BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322 **NOTICE OF FILING REDACTED DIRECT TESTIMONY (COST OF SERVICE/RATE DESIGN) AND EXHIBITS OF KEVIN C. HIGGINS ON BEHALF OF FREEPORT MINERALS CORPORATION, ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION AND NOBLE AMERICAS ENERGY SOLUTIONS LLC**

Freeport Minerals Corporation, Arizonans for Electric Choice and Competition (collectively "AECC") and Noble Americas Energy Solutions LLC ("Noble"), hereby submit the Redacted Direct Testimony (Cost of Service/Rate Design) and Exhibits of Kevin C. Higgins on behalf of AECC and Noble in the above captioned Docket.

For the parties who have signed the Tucson Electric Power Company ("TEP") Protective Agreement, they will be able to view the confidential portion of Mr. Higgins' Testimony by accessing the TEP Rate Case Data Room site.

RESPECTFULLY SUBMITTED this 24th day of June, 2016.

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REDACTED

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport Minerals Corporation,

Arizonans for Electric Choice & Competition and

Noble Americas Energy Solutions LLC

Cost of Service/Rate Design

June 24, 2016

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who pre-filed direct testimony in this case on behalf of Freeport Minerals Corporation and Arizonans for Electric Choice and Competition ("AECC")[1] on the subject of revenue requirement?

A. Yes, I am. My cost of service / rate design testimony is also being sponsored by Noble Americas Energy Solutions ("Noble Solutions") with respect to my discussion of buy-through programs and related topics. Noble Solutions is a retail energy supplier that serves over 15,000 commercial and industrial end-use customers in 16 states, the District of Columbia, and Baja California, Mexico, and supplies power to Arizona Public Service Company ("APS") that serves Experimental Rate Rider AG-1 ("AG-1") customers on the APS system.

Q. What is the purpose of your testimony in this phase of the proceeding?

[1] Henceforth in this testimony, Freeport Minerals Corporation and AECC collectively will be referred to as "AECC."

A. My testimony addresses the general topics of cost of service, revenue allocation, and rate design. My testimony also includes specific discussions of the buy-through tariff presented by Tucson Electric Power Company ("TEP" or the "Company"), unbundled rates, the mobile home park rate schedule, the Lost Fixed Cost Recovery mechanism ("LFCR"), and rate design issues applicable to the Purchased Power and Fuel Adjustment Charge ("PPFAC").

SUMMARY

Q. What are the primary conclusions and recommendations presented in this phase of your testimony?

A. (1) As a general proposition, I support TEP's use of the 4CP – Average & Excess Demand ("4CP AED") method to allocate production demand and transmission costs to classes. However, I disagree with two details related to the Company's application of the 4CP AED method. Accordingly, I am recommending two specific changes to TEP's calculation of the 4CP AED allocator, which I describe in my testimony.

(2) I have identified five cost allocation errors and conceptual flaws in TEP's cost-of-service study unrelated to the allocation of generation and transmission costs, which I have corrected in my testimony. Two of these errors were acknowledged by TEP in discovery.

(3) TEP's proposed revenue allocation contains a very large subsidy for the Residential class, whereas the General Service ("GS") and Large General Service ("LGS") classes would have rates that are 16.7% and 25.0% above cost, respectively. *Using TEP's overall revenue proposal as a baseline*, I recommend

reducing the GS and LGS revenue allocation such that the rates for each class are no more than 12.5% above cost of service. I also recommend reducing the High Voltage (138 kV) revenue allocation by [redacted] to move this customer class to its cost of service, and fine-tuning the revenue allocation to Large Power Service ("LPS") to bring this class to its cost of service as well. The sum of these net reductions would be offset with a corresponding increase in the revenue allocation to the Residential class, which would also move this class closer to its cost of service, although a considerable subsidy would still remain in residential rates.

At AECC's proposed revenue requirement, I have apportioned my recommended revenue allocation as shown in Table KCH-5, which includes a buy-through reserve fund of $7,550,207 as explained below in my testimony. *For an alternate revenue requirement that may be approved by the Commission*, I recommend scaling down (or up as appropriate) each class's revenue allocation by an equal percentage of non-fuel revenues relative to my recommended rate spread at AECC's recommended revenue requirement shown in Table KCH-5, while still providing for the buy-through reserve fund of $7,550,207. As is the case for Table KCH-5, the buy-through reserve would be funded from a portion of the revenue reduction (relative to TEP's filed case) that would otherwise apply to customers in the classes eligible for the buy-through program, discussed below, which under my proposal would be LGS, LPS, and High Voltage.

(4) I recommend adoption of a buy-through program that is as similar as reasonably possible to the AG-1 program currently in effect in the APS service territory, but with a different funding mechanism than the APS program. While I

believe it would be preferable to allow Arizona customers full access to the electric power marketplace to take advantage of the benefits of competition as intended by the Arizona Legislature, a buy-through program represents a compromise that provides customers the opportunity to engage in market transactions and potentially reduce their energy costs, consistent with state policy, but without implementing full direct access service. A successful buy-through program will enhance the economic development climate of the TEP service territory and of the state generally.

I recommend adopting some of the features of the buy-through program presented by TEP, but modifying other features to make the program open to a wider variety of customers, making it a more viable option. I recommend changes to program scale, eligibility, pricing, terms of return to standard generation service, and the mechanics of fixed generation cost recovery. I also recommend a clarification to the program term.

Specifically:

(a) I recommend increasing the proposed 30 MW cap on participation proposed by TEP to 60 MW, and broadening the range of eligible customers by allowing customers to participate with a minimum load size of 3,000 kW (peak demand) and allowing aggregation of smaller loads in the LGS class owned by the same corporate entity to achieve that 3,000 kW threshold. I recommend that the term of the program will continue at least until the start of the first rate-effective period (following a general rate case order) occurring no less than four years from the starting date of the buy-through program.

(b) The monthly management fee of $0.004/kWh for buy-through service proposed by TEP is unreasonable and should be reduced to $0.002/kWh, based on the management fee review conducted by APS regarding its AG-1 program.

(c) Under the TEP program, the Generation Capacity component of the demand charge would continue to apply to 100% of the customer's billed demand. While some assignment of cost for generation reserves may be appropriate, the TEP proposal is more comparable to a stranded cost charge. The stranded cost approach should be rejected unless the customers are being provided with an opportunity to transition permanently to market pricing. Absent such an option, the going-forward charges for generation-related services should be limited to a charge for reserve capacity applied to 15% of the customer's billing load, priced at the unbundled Generation Capacity rate components for the customer's rate schedule. This pricing approach ties the charge for reserve capacity to TEP's planning reserve margin and is comparable to APS's AG-1 charge for reserve capacity.

My recommended 15% reserve capacity percentage is based on TEP's planning reserve margin and is comparable to the AG-1 reserve capacity charge levied by APS.

In addition, I recommend that the first $7,550,207 of any revenue requirement reduction apportioned to the classes eligible for the buy-through program be used to absorb TEP's revenue deficiency ascribed to the loss of fixed generation revenues from buy-through customers. In this way, both TEP and the customer classes not eligible to participate in the buy-through program would be held harmless from adoption of the buy-through provision.

(d) If, prior to the end of the planned four-year term of the program, and absent Commission termination of the program, a buy-through customer seeks to return to standard generation service and does not provide one-year's notice, TEP proposes to charge the returning customer the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh until the Company is reasonably able to integrate the customer back into the Company's generation planning. While I agree that this general approach is reasonable, I believe the proposed $20 per MWh mark-up is excessive and should be eliminated or significantly reduced to no greater than $4 per MWh.

(5) TEP's depiction of the components that make up each class's allocated costs by function and classification is distorted. I correct this error in order to accurately design unbundled LGS, LPS, and High Voltage rates.

(6) TEP's unbundled rate design is flawed in that the Company is improperly attempting to recover fixed generation-related costs in the unbundled Delivery-related components of the LGS, LPS, and High Voltage tariffs, contrary to the fundamentals of proper unbundled rate design. For this reason I recommend that TEP's proposed relationship between Delivery charges and Generation Capacity charges in its unbundled tariff for the LGS, LPS, and High Voltage classes be rejected. Instead, I recommend that the unbundled rate design presented in Exhibit KCH-20 attached to my testimony should be adopted. This unbundled rate design was prepared using my proposed rate spread at TEP's overall revenue requirement. The rate components in Exhibit KCH-20 should be scaled back as discussed in my testimony to the extent that lower class revenue requirements are approved in this case.

(7) TEP should be required to eliminate its proposed Delivery energy charges for demand-billed classes.

(8) The applicability criteria for Mobile Home Park Electric Service – GS-11F, and its proposed replacement rate schedule, GS-M-F, should be amended to remove restrictions on service to new customers or new facilities, or restrictions limiting the mobile home park rate schedule to customers served historically on the mobile home park rate. The tariff restrictions that prevent existing mobile home parks from switching to the mobile home park rate schedule are unjust and unreasonable and should be removed from the TEP tariff. At a minimum, the applicability should be amended such that there is no restriction on migrating to this rate schedule for any existing master-metered mobile home park.

(9) TEP's proposed changes to the LFCR mechanism should be rejected. The LFCR mechanism adopted in the last general rate case was the product of difficult negotiations. I am not persuaded that an LFCR is needed in the first instance, and I particularly disagree with levying this charge on LGS customers, as a significant part of TEP's concern regarding these customers can be addressed through rate design. Therefore, not only do I disagree with TEP's proposed changes, but I also recommend that LGS customers be exempted from this charge going forward.

