative fair value rate of return. The mechanics of the calculation are based on those proposed by ACC Staff and adopted by the ACC in the 2007, 2010 and 2015 test year rate filings made by APS that resulted in Decision Nos. 71448 (Dec. 30, 2009), 73183 (May 24, 2012), and 76295 (Aug. 18, 2017).

The Commission should approve APS's proposed AEM.

The Commission should approve APS's COSS that is used to support the Company's rate design in the Company's application, as well as the jurisdictional allocation of costs.

Lastly, the Commission should reject intervenors' proposals regarding the AG-X /AG-Y programs and approve APS's new rate rider proposal AG-Y. The Commission should reject SEIA's and ASBA/AASBO's recommendations regarding general service rate design.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Calculation of Fair Value Increment

	Adjusted Test Year Capital Structure	Amount	%	Cost Rate	Weighted Avg
1.	Long-Term Debt	$ 4,726,125	45.33%	4.10%	1.86%
2.	Preferred Stock	-	0.00%	0.00%	0.00%
3.	Common Equity	5,700,968	54.67%	10.00%	5.47%
4.	Short-Term Debt	-	0.00%	0.00%	0.00%
5.	Total	$ 10,427,093	100.00%		7.33%

	Capital Structure with 1.0% FV Increment	Amount	%	Cost Rate	Weighted Avg
6.	Long-Term Debt	$ 4,032,678	32.75%	4.10%	1.34%
7.	Preferred Stock	-	0.00%	0.00%	0.00%
8.	Common Equity	4,863,590	39.49%	10.00%	3.95%
9.	Short-Term Debt	-	0.00%	0.00%	0.00%
10.	FVRB Increment	3,418,936	27.76%	0.80%	0.22%
11.	Total	$ 12,315,204	100.00%		5.51%

	Fair Value Increment Calculation	Fair Value	Original Cost
12.	Rate Base	$ 12,315,204	$ 8,896,268
13.	Rate of Return	5.51%	7.33%
14.	Required Operating Income	$ 679,050	$ 652,096
15.	Adjusted Operating Income	648,726	648,726
16.	Adjusted Operating Income Deficiency (line 14 - line 15)	$ 30,324	$ 3,370
17.	Revenue Conversion Factor	1.3346	1.3346
18.	Increase in Base Revenue Requirements (line 16 * line 17)	$ 40,470	$ 4,497
19.	Fair Value Increment	$ 35,973	
20.	RCND Rate Base	$ 15,734,140	

Advanced Energy Mechanism (AEM) Plan Cost Recovery
Term Sheet

Purpose	To provide for timely cost recovery of the capital carrying cost and expense of APS clean energy plan investment, including energy efficiency (EE) expenses, and lost fixed costs associated with EE and distributed generation (DG) revenue requirements which are not already recovered in base rates or through another Arizona Corporation Commission (Commission) approved adjustment. Clean energy resources are defined as non-carbon emitting resources but excludes nuclear energy.
Authorization	Integrated Resource Plan (IRP) Action Plan or Clean Energy Implementation Plan approval by the Commission and robust Request for Proposal (RFP) process – acquisitions that comply with the IRP Action Plan and RFP process. The IRP process would determine the prudence of the IRP Action Plan, and the process prescribed in Energy Rules would determine the prudence of the Clean Energy Implementation Plan.
Cost Recovery of APS Owned Resources, EE Investment and Coal Community Transition (CCT) Cost	An Advanced Energy Mechanism (AEM) will recover the capital carrying costs of approved clean energy plan investment, including APS-owned newly constructed or acquired plants, EE expenses, lost fixed costs associated with EE and DG revenue requirements and Coal Community Transition cost. The AEM process will determine prudence of APS's execution of the IRP Action Plan and Clean Energy Implementation Plan.
Lost Fixed Costs (LFC)	Lost Fixed Costs (LFC) recovered will be consistent with the current accounting for LFC. In future rate cases (not the current rate case), APS may propose changes to the LFC recovery accounting.
Cost Recovery of Resources Resulting from Purchased Power Agreements (PPA)	Purchase Power Agreement (PPA) resources will be recovered through the Company's Power Supply Adjustor (PSA), including storage PPAs. PPAs with recovery presently split between the Renewable Energy Adjustment Charge (REAC) and PSA would move completely to the PSA.
AEM Adjustor Process	Annual filing and implementation as specified in a Plan of Administration, including EE investment plan. In each rate case, the AEM will be reset and APS-owned resource investments will be moved into base rates.
Key Parameters of Capital Carrying Costs	Capital Carrying Costs consist of (1) Return on the Qualified Net Plant calculated based on the Company's Weighted Average Cost of Capital (WACC) approved by the Commission in its most recent rate case plus a return on the fair value increment (if any) for the Qualified Net Plant; (2) depreciation expense; (3) income taxes; (4) property taxes and (5) associated operations and maintenance expenses (O&M).
Year-over-Year Annual Adjustor Cap	The AEM will not increase by more than $0.005 per kWh in any annual adjustment process. Any amounts over the annual cap would be held over to a subsequent adjustment.
Balancing Account	The AEM will have a balancing account that will track revenues versus costs, as well as a true-up of budgeted to actual costs.
Earnings Test	As part of each filing, APS will file an earnings test based on the Commission's jurisdictional portion of the most recent FERC Form 1, with rate base, operating revenue and expense adjustments adopted in the most recent rate case. The earnings test will determine what portion of the AEM will be recoverable each adjustment cycle.

AEM Timing	Stakeholder Engagement (including EE plan and LFC forecast): February - May Filing: June 1 Effective: January 1
AEM Approval	ACC – Open Meeting
AEM Revenue Allocation	Equal across rate classes, kW charge for customers on kW rates, and kWh charge for customers on energy-only rates.
Other Adjustor Rates	APS retains all current adjustors: PSA, Transmission Cost Adjustment (TCA), Environmental Improvement Surcharge (EIS) and Tax Expense Adjustment Mechanism (TEAM), Lost Fixed Cost Recovery mechanism (LFCR), REAC and Demand Side Management Adjustment Clause (DSMAC). AEM will replace LFCR, REAC and DSMAC over time as they are reset in the future.
Adjustor and Base Rate Transfers	A revenue-neutral portion of REAC costs will be moved to base rates and the PSA. A revenue-neutral portion of DSMAC costs will be moved to base rates.