(10) TEP's proposal to use a single percentage adjustment for the PPFAC is reasonable as the adjustment would be proportionate to each customer class's fuel costs. I support adoption of this change. However, TEP's proposal to change to a monthly reset of the PPFAC creates rate uncertainty from month to month and is potentially problematic. Although I am disinclined to support this change

on a standalone basis, I would not oppose this approach if it were adopted as a package in tandem with the 70/30 PPFAC risk sharing mechanism that I am recommending in my revenue requirement testimony.

COST OF SERVICE

Q. What is the purpose of cost-of-service analysis?

A. Cost-of-service analysis is conducted to assist in determining appropriate rates for each customer class. It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- *Separating* the utility's costs in accordance with the various *functions* of its system (e.g., generation [or production], transmission, distribution);
- *Classifying* the utility's costs with respect to the manner in which they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and
- *Allocating* responsibility for the utility's costs to the various customer classes based on principles of cost causation.

Q. What is the role of cost-of-service analysis in setting rates?

A. Each of the three steps above has an important role in the ratemaking process. Cost functionalization guides classification and allocation method selection based on the utility function served. If rates are unbundled by function, as they are required to be in Arizona, then separating the utility's costs by function also determines the generation-related, transmission-related, and distribution-related components of unbundled rates.

The classification of costs informs the selection of allocation methods, i.e., demand, energy, or customer-based. The classification of costs is also critical to the rate design process, i.e., in determining the proper customer charge, demand charge, and energy charge for each rate schedule.

Finally, the allocation of costs to customer classes guides the revenue allocation across customer classes, commonly referred to as "rate spread." In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

Q. Does TEP allocate generation plant costs between its retail customers and FERC-jurisdictional customers?

A. Yes.

Q. What approach has TEP used for allocating generation plant costs between TEP retail customers and FERC-jurisdictional customers?

A. TEP uses the four coincident peaks ("4CP") method for allocating generation plant costs between its state and federal jurisdictional loads. The 4CP method allocates fixed production costs based on the average of system peak demands in the four summer months, which is when TEP's production capacity requirements are determined.

Q. In your opinion, is the 4CP method appropriate for allocating TEP's jurisdictional generation plant costs?

A. Yes, it is. TEP's maximum system demands are driven by summer usage. Given the characteristics of TEP's system, the 4CP method properly aligns the allocation of the Company's fixed costs with cost causation.

Q. Please describe TEP's approach to class cost-of-service analysis.

A. As explained in the Direct Testimony of Craig A. Jones, the Company utilizes an embedded cost-of-service study to guide class revenue allocation and rate design. The Company has also conducted a marginal customer cost study, based on forward-looking costs, to guide its rate design for Residential and Small General Service customers.[2] TEP also utilizes the minimum-size method to classify certain distribution costs into customer-related and demand-related components.[3]

Q. What method does TEP use to allocate demand-related production and transmission costs to classes in the embedded cost study?

A. TEP uses the 4CP Average and Excess Demand ("4CP AED") method[4], utilizing the retail system 4CP load factor.

Q. What is your general assessment of TEP's approach to allocating demand-related production and transmission costs among rate classes?

A. As a general proposition, I support TEP's use of the 4CP AED method to allocate production demand and transmission costs to classes. However, I disagree with two details related to the Company's application of the 4CP AED method. Accordingly, I recommend two changes to TEP's calculation of the 4CP AED allocator, which I describe below.

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[2] Direct Testimony of Craig A. Jones, pp. 3-4, 10-11.
[3] *Id.*, p. 19-20.
[4] *Id.*, p. 25, ln. 27 – p. 26, lns. 1-5.

Q. Before turning to your recommended changes, please explain why you support TEP's use of the 4CP AED method to allocate production demand costs.

A. The 4CP AED method recognizes both class energy usage (average demand) and class demand at the time of system peak (through the 4CP) in allocating costs to customer classes. In the case of TEP, the 4CP corresponds to the Company's retail system peak demands in each of the four summer months, when system demand is at its greatest levels. As such, the method accurately captures the requirements that each class makes on the need for investment in generating facilities, and thus reasonably reflects each class's share of costs.

Specifically, the 4CP AED method uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor.[5] This portion of the cost is weighted by the system load factor. The cost of capacity above average demand is then allocated in proportion to each class's excess demand, where excess demand is measured as the *difference* between each class's 4CP demand and its average demand. This portion of the cost is weighted by 1 minus the system load factor. In this manner, the incremental amount of production plant that is required to meet loads that are above average demand is assigned to the users who create the need for the additional capacity.

The AED method is described in the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC Manual") in its section entitled "Energy Weighting

[5] This concept is discussed in the NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

Methods." This method has the virtue of meeting the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy.[6] As stated in the NARUC Manual, this method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor."[7] At the same time, the incremental amount of production plant that is required to meet loads that are above average demand is properly assigned to the users who create the need for the additional capacity.

The 4CP AED Method is used by APS and UNS Electric, Inc., and is also used by other electric utilities in the neighboring states of New Mexico, Colorado, and Texas.

Q. Do you also support TEP's use of the 4CP AED method for allocating transmission costs?

A. Yes. The reasons for using this method to allocate fixed production costs also extend to using it for allocating transmission costs.

Q. Please discuss your first recommended change to TEP's calculation of the 4CP AED allocation factors.

A. As I explained above, in the 4CP AED method, system load factor is utilized to determine the proportion of plant cost that is allocated on the basis of average demand (or energy). Load factor is normally calculated by dividing the energy used during a time period by the product of the peak demand during the

[6] Docket Nos. E-01345A-05-0816, et al. Decision No. 69663, pp. 70-71, 154.
[7] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

time period multiplied by the number of hours in the same time period. It thus provides a measure of an entity's actual energy usage relative to its theoretical maximum, given the peak demand of the measured entity (which can be a customer, customer class, or utility system).

TEP does not follow this normal convention in calculating system load factor. Rather than using the retail system peak demand in the denominator of the load factor calculation, TEP averages the retail peak demands of the four coincident peak months. In my view, this approach does not accurately measure system load factor for the test year, and overstates the annual load factor above its true value. Instead, system load factor should be measured by reference to TEP's highest peak demand for that year. This treatment is consistent with the method for measuring system load factor presented in the discussion of the AED method in the NARUC Manual. This measurement is not only the correct measurement of load factor, it is also the most appropriate measurement from a conceptual standpoint given the task at hand.

Q. Please explain this latter point.

A. Recall that the purpose of using system load factor in the 4CP AED method is to identify the proportion of costs to be allocated on the basis of average demand, which in turn is capturing the portion of plant that each class would require if its respective kilowatt-hour usage was consumed at a 100% load factor for the entire year. Consistent with this premise, the calculation of average demand in this exercise is a single annual value. This point is critical to the logic here because excess demand, which is measured using 4CP, only exists as a concept in relation to annual average demand (i.e., it is the excess above average demand). Thus, the load factor weight that is attached to this annual average demand should be measured using the single peak demand (1CP) for the test year. The number of CPs used in calculating excess demand – be it 1, 4, or some other number – is irrelevant to the determination of annual average demand and irrelevant to the determination of system load factor for the test period. There is but one system load factor during the year, not multiple load factors depending on how many CPs are used to calculate excess demand.

In addition to being conceptually correct from the standpoint of cost allocation, measuring load factor with respect to the highest peak demand is consistent with the approach TEP uses in assessing its load and resource balance as documented in the Company's integrated resource plan.[8]

Q. Please discuss your second recommended change to TEP's calculation of the 4CP AED allocation factors.

A. TEP's original calculation of the 4CP AED allocator resulted in a 4CP AED factor for the Lighting class of 0%. This occurred because the Lighting class had no demand during TEP's four coincident peaks, so that class's 4CP demand was less than its average demand, i.e., negative excess demand. This situation often occurs for Lighting customer classes when utilities utilize the 4CP AED method, and it is typically remedied by adjusting the calculation so that the excess demand for each class is no less than zero. My class cost-of-service study calculates the Lighting class's 4CP AED factor using zero excess demand and the class's share of average demand (or energy).

Q. Has TEP addressed the issue regarding the Lighting class's 4CP AED factor?

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[8] See TEP 2014 IRP, pp. 28-29.

A. Yes, the Company attempted to address this issue in response to a Staff data request.[9] Apparently, at Staff's request, TEP produced a version of its class cost-of-service study, which I term "TEP's 2nd Revised Model,"[10] incorporating non-coincident peak ("NCP") data in the calculation of its AED allocator. TEP's NCP AED approach produces a Lighting AED factor of slightly greater than 0%. However, under TEP's NCP AED approach, the excess demand component for the Lighting class is still negative. TEP's 2nd Revised Model also suffers from a number of other analytical flaws.

Q. What other analytical flaws in TEP's 2nd Revised Model have you identified?

A. TEP's 2nd Revised Model improperly applies the NCP AED method. Firstly, TEP continues to utilize the 4CP load factor, rather than the single peak demand load factor, to weight the average demand (or energy) component of the AED allocator. Secondly, rather than using each class's single annual NCP in the calculation of the AED allocator, TEP averages the NCP demands that occurred during each of the four coincident peak months. TEP has not formally revised its direct filing or offered any testimony supporting the use of the NCP AED method. I support adoption of the 4CP AED method, incorporating my two corrections described above.

Q. Aside from TEP's method for production demand and transmission cost allocation, do you have any other concerns with the embedded cost-of-service study prepared by TEP?

[9] TEP's Response to Staff Data Request 20.11, provided in Exhibit KCH-22.
[10] TEP's 2nd Revised Model was produced subsequent to TEP's 1st Revised Model I discuss below.

A. Yes. There are a number of errors and analytical flaws in TEP's original cost-of-service study unrelated to production demand and transmission cost allocation. Two of these errors have been acknowledged by TEP in response to AECC data requests:[11]

(1) TEP inadvertently failed to allocate any Meters or Services costs to the Large General Service ("LGS") class.

(2) TEP allocated customer-related distribution costs based on NCP demand rather than number of customers.

TEP provided a revised class cost-of-service model to AECC ("TEP's 1st Revised Model") on May 6, 2016 that corrects these two errors but has not formally revised its direct filing.

In addition, there are three additional errors and/or analytical flaws that TEP has not acknowledged at this time, to the best of my knowledge. These are:

(3) TEP (seemingly inadvertently) allocates the entirety of Administrative & General ("A&G") expenses based on number of customers.

(4) Despite specifying in its tariff that Large Power Service – Time of Use ("LPS-TOU") customers are to provide their own transformers and are subject to primary service and metering, TEP allocates line transformer costs to the LPS class and provides no cost recognition for LPS primary service.

(5) TEP's study does not allocate any portion of Other Operating Revenues to the proposed High Voltage (138 kV) class.

Q. Please explain the second error acknowledged by TEP, regarding the allocation of customer-related distribution costs.

[11] TEP's Responses to AECC Data Requests 3.3 and 3.4, provided in Exhibit KCH-22.

A. Certain distribution costs have a significant customer-related component, since distribution facilities are installed to deliver service to customer premises. As such, a considerable portion of the investment required to provide these facilities is directly related to the number of customers and their geographic dispersion on the utility's system. A well-designed and fair distribution cost-of-service study should take these aspects of cost causation into account.

The minimum-size method classifies a portion of certain distribution plant accounts as customer-related based on the minimum size distribution system required to serve each customer. The difference between the total plant investment and the customer-related portion is classified as demand-related. [12]

TEP uses the minimum-size method to determine the customer-related and demand-related portions of certain distribution plant accounts: FERC Accounts 364 (Poles, Towers & Fixtures), 365 (Overhead Conductors & Devices), 366 (Underground Conduit), 367 (Underground Conductors & Devices), and 368 (Line Transformers).[13] However, TEP's original class cost-of-service study allocates the entirety of these accounts to classes based on NCP demand.

TEP's 1st Revised Model properly allocates the customer-related portions of FERC Accounts 364 through 368, and proportionate amounts of related accumulated depreciation, O&M expenses and depreciation expense, based on customer counts. The remaining demand-related portion is allocated based on distribution NCP.

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[12] The NARUC Manual describes the minimum-size method on pp. 90-92.
[13] See TEP's Response to AECC Data Request 7.1, attachment AECC 7.1 TEP Min System Study v3 10-21-2015 without HW. The attachment Summary tab is provided in Exhibit KCH-22. TEP classifies FERC Accounts 369 (Services) and 370 (Meters) as 100% customer-related and allocates these costs using a meter cost-weighted customer allocator.

Q. Please explain the third analytical flaw listed above, regarding to the allocation of A&G expenses.

A. Apparently, TEP's study functionalizes A&G expenses based on wages, and classifies A&G expenses into demand-related and customer-related portions based on the various utility functions. However, TEP allocates the entirety of A&G expenses based on number of customers. This has the effect of over-allocating A&G expenses to classes with a relatively high number of customers – the Residential and Lighting classes.

Q. Have you attempted to correct the allocation of A&G expenses?

A. Yes. My class cost-of-service study allocates A&G expenses based on each class's allocated share of O&M expenses excluding A&G, corresponding to TEP's functional separation of A&G expenses. My correction reduces the allocation of A&G expenses to the Residential and Lighting classes.

Q. Please explain the fourth analytical flaw listed above, regarding the allocation of line transformer costs to the LPS-TOU class.

A. TEP's proposed LPS-TOU tariff states, "The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers." This language is consistent with the current LLP-14 and LLP-90 tariffs, which, with the exception of one customer served at 138 kV voltage, are being consolidated into the LPS-TOU tariff. However, TEP allocates line transformer costs to the LPS-TOU class like all other distribution classes, and provides no cost recognition or specific rate discount to LPS-TOU customers to reflect service at primary rather than secondary voltage.

In discovery, TEP contends that, "some level of transformation is appropriately included in the rates for this class," because customers served a variety of voltages were "grandfathered" onto the current LLP tariffs before the referenced language was added to the tariffs.[14]

TEP's class cost-of-service study does not recognize different loss factors for the LPS-TOU class, and does not separately identify and allocate the cost of its secondary distribution system. Ironically, the GS and LGS tariffs include a discount for customers served at primary voltage. However, no such discount is provided for LPS-TOU customers served at primary voltage.

In discovery, TEP indicates that 12 out of 18 LPS customers are served with customer-owned transformers, and 2 of those 12 are served with both customer-owned and TEP-owned transformers.[15] TEP indicates that 9 LPS customers are served at primary voltage, and 8 are served at secondary voltage, while 1 LPS customer is served at both primary and secondary voltage.[16]

Q. Have you corrected this analytical flaw?

A. In part. My class cost-of-service study begins to address this conceptual flaw by excluding the LPS-TOU class from line transformer cost allocation. Since the majority of LPS-TOU customers own their own transformers, and the tariff is designed as such, it would be appropriate to include a small "up-charge" for LPS customers who are instead served by TEP's transformers.

[14] TEP's Responses to AECC Data Request 3.1, provided in Exhibit KCH-22.
[15] TEP's Response to AECC Data Request 15.4, provided in Exhibit KCH-22.
[16] TEP's Response to AECC Data Request 15.2, provided in Exhibit KCH-22.

Regarding further differentiation between primary and secondary LPS customers, TEP claims it does not currently have the necessary billing determinants or load research data available.[17] TEP's line loss study did not develop a primary voltage loss factor.[18] I recommend that the Commission require TEP in its next rate case to separately identify the primary voltage LPS-TOU customer grouping and exclude such customers from secondary distribution cost allocation, as well as determine the primary voltage loss factor and reflect the factor in its cost-of-service analysis.

Q. Please explain the fifth analytical flaw listed above, regarding the allocation of Other Operating Revenues to the 138 kV class.

A. TEP allocates FERC Accounts 454 (Rent from Electric Property) and 456 (Other Electric Revenues) to customer classes based on rate base. Other Revenue serves to reduce the sales revenue that would otherwise be required for each rate class to achieve a uniform rate of return. However, TEP fails to allocate any Other Revenue to the proposed High Voltage (138kV) class in Schedule G-2 (Class Cost of Service Study - Summary at Proposed Rates). This error occurs because TEP ties the Other Revenue presented in Schedule G-2 to the Other Revenue presented in Schedule G-1 (Class Cost of Service Study - Summary at Present Rates). TEP does not depict the High Voltage customer as a distinct class in Schedule G-1, and instead includes the High Voltage customer within the LPS class. Thus, the entirety of Other Revenue allocated to the combined LPS class is

[17] TEP's Response to AECC Data Request 8.4, provided in Exhibit KCH-22.
[18] TEP's Response to AECC Data Request 3.2, provided in Exhibit KCH-22.

credited to the non-High Voltage LPS class in Schedule G-2, and no Other Revenue is allocated to the High Voltage class.

Q. Have you corrected this error?

A. Yes. My class cost-of-service study distributes the Other Revenue TEP allocates to the combined LPS class between the non-High Voltage LPS class and the High Voltage class based on rate base.

Q. What revenue requirement change would each class receive at TEP's requested revenue requirement if rates for each class were set at cost-of-service using your corrections to TEP's cost-of-service study?

A. The revenue requirement change for each class at TEP's requested revenue requirement is presented in Tables KCH-1 and KCH-2, below. Table KCH-1 shows the sales revenue change using the PPFAC of \$0.00682/kWh that was in effect at the time TEP filed its case, whereas Table KCH-2 shows the sales revenue change using TEP's *current* PPFAC of \$0.001501/kWh. I am presenting the revenue changes both ways to allow for comparability to TEP's filed case, while at the same time representing class impacts that would result from setting rates at cost-of-service as accurately as possible. TEP uses the PPFAC of \$0.00682/kWh to present the rate impacts from its proposed rate spread in Exhibit CAJ-2. By using the same PPFAC as TEP in Table KCH-1, the current revenues included my Table KCH-2 are comparable to the analysis shown by TEP in Exhibit CAJ-2. But at the same time, it is also important to present this information using the *current* PPFAC, which I do in Table KCH-2, because that depiction more accurately portrays rate impacts relative to current rates.

Table KCH-1
Revenue Change to Achieve Equalized Rate of Return
Using $0.00682/kWh PPFAC

Customer Class (a)	Current Adjusted Test Year Sales Revenue (b)	Sales Revenue at COS (c)	Sales Revenue Change to Achieve COS $ (d)	Sales Revenue Change to Achieve COS % (e)
Residential	421,989,186	538,426,766	116,437,580	27.6%
General Service	231,608,546	220,346,228	(11,262,319)	-4.9%
Large General Service	152,925,605	125,760,767	(27,164,838)	-17.8%
Large Power Service	[redacted]			
High Voltage 138kV	[redacted]			
Total LPS (TOU & 138kV)	146,480,335	127,244,153	(19,236,182)	-13.1%
Lighting	4,845,334	7,080,876	2,235,542	46.1%
Total Sales Revenue	957,849,006	1,018,858,790	61,009,784	6.4%

Table KCH-2
Revenue Change to Achieve Equalized Rate of Return
Using Current PPFAC

Customer Class (a)	Current Adjusted Test Year Sales Revenue (b)	Sales Revenue at COS (c)	Sales Revenue Change to Achieve COS $ (d)	Sales Revenue Change to Achieve COS % (e)
Residential	402,568,874	538,426,766	135,857,892	33.7%
General Service	221,889,211	220,346,228	(1,542,984)	-0.7%
Large General Service	145,189,541	125,760,767	(19,428,773)	-13.4%
Large Power Service	[redacted]			
High Voltage 138kV	[redacted]			
Total LPS (TOU & 138kV)	135,770,825	127,244,153	(8,526,672)	-6.3%
Lighting	4,638,212	7,080,876	2,442,664	52.7%
Total	910,056,663	1,018,858,790	108,802,127	12.0%

Q. What observations do you draw from Tables KCH-1 and KCH-2?

A. The Residential and Lighting classes require significant increases to achieve equalized rates of return under TEP's proposed revenue requirement. In contrast, the LGS, High Voltage, LPS, and GS classes require rate decreases to achieve equalized rates of return.

Q. In preparing Table KCH-1 and KCH-2 did you have to make any adjustments to TEP's data?

A. Yes. TEP is proposing to reconfigure its customer classes to a considerable extent. For example, TEP is proposing to create a new Medium General Service rate schedule and a new High Voltage rate schedule, as well as requiring certain customers to migrate between existing classes. However, in presenting its class revenue changes, TEP does not update current revenues to reflect the new composition of the classes. That is, in Schedule H-1, for example, the *proposed* revenues reflect the *new* class composition, while the *current* revenues reflect the *old* (current) class composition, which makes the *change* in revenues presented in Schedule H-1 almost meaningless for several classes. Consequently, the only way to gain insight into class impacts in TEP's filing is to review the rate impact tables presented in Exhibit CAJ-2, but even these entries do not provide a comprehensive depiction of what is occurring at the class level.

In order to avoid this pitfall I have adjusted current revenues in Tables KCH-1 and KCH-2 to reflect TEP's proposed composition of each class. By presenting the information in this way, I hope to make the class impacts shown in the tables more understandable.

REVENUE ALLOCATION

Q. What general guidelines should be employed in spreading any change in rates?

A. In determining revenue allocation, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

Q. How does the spread of rates proposed by TEP relate to class recovery of cost of service?

The revenue allocation proposed by TEP is presented in Table KCH-3, below, alongside current revenues calculated using the current PPFAC rate. The difference between TEP's proposed revenue allocation and cost allocation using my corrected class cost-of-service study represents the subsidy received or paid by the class at TEP's proposed rate spread.

Table KCH-3
TEP's Proposed Revenue Spread
& Resulting Subsidies

Customer Class (a)	Current Adjusted Test Year Sales Revenue (b)	TEP Proposed $ Change (c)	TEP Proposed % Change (d)	Subsidy Paid/ (Received) at TEP Spread[19] (e)	Subsidy Paid/ (Received) at TEP Spread % of COS[20] (f)
Residential	402,568,874	67,399,985	16.7%	(68,457,908)	-12.7%
General Service	221,889,211	35,290,387	15.9%	36,833,371	16.7%
Large General Service	145,189,541	12,020,623	8.3%	31,449,396	25.0%
Large Power Service	[redacted]				
High Voltage 138kV					
Total LPS (TOU & 138kV)	135,770,825	(7,171,556)	-5.3%	1,355,116	1.1%
Lighting	4,638,212	1,262,689	27.2%	(1,179,975)	-16.7%
Total	910,056,663	108,802,127	12.0%	-	0.0%

As shown in Table KCH-3, the LPS class grouping (LPS-TOU and High Voltage 138kV) is relatively close to cost of service under TEP's proposed rate spread. However, the Residential class receives a large subsidy that is primarily funded by LGS and GS classes and to a lesser extent, the High Voltage class. Indeed, TEP's proposed LGS rates are 25.0% above cost of service and GS rates are 16.7% above cost of service.

Q. Using TEP's requested revenue requirement as a benchmark for comparison purposes, do you recommend any changes to TEP's proposed revenue allocation?

A. Yes. TEP's proposed revenue allocation for the LPS class is reasonably close to its cost of service, but I believe the subsidy being paid by GS, LGS, and High Voltage customers is too great. Therefore, I recommend reducing the GS and LGS revenue allocation such that the rates for each class are no more than

[19] Column (e) equals Column (b) plus Column (c) minus Table KCH-2 Column (c).
[20] Column (f) equals Column (e) divided by Table KCH-2 Column (c).

12.5% above cost of service. I also recommend reducing the High Voltage revenue allocation by [redacted] to move this customer class to its cost of service, and fine-tuning the revenue allocation to LPS to bring this class to its cost of service as well. The sum of these net reductions would be offset with a corresponding increase in the revenue allocation to the Residential class, which would also move this class closer to its cost of service, although a considerable subsidy would still remain in residential rates. My proposed revenue allocation is presented in Table KCH-4, below.

Table KCH-4
AECC/Noble Solutions Proposed Revenue Spread
At TEP's Proposed Revenue Requirement

Customer Class (a)	Current Adjusted Test Year Sales Revenue (b)	AECC/ Noble Solutions Proposed $ Change (c)	AECC/ Noble Solutions Proposed % Change (d)	Subsidy Paid/ (Received) at AECC Spread[21] (e)	Subsidy Paid/ (Received) at AECC Spread % of COS[22] (f)
Residential	402,568,874	93,774,493	23.3%	(42,083,399)	-7.8%
General Service	221,889,211	26,000,295	11.7%	27,543,278	12.5%
Large General Service	145,189,541	(3,708,677)	-2.6%	15,720,096	12.5%
Large Power Service	[redacted]				
High Voltage 138kV					
Total LPS (TOU & 138kV)	135,770,825	(8,526,672)	-6.3%	-	0.0%
Lighting	4,638,212	1,262,689	27.2%	(1,179,975)	-16.7%
Total	910,056,663	108,802,127	12.0%	-	0.0%

Q. Your revenue requirement recommendation would reduce TEP's requested revenue requirement by $48.587 million. What is your recommended rate spread at that lower revenue requirement?

A. My recommended rate spread at AECC's recommended revenue requirement is derived by scaling back each class's revenue allocation by an equal

[21] Column (e) equals Column (b) plus Column (c) minus Table KCH-2 Column (c).
[22] Column (f) equals Column (e) divided by Table KCH-2 Column (c).

percentage of non-fuel revenues relative to my recommended rate spread at TEP's requested revenue requirement. This revenue allocation is shown in Table KCH-5, below. My rate spread also shows a line entry for a "buy-through reserve" that would fund the generation fixed cost associated with the experimental buy-through program, as discussed in the next section of my testimony. This reserve would come from a portion of the revenue reduction that would otherwise apply to customers in the classes eligible for the buy-through program, which under my proposal would be LGS, LPS, and High Voltage. This reserve fund is shown in the line entry of (7,550,207) in the row entitled "Experimental Rider-14 reserve."

Table KCH-5
AECC/Noble Solutions Recommended Revenue Spread
At AECC's Proposed Revenue Requirement

Customer Class (a)	Current Adjusted Test Year Sales Revenue (b)	AECC/Noble Solutions Proposed $ Change (c)	AECC/Noble Solutions Proposed % Change (d)
Residential	402,568,874	68,531,433	17.0%
General Service	221,889,211	13,428,994	6.1%
Large General Service	145,189,541	(5,475,802)	-3.8%
Large Power Service	[redacted]		
High Voltage 138kV			
Total LPS (TOU & 138kV)	135,770,825	(9,689,345)	-7.1%
Lighting	4,638,212	948,578	20.5%
Sub-Total	910,056,663	67,743,858	7.4%
Experimental Rider-14 Reserve		(7,550,207)	
Total	910,056,663	60,193,651	6.6%

Q. Do you recommend using the same approach to rate spread and funding the buy-through program if the Commission were to adopt a revenue requirement reduction that is different than the amount of AECC's proposed recommended revenue requirement reduction?

A. Yes. For an alternate revenue requirement, I recommend scaling down (or up as appropriate) each class's revenue allocation by an equal percentage of non-fuel revenues relative to my recommended rate spread at AECC's recommended revenue requirement shown in Table KCH-5, while still providing for the buy-through reserve fund of $7,550,207. As is the case for Table KCH-5, the buy-through reserve would be funded from a portion of the revenue reduction (relative to TEP's filed case) that would otherwise apply to customers in the classes eligible for the buy-through program, which under my proposal would be LGS, LPS, and High Voltage.

Q. What do you recommend in the event that the Commission does not order a revenue requirement reduction relative to TEP's proposed revenue increase that is sufficient to fund the buy-through requirements?

A. In that event, although it appears unlikely, I recommend that the program costs be funded from the classes eligible for the buy-through program using the rate spread approach I am recommending at the approved revenue requirement.

BUY-THROUGH TARIFF

Q. Please provide an overview of the buy-through tariff presented by TEP in this proceeding.

A. TEP has submitted a buy-through tariff in this proceeding pursuant to the settlement agreement approved by the Commission in the proceeding concerning the acquisition of UNS Energy by Fortis, Inc.[23] However, TEP is opposed to the

[23] Docket Nos. E-04230A-14-0011 and E-01933A-14-0011, Settlement Agreement Attachment A, Condition 31, approved by the Commission in Decision No. 74689.

implementation of this tariff, contending it would allow certain large customers to "cherry pick" currently available capacity in the market.[24]

As described in Mr. Jones's Direct Testimony, Experimental Rider-14, Alternative Generation Service, is designed as an optional program to provide an alternative generation arrangement for LPS-TOU and High Voltage customers.

Q. How would this alternative generation arrangement operate?

A. According to Mr. Jones's Direct Testimony, the participating customer would select a wholesale generation service provider with whom to contract to sell power to the Company on the customer's behalf. The power would be delivered to the Company's point(s) of delivery, and the Company would provide transmission and delivery services under the customer's current retail rate schedule.[25]

The Company would purchase and manage this generation for the customer for a management fee of $0.0040 per kWh.[26] The Company would also serve as the scheduling coordinator and would provide Imbalance Service according to the Company's Open Access Transmission Tariff, with Imbalance Energy based on the generation service provider's portfolio of customer loads. Customers would be charged for Imbalance Service at a rate greater than $0.00 per kWh, and less than or equal to the rate charged to the generation service provider by TEP. The Company would then bill the customer for the generation

[24] Direct Testimony of Craig A. Jones, pp. 61-62.
[25] *Id.*, p. 62.
[26] *Id.*

service provider's charged amounts for Generation Service and Imbalance Service.[27]

The customer would also be subject to all of the charges and adjustments in its retail rate schedule with the exception of the Base Power Charge and the PPFAC. In addition, the customer would be responsible for the hedging cost associated with the customer's standard generation service at the time the customer takes service under the rider.[28]

Q. Please describe the buy-through program size, eligibility requirements, and program term as designed by TEP.

A. The total program would be limited to 30 MW of peak load, and would be available to customers in the LPS-TOU and High Voltage rate classes with peak demands of 3,000 kW or greater. Eligible customers could apply during the initial enrollment period, and if the total megawatts of peak load from the applications exceed the program maximum, customers would be selected through a lottery process to be developed by TEP.[29] The Company proposes that the program be available for no more than four years from the effective date of new rates in this docket.[30]

Q. What would happen if the generation service provider defaults, or the customer wants to return to standard generation service?

A. If the generation service provider cannot meet its contractual obligations, the customer must notify the Company and select another generation service provider within 60 days. The Company would supply power to the customer prior

[27] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet No. 714-2.
[28] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet Nos. 714-1 through 714-2.
[29] Direct Testimony of Craig A. Jones, p. 63.
[30] *Id.*, p. 62.

to execution of the new power contract at the Dow Jones Electricity Palo Verde Daily Index price plus $20 per MWh.

If the customer wishes to return to standard generation service without providing one year notice to the Company and prior to program termination, the Company would supply power to the customer at the Dow Jones Electricity Palo Verde Daily Index price plus $20 per MWh until the Company is able to integrate the customer back into its generation planning and provide power at standard retail rates.[31]

Q. What is your assessment of the buy-through program presented by TEP?

A. Arizona Revised Statute §40-202(B) declares that "It is the public policy of this State that a competitive market shall exist in the sale of electric generation service."[32] Although the Commission adopted Retail Electric Competition Rules ("Rules") in the furtherance of this policy and commenced implementation, retail competition, also known as direct access service, has been suspended for more than a decade in Arizona. In the meantime, direct access service has been providing benefits to customers in many other states in the country.

Q. **Are you aware that several parties involved in TEP's Application for Approval of the Company's 2016 REST Implementation Plan[33], which has been consolidated with this rate proceeding, have opined on the applicability of A.R.S. §40-202(B) to the Commission, and the state of the Rules in general?**

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[31] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet No. 714-3.
[32] ARS 40-202(B).
[33] Docket No. 01933A-15-0239.

A. Yes. I understand that the Commission consolidated that application with this rate proceeding for the very specific purpose of determining whether approval of TEP's proposed self-owned residential solar ("TORS") program and Residential Community Solar ("RCS") program is in the public interest, given the rate impacts to customers. I believe it would be inadvisable for the Commission to make any legal determination concerning the applicability of A.R.S. §40-202(B), or the state of the Rules, as a result of the evidentiary hearing intended to focus on the narrow issues surrounding the TORS and RCS programs. AECC will be filing a Reply Brief to address these legal issues.

Q. What is your assessment of the buy-through program presented by TEP?

A. TEP's opposition to the buy-through program is misplaced. Ironically, the Company argues that approval of its TORS and RCS programs is in the public interest because they give customers *more choice*, and a greater opportunity to save money. The same arguments can be made for commercial and industrial customers seeking to manage power costs through market transactions, but TEP has selectively declined to support allowing customers these types of choices.

While I believe it would be preferable to allow Arizona customers full access to the electric power marketplace to take advantage of the benefits of competition as intended by the Arizona Legislature, a buy-through program represents a compromise that provides commercial and industrial customers the opportunity to engage in market transactions and potentially reduce their energy costs, consistent with state policy, but without implementing full direct access service. Moreover, a successful buy-through program will enhance the economic development climate of the TEP service territory and of the state generally.

Given that direct access service is not currently available in Arizona, I recommend adoption of a buy-through program in the TEP service territory as a "second best" option. I recommend adoption of a program that is as similar as reasonably possible to the AG-1 program currently in effect in the APS service territory, but with a different funding mechanism than the APS program. This means adopting some of the features of the buy-through program presented by TEP, but modifying other features to make the program open to a wider variety of customers, thus making it a more viable option. Specifically, I recommend changes to program scale, eligibility, pricing, terms of return to standard generation service, and the mechanics of fixed generation cost recovery. I also recommend a clarification to the program term.

Q. What is your recommended clarification to the program term?

A. I do not disagree with TEP's proposal to target a four-year period for the term of the program. However, I believe it is important for consideration of program extension or modifications to be considered in the context of a future general rate case prior to the termination of the program. Therefore, I recommend that the term of the program be restated to indicate that the buy-through program will continue at least until the start of the first rate-effective period (following a general rate case) occurring no less than four years from the starting date of the buy-through program.

Q. Please describe the change to program scale that you are recommending.

A. I believe that the program cap of 30 MW proposed by TEP is too low. TEP has approximately 30% of the non-residential load that APS has. APS's AG-

1 program is capped at 200 MW. A comparable cap for TEP is around 60 MW, which is what I am recommending.

Q. Please describe the changes to program eligibility that you are recommending.

A. I recommend broadening the range of the customers that would be eligible to participate in the buy-through program. Specifically, I recommend allowing customers to participate with a minimum load size of 3 MW (peak demand), as proposed by TEP, but allowing aggregation of smaller loads in the LGS class owned by the same corporate entity to achieve that 3 MW threshold. Each single site aggregated to reach the 3 MW threshold should have experienced a billing demand of at least 200 kW in the past year to be eligible.

Q. Why do you recommend broadening the range of eligible customers?

A. The APS buy-through program reserved 50% of the initial capacity for customers on Schedule 32-L, which roughly corresponds to the TEP LGS class. The APS program allows Schedule 32-L (and in some cases smaller) customers to aggregate their single site loads to achieve the 10 MW minimum size required to participate in the AG-1 program. Experience with the AG-1 program demonstrates that there is keen interest on the part of commercial and public sector customers to participate in the market for electric power. This opportunity should be available to similarly-situated TEP customers.

Q. You state that the APS AG-1 program allows aggregation but requires a 10 MW minimum aggregated load size. Why are you recommending a 3 MW aggregated load size for TEP?

A. APS has a larger service territory than TEP, so there is greater potential to aggregate smaller loads up to a 10 MW threshold. Indeed, the APS non-residential retail load is about three times the size of TEP's. My recommended 3 MW threshold for aggregated loads in the TEP service territory simply scales back the APS aggregate threshold to take into account the smaller TEP service territory.

Q. Are there aspects of buy-through program pricing proposed by TEP that you agree are reasonable?

A. Yes. TEP's proposal to assign a pro rata share of previously-incurred hedging costs is reasonable in *concept.* I note, however, that the reasonableness of the specific calculations that TEP intends to apply has yet to be demonstrated.

Q. What changes to buy-through program pricing are you recommending?

A. I am recommending changes to the proposed monthly management fee as well as to the continuation of generation capacity charges proposed by TEP.

Q. What change to the monthly management fee are you recommending?

A. TEP is proposing a monthly management fee of $0.004/kWh for buy-through service. While I agree that some management fee is appropriate, I believe the fee proposed by TEP is excessive, as it is more than six times greater than the $0.0006/kWh management fee charged by APS for AG-1 service. In its review of its AG-1 program, APS concluded that a tripling of the management fee would be appropriate if the program is continued.[34] This would correspond to a management fee of $0.0018/kWh. Based on that conclusion, I believe a management fee of $0.002/kWh, or half of what TEP is proposing, is reasonable.

[34] See Docket No. E-01345A-16-0036, Direct Testimony of Leland R. Snook, p. 45.

Q. What changes to TEP's proposed generation charges for buy-through customers are you recommending?

A. Under the TEP program, the unbundled Generation Capacity rate components would continue to apply to 100% of the buy-through customer's billed demand. In other words, in addition to purchasing its generation service from a competitive supplier, the buy-through customer would be required to continue to pay TEP for the fixed cost of generation service that the buy-through customer would be utilizing. This requirement to "pay twice" for fixed generation service obviously undermines the economics of participating in the program; indeed, as TEP is opposed to adoption of the program, this feature appears designed to ensure that the program would fail, even if it was approved. This feature of TEP's proposal is unreasonable, does not have an analogue in the APS AG-1 program and should not be adopted.

Further, the fixed generation charges proposed by TEP are in effect stranded cost charges that are typically levied by utilities when direct access service is being offered. A critical distinction with respect to retail choice programs is that in exchange for the customer's payment of stranded cost charges for a period of time (e.g., five years), the customer is allowed to migrate *permanently* to market participation with no further stranded cost obligation. That is not the case with the proposed buy-through program. When the term of the customer's participation in the buy-through program has expired, the customer is presumed to have no continued right to market procurement unless the program is extended and the customer is able to regain a slot. In short, if the participating customer is required to pay a stranded cost charge as proposed by TEP, then a more permanent shopping option, accompanied by a timetable for cessation of stranded cost obligations, should be available. Moreover, stranded cost recovery for TEP was previously implemented and completed by the terms of the amended Settlement Agreement approved by the Commission in Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.

Rather than the stranded cost charge proposed by TEP, the going-forward charges for generation-related services should be limited to a charge for reserve capacity applied to 15% of the customer's billing load at the unbundled Generation Capacity rate components for the customer's rate schedule.[35] This pricing approach ties the charge for reserve capacity to TEP's planning reserve margin in the Company's Integrated Resource Plan ("IRP") and is comparable to APS's AG-1 charge for reserve capacity.

Q. What does planning reserve margin refer to and how is it relevant?

A. A planning reserve margin is used in the resource planning process to compensate for uncertainty surrounding future load forecast changes and resource contingencies such as generation or transmission forced outages. The planning reserve margin is calculated as the amount of firm peak resource capacity in excess of projected retail demand as a percentage of total demand. The planning reserve margin used by TEP in the Company's IRP is 15%.[36]

By way of comparison, under the AG-1 tariff, the monthly reserve capacity charge is applied to 15% of the customer's billed demand priced at

[35] As described in the following section my testimony, I recommend that the LPS and 138 kV Delivery energy charges be re-designated as Generation Capacity energy charges. For LPS and 138 kV buy-through customers, I recommend that the reserve capacity charge be applicable to 15% of kWh at the Generation Capacity energy rate and 15% of billing kW at the unbundled Generation Capacity demand charge component.

[36] See TEP 2014 IRP, p. 43 and 2016 Preliminary IRP, p. 33.

APS's cost-based rate for generation capacity filed at FERC, consistent with APS's planning reserve margin of 15%.[37]

Q. If the pricing features proposed by TEP are not adopted, how should the Company's revenue deficiency associated with the buy-through program be recovered?

A. In my discussion of rate spread, above, I recommended that the first $7,550,207 of any revenue requirement reduction apportioned to LGS, LPS, and High Voltage customers be used to support the Experimental Rider-14 buy-through program.

This funding mechanism would work as follows. The first $7,550,207 of revenue requirement reduction apportioned to LGS, LPS, and High Voltage (collectively) would <u>not</u> be applied to a change in rates per se. Rather, this $7,550,207 would be used to absorb TEP's revenue deficiency that is attributed to the reduction in fixed generation revenues from buy-through customers. In this way, TEP is able to recover its approved revenue requirement, and the customer classes not eligible to participate in the program are held harmless from adoption of the buy-through provision.

Q. Why is it reasonable to recover the fixed generation costs from the classes eligible to participate in the program rather than directly assigning the cost recovery to the buy-through participants?

A. As I discussed previously, directly assigning stranded cost charges might be appropriate if participants were being offered a more permanent shopping option. Further, the opportunity to participate in the program provides a potential

[37] See APS 2014 IRP, p. 93.

value-added option for the members of the eligible classes. It strikes me as more reasonable to recover the fixed generation costs of the buy-through program through a foregone rate reduction from the eligible classes rather than levying a 100% stranded cost charge as proposed by TEP.

Q. How did you calculate that the revenue required to fund the buy-through program is approximately $7,550,207 per year?

A. I applied the unbundled Generation Capacity rate components, corrected as discussed in the next section of my testimony, to the load associated with my recommended 60 MW program cap for each of the eligible classes (LGS, LPS, and High Voltage), assuming fully-subscribed participation.[38] I then reduced the resulting amounts by the revenues from the 15% reserve capacity charge I am recommending. The $7,550,207 estimate is the simple average of this calculation applied to the LGS, LPS, and High Voltage rate schedules.[39]

To the extent that program initiation is delayed and does not coincide with the start of the rate-effective period in this case, then there should be a downward adjustment to the annual imputed cost of the program prorated over the planned four-year term of the program, to account for the over-recovery of revenues from eligible classes during the delayed start-up.

Q. What do you recommend if the buy-through program is not fully subscribed?

[38] To calculate revenue associated with my recommended LPS and 138 kV Generation Capacity energy charges, described in the following section, I estimated the kWh associated with 60 MW of load for LPS and 138 kV.

[39] If all buy-through participants are in the LGS class, the cost would be $8,109,000 per year. Similarly, if all buy-through participants are in LPS class the cost would be $7,006,300 per year and if all buy-through participants are in the High Voltage class the cost would be $7,535,320 per year. My estimate of $7,550,207 is the simple average of this range.

A. If the buy-through program is not fully subscribed, then the revenues set aside to fund the program that turn out to be superfluous should be deferred and returned to the eligible classes through a suitable rate mechanism, perhaps through the PPFAC.

Q. Please explain your proposed change to the Return to Company's Standard Generation Service provision of Experimental Rider-14.

A. If, prior to the end of the planned four-year term of the program, and absent Commission termination of the program, a buy-through customer seeks to return to standard generation service and does not provide one-year's notice, TEP proposes to charge the returning customer the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh until the Company is reasonably able to integrate the customer back into the Company's generation planning. While I agree that this general approach is reasonable, I believe the proposed $20 per MWh mark-up is excessive. By comparison, APS's AG-1 program also requires that an "early" returning buy-through customer pay market rates for up to one year, but without an additional mark-up. I believe the $20 per MWh mark-up proposed by TEP should be eliminated or significantly reduced to no greater than $4 per MWh, to provide some margin to TEP for facilitating this pass-through of market costs.

Q. Are you aware of whether any AG-1 customers have sought to return to APS standard generation service prior to the planned term of the AG-1 program?

A. To the best of my knowledge, no AG-1 customers have sought to return to APS standard generation service prior to the planned term of the AG-1 program.

Q. Do you have any additional comments regarding the role of a buy-through program in the TEP service territory?

A. Yes. TEP steadfastly opposes adoption of a buy-through program yet continues to add generation resources that increase costs for all customers. This rate proceeding includes requested revenue requirement increases for the Gila River plant, Springerville Unit 1, and TEP-owned solar plants. Further, the Company indicates that even with the planned acquisitions of both the 75% interest in Gila River Unit 3 and the 49.5% interest in Springerville Unit 1, as well as the build out of utility scale solar generation resources, the Company was still short 200 MW in peaking capacity in 2015, growing to a deficit of 570 MW in 2018 with the retirement of San Juan Unit 2, according to TEP's 2014 IRP.[40]

In light of these resource needs, rather than opposing the buy-through program, it would make far more sense for TEP to take advantage of customers' interest in acquiring power from the marketplace and use a buy-through program as a planning tool for avoiding the acquisition of generation resources that may be unnecessary if customer purchases of market power were allowed to proceed under a buy-through program.

Finally, TEP has indicated that the Company plans to revise its billing determinants in its rebuttal filing to take account of planned reductions in operations for a major customer. I will respond to that revision in my surrebuttal testimony. I will note at this time that to the extent future loads for this customer are uncertain, it may be useful to consider market options such as buy-through for

[40] See TEP Response to AECC Data Request 16.3.c.

meeting the future service needs of this customer, perhaps even outside the 60 MW cap I am proposing for the buy-through program generally.

Q. Are you aware that APS has proposed to eliminate the AG-1 program in its recent general rate case filing?

A. Yes, I am.

Q. Does APS's proposal to eliminate the AG-1 program impact your recommendations regarding the adoption of a buy-through program in the TEP service territory?

A. No, not at all. I have incorporated APS's observations regarding the AG-1 management fee into my recommendations for TEP. Further, I note that APS's analysis regarding many of the program details indicates that many aspects of the program worked reasonably well.[41] Aspects of the program that may require improvement, such as retail imbalance service, can be addressed as part of discussions among stakeholders in implementing a TEP buy-through program. But most fundamentally, the opposition of utility management and shareholders to allowing Arizona customers to benefit from market pricing is unsurprising and should be given little weight when compared to the declared policy of the State. A buy-through program provides a modest "second best" vehicle to allow customers some of the benefits from competition in generation services, consistent with the State's declared policy.

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[41] APS indicates that program operations such as power scheduling, settlements, information exchanges and billing were generally successful, although improvements could be made to these operations, including more automation. Docket No. E-001345A-16-0036, Exhibit LRS-6DR, p. 2.

UNBUNDLED RATE DESIGN

Q. What aspects of TEP's proposed rate design are you addressing in your testimony?

A. My testimony addresses the rate design for TEP's *unbundled* demand charges for the LGS, LPS, and High Voltage classes. In addition, I address elimination of an energy charge for Delivery service in the rates of demand-billed classes. My absence of comment on other aspects of TEP's rate design should not be interpreted as support for (or opposition to) TEP's proposed rate design generally.

Q. By way of background, please explain the significance of an unbundled tariff.

A. An unbundled tariff is one in which utility rates are separated according to function, in particular, generation, transmission, and distribution (or delivery service). The Commission's rules carefully prescribe the requirements for filing an unbundled tariff.[42] The fundamental requirement in any well-designed unbundled tariff is that each unbundled component should only recover costs associated with its specific function. That is, the unbundled delivery service charge should only recover delivery-services-related costs (and not generation costs), the unbundled generation charge should only recover generation-related costs, and the unbundled transmission charge should only recover transmission-related costs.

A well-designed unbundled tariff is essential to implement a buy-through program because customers in such a program purchase their generation service from third parties and thus the rates they pay the utility must accurately

[42] See AAC R14-2-1606.C.2.

distinguish the avoidable generation costs from the other components in the rate schedule.

As required by Commission rules, TEP's rate schedules show rates both on a bundled and unbundled basis.

Q. What is the appropriate basis for designing unbundled rates?

A. The unbundled rate design should be tied to the class costs by function calculated in the class cost-of-service study. Although class revenues may be above or below full cost of service, the unbundled rates should reflect the underlying functional costs to the nearest extent practicable.

Q. Do you agree with TEP's depiction of the functional components of each class's allocated costs?

A. No. In addition to the analytical flaws affecting class cost allocation discussed in the Cost of Service section of my testimony, TEP's depiction of the functional components that comprise each class's costs is distorted.[43] After costs are allocated to customer classes, TEP breaks these costs into various functions by FERC account for each class, based on the overall functional composition of the FERC account for the system. This is problematic because classes utilize the utility functions to different degrees. For example, the High Voltage class utilizes only a minimal amount of the distribution system related to metering. It is inappropriate to attribute a sizeable amount of the High Voltage intangible plant, general plant, or A&G expenses to the distribution function.

[43] TEP presents these results on the tabs named RES byFunction, GS byFunction, LGS byFunction, LPS byFunction, 138kV byFunction, and LIGHT byFunction in its class cost of service model. I also corrected the depiction of income taxes for the LPS and 138kV classes on their respective Function tabs.

The problem I am describing affects numerous FERC accounts that serve multiple functions and/or are comprised of both demand-related and customer-related costs. These calculations affect the functional unit costs by class, which are the appropriate basis for designing unbundled rates. My cost-of-service study corrects the depiction of each class's functionalized and classified cost components.

Q. Do you have concerns with the rate design of TEP's unbundled tariff?

A. Yes. TEP's unbundled rate design is flawed in that the Company is attempting to recover fixed generation-related costs in the Delivery-related components of the LGS, LPS, and 138 kV rates, contrary to the fundamentals of proper unbundled rate design. For example, TEP's original class cost-of-service study, upon which TEP's filed unbundled rates are based, calculated a per-unit demand production cost of $10.60 per kW for the LGS class. However, TEP's proposed LGS tariff states an unbundled Generation Capacity demand charge component of only $7.95 per kW. Conversely, the unbundled Delivery demand charge component is set above cost. According to TEP's original cost of-service-study, the per-unit distribution demand cost for the LGS class is $3.13 per kW, but TEP proposes an unbundled LGS Delivery demand charge component of $3.86 per kW, in addition to substantial Delivery energy charges for the class.

Q. Why is this a problem?

A. It is a problem because the fundamental economic proposition in a buy-through rate is that the buy-through customer is able to bypass either all, or a significant portion of, the unbundled generation charges. If the utility's unbundled rate design shifts cost recovery from generation charges to distribution (or delivery) charges, then the avoidable generation costs will be underpriced and unavoidable distribution charges will be overpriced. As a result, the ability of customers to shop for buy-through power will be thwarted. Indeed, that is exactly what is likely to occur if TEP's unbundled rate design is accepted.

This situation could significantly undermine the economics of acquiring generation service in the power market. Indeed, shifting generation-related costs into the distribution (or delivery) charge is contrary to the very purpose of unbundling rates. It also appears to be contrary to the requirements of the Rules (AAC R14-2-1606.H.2), which states that rates for unbundled services "shall reflect the costs of providing the services."

Q. Have you calculated alternative unbundled rates for the LGS, LPS, and High Voltage classes?

A. Yes. I have calculated a set of alternative unbundled rates, based on the results of my corrected cost-of-service study and recommended revenue allocation at TEP's proposed revenue requirement. My proposed rate design is presented in Exhibit KCH-20.

Q. As part of your review of the unbundled tariff components, do you have any additional rate design recommendations?

A. Yes. A portion of the Delivery Charges for demand-billed customers is stated as an energy charge. This is not good rate design. The cost of delivery service is exclusively a function of customer-related costs and demand-related costs; consequently, recovery of these costs should occur exclusively through fixed customer charges and demand charges, not energy charges. Consequently, TEP should be required to eliminate its proposed Delivery energy charges for demand-billed classes. My proposed rate design eliminates the Delivery energy charges, while the overall recovery through the unbundled Delivery demand charge component and the Basic Service Charge is proportionate to the underlying Distribution costs.

To avoid too great a change in the overall relationship between total demand and total energy charges in TEP's rate design for the LPS and High Voltage classes, I have retained an energy charge at the same rate proposed by TEP for Delivery service and applied this charge to the recovery of Generation Capacity costs, which reduces the unbundled Generation Capacity demand charge from the rate it would be otherwise.

Q. What is your recommendation to the Commission on this issue?

A. TEP's proposed relationship between delivery demand charges and generation capacity demand charges in its unbundled tariff should be rejected. Instead, I recommend that the unbundled rate design presented in Exhibit KCH-20 should be adopted at TEP's proposed revenue requirement. To the extent that the revenue requirement for the LGS, LPS, and/or High Voltage classes is reduced from the levels assumed in Exhibit KCH-20, then the unbundled delivery charges and generation charges (excluding power supply) for any class should be reduced pro rata from the charges presented in Exhibit KCH-20 to reflect the reduced revenue requirement.

<u>MOBILE HOME PARK RATE SCHEDULE</u>

Q. What issue are you addressing regarding the rate schedule applicable to mobile home parks?

A. TEP has a special rate schedule applicable to mobile home parks that are master metered, called Mobile Home Park Electric Service – GS-11F. However, this rate schedule does not allow any "new" customers to join, including *existing* master-metered mobile home parks that happen to be on rate schedules other than the mobile home park rate. This restriction preventing existing mobile home parks from switching to this rate schedule is unjust and unreasonable and should be removed from the TEP tariff.

In this general rate case, TEP is changing the name of rate schedule GS-11F to "Mobile Home Park Electric Service (GS-M-F)." However, the rate schedule as proposed continues to include restrictive language that states it is "only available to premises *historically* served on a master metered mobile home park tariff" and that is it is "not available to new facilities." [Emphasis added]. The restrictions in the new language are also unreasonable and should be removed.

Q. Please explain why the restrictions on migrating to this rate schedule should be removed.

A. Mobile home parks that are master metered are generally billed by TEP at a single meter for the entire mobile home park load. The mobile home park operator then delivers the power to its individual residents over its own distribution system and, if sub-metered, bills the residents for their respective usage based on meters attached to each residence.

Significantly, the bills that mobile home park operators pass through to their residents are governed by state statute. Specifically, Arizona Revised Statute § 33-1413.01 provides that master-metered mobile home parks that are sub-metered must not charge their residents more than the utility's prevailing rates for basic single family *residential* service. Because of this statute, it is important that there be a reasonable nexus between what TEP charges a master-metered mobile home park for power and what TEP charges a residential customer for power, because the mobile home park operator can only pass on the latter charges to its residents. If the average rates charged to master-metered mobile home parks are greater than the rates charged to residential customers, then the mobile home park operator will be unfairly harmed by being forced by the TEP tariff to purchase power from TEP at one rate and then required by state statute to resell it at a lower rate. Such a situation would be unreasonable on its face.

Q. Is the situation you are describing an actual problem or simply a hypothetical problem?

A. This situation is an *actual* problem. Master-metered mobile home parks that, for whatever reason, are not served under the mobile home park rate are forced to take service under rate schedules that have no nexus to residential rates. I know of at least one master-metered mobile home park that is taking service under the LGS-13 rate schedule. This rate schedule, unlike current residential rates – and unlike the mobile home park rate – has a very substantial demand charge. While the LGS-13 demand charge may be reasonable for the vast majority of customers taking service under that rate schedule, it is <u>not</u> reasonable for a customer who must resell its power at residential rates. The rate design mismatch between LGS-13 and residential rates is causing an undue penalty assessed on mobile home park operators who must resell power to residents at rates that are below the rates that the operator pays TEP.

I have illustrated this problem for a hypothetical mobile home park taking service on LGS-13. This analysis is presented in Exhibit KCH-21. The example assumes that the mobile home park has the average size and load factor of a mobile home park taking service under the mobile home park rate. The analysis shows that the average cost of service under the LGS-13 rate is 18.66 cents per kWh at current rates, whereas the average rate for residential service under the TE-R-01 rate schedule is 13.06 cents per kWh. If this customer were allowed to switch to the mobile home park rate, the costs would be much closer to the residential rate. However, the current and proposed TEP tariff forbids this customer from switching to the mobile home park rate. This prohibition is unjust, unreasonable, unduly discriminatory, and not in the public interest. Accordingly, this prohibition should be eliminated by the Commission.

Q. Does TEP have an explanation for the restrictions on the availability of the mobile home park rates in its tariff?

A. Yes. TEP cites to the Arizona Administrative Rules, which state, in relevant part:

R14-2-205. Master Metering

A. Mobile home parks -- new construction/expansion

1. A utility shall refuse service to all new construction or expansion of existing permanent residential mobile home parks unless the construction or expansion is individually metered by the utility. Line extensions and service connections to serve such expansion shall be governed by the line extension and service connection tariff of the appropriate utility.

TEP indicates that its restrictions are intended to avoid master-metered circumstances in the future.[44]

Q. Do you believe that TEP's existing or proposed restrictions on this rate schedule are a reasonable means for avoiding master metering in the future?

A. No. R14-2-205 already precludes new master metering in the future for mobile home parks *by requiring utilities to refuse service* to such new facilities. By the same token, if a master-metered mobile home park is already being served by TEP, it must be presumed to be an older facility that predates the prohibition on new master metering. If such a customer happens to be on the wrong rate schedule, no public interest is served in preventing this customer from switching to the mobile home park rate schedule intended for such customers.

Q. What is your specific recommendation to the Commission regarding the mobile home park rate schedule?

A. The applicability criteria for Mobile Home Park Electric Service – GS-11F should be amended to remove the restriction on service to new customers. Similarly, to the extent that TEP's proposed replacement rate schedule GS-M-F is adopted, the prohibition on "new facilities" should be removed, as it is superfluous and ambiguous. Further, the applicability criteria should be amended to remove any language that restricts this rate schedule to premises that have been *historically* served on a master metered mobile home park tariff, as this restriction unreasonably prevents an otherwise eligible customer from switching to this rate schedule from a rate schedule that is ill-suited for the customer. *At a minimum,*

[44] TEP Response to AECC Data Request 21.1(b), provided in Exhibit KCH-22.

the applicability criteria should be amended such that there is no restriction on migrating to this rate schedule for any existing master-metered mobile home park.

Q. Do you have any recommended guidance regarding this rate schedule as it pertains to its future rate design?

A. Yes. Care should be taken to ensure a reasonable going-forward nexus between the mobile home park rate and residential rates. For example, if residential rates are not subject to mandatory demand charges, then neither should the mobile home park rate be subject to them. The statutory restrictions on the rates at which master-metered mobile home parks must resell power require that TEP and the Commission be mindful of the relationship between the mobile home park rate and residential rates going forward.

LOST FIXED COST RECOVERY MECHANISM

Q. What is the LFCR mechanism?

A. The LFCR is an adjustor mechanism that allows TEP to recover certain revenues deemed to be "lost" due to energy efficiency ("EE") and distributed generation ("DG") programs. TEP proposed the LFCR in the last general rate case. The TEP proposal in that case was opposed by many parties, including AECC; however, a compromise was reached and a version of the LFCR was included in the 2013 Settlement Agreement that was approved by the Commission. Now, in this case, TEP proposes changes that would tilt the compromise negotiated in the last case further in the direction of the Company's initial proposal.

Q. What significant modifications to the LFCR mechanism is TEP proposing?

A. The LFCR mechanism is currently designed to permit recovery of a portion of transmission and distribution costs not recovered through base rates due to EE and DG savings. Currently, 50% of demand charge base rate revenue is excluded from the calculation of the LFCR mechanism, as is the entirety of generation-related revenue, purchased power and fuel costs, and customer charge revenue.[45]

As explained in the Mr. Jones's direct testimony, the Company is proposing to expand the costs eligible for recovery though the LFCR mechanism to include generation and fixed must-run fixed costs, as well as the remaining 50% of demand charge revenue currently excluded from the calculation.[46] Further, TEP proposes to increase the year-over-year cap from 1% to 2% due to the proposed expansion of LFCR-eligible costs.[47]

Q. Do you support TEP's proposed changes?

A. No. The LFCR mechanism adopted in the last general rate case was the product of difficult negotiations. I am not persuaded that an LFCR is needed in the first instance, and I particularly disagree with levying this charge on LGS customers, as a significant part of TEP's concern regarding these customers can be addressed through rate design. Therefore, not only do I disagree with TEP's proposed changes, but I also recommend that LGS customers be exempt from this charge going forward.

Q. Please explain how concerns about fixed cost recovery for larger customers can be addressed through rate design.

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[45] LFCR Mechanism Plan of Administration.
[46] Direct Testimony of Craig A. Jones, pp. 77-79.
[47] *Id.* pp. 79-80.

A. The premise for recovery of "lost margins" is to insulate the utility from the loss of fixed-cost recovery when customers conserve energy by participating in utility-sponsored energy efficiency programs. This erosion of fixed-cost recovery may occur because, for many rate schedules, a portion of fixed cost is recovered through the volumetric energy charge. Thus, if energy consumption declines, all other things being equal, fixed cost recovery from conserving customers on these rate schedules declines. This problem can be mitigated by recovering a greater proportion of fixed costs through the customer charge and demand charge. Indeed, TEP is proposing to increase both of these charges for LGS. For example, TEP is proposing to increase the LGS customer charge to $1,000 per month, a relatively high customer charge for customers of this size.[48]

Q. Doesn't energy conservation also enable a customer to reduce its billing demand?

A. Yes, but it is much more difficult for a customer to reduce its billing demand from conservation in the short term than its energy usage. This is particularly true given the structure of TEP's tariff, because the billing demand for LGS customers is subject to a 75% ratchet. This ratchet means that the billing demand in any given month cannot fall below 75% of the customer's greatest demand measured during the preceding eleven months – even if subsequent usage is reduced.

Q. How can TEP address fixed-cost recovery concerns through rate design?

[48] Currently the LGS-13 customer charge is $775 per month and the LGS-85 customer charge is $950 per month.

A. When TEP first requested the LFCR, the stated purpose was to recover delivery service costs that would otherwise be unrecovered when energy conservation or distributed generation occurs.[49] TEP's rates are unbundled; therefore, delivery service rates are already separately stated in the tariff. TEP's proposed delivery service rates consist of customer charges, demand charges, and energy charges. This structure should be changed. As I discussed in my testimony on unbundled rate design, the delivery service energy charges should be eliminated and TEP should recover all of its delivery service costs from demand-billed customers through the customer and demand charges. This rate design change would not only address fixed-cost recovery concerns, it would improve rate design. It is well understood that the cost of providing delivery service is driven by customer-related costs and demand-related costs – not energy-related costs. For this reason alone, TEP's delivery service charges should not have an energy-charge component for demand-billed customers.

Q. If LGS is excluded from the LFCR would other customers be forced to bear the LFCR-related costs "caused" by the larger customers?

A. Absolutely not. If a customer group is excluded from the LFCR mechanism, they would neither pay the LFCR *nor shift costs to other classes for recovery*. The only LFCR costs that should be recorded by TEP would be those directly attributable to the participating classes. Consequently, no costs would be shifted from non-participants to participants.

Q. Please summarize your recommendations concerning the LFCR.

[49] Docket No. E-01933A-12-0291, Direct Testimony of David G. Hutchens, p. 9.

A. TEP's proposals to expand the scope of the LFCR should be rejected. The limitations on the scope of this charge were critical to allowing the LFCR to be included in the 2013 Settlement Agreement approved by the Commission. Further, it is unnecessary and unreasonable for LGS customers to be included in the LFCR program, as concerns about fixed cost recovery from this customer class can be addressed through rate design.

PPFAC RATE DESIGN

Q. What PPFAC rate design issues are you addressing?

A. I am addressing TEP's proposal to modify the rate design of the PPFAC to a percentage adjustment rather than a kWh adjustment and to make this change monthly, rather than annually. I addressed revenue requirement issues concerning the PPFAC separately in my revenue requirement testimony.

Q. Please describe TEP's proposed rate design change for the PPFAC.

A. The PPFAC rate is currently adjusted annually and charged to customers on a per-kWh basis. TEP is proposing to adjust the PPFAC monthly using a twelve-month rolling average and to allocate the PPFAC costs on a percentage of the average base fuel rate as established in a general rate case. The monthly PPFAC charge is proposed to be a single percentage adjustment applied to all base fuel rates for all customer classes.[50]

Q. What reasons does TEP offer for these changes?

A. TEP suggests that a monthly reset of the PPFAC using a rolling twelve month average, combined with hedging, would make changes in the adjustor less

[50] Direct Testimony of Craig A. Jones, p. 77. See also Direct Testimony of Michael Sheehan, p. 42.

volatile.[51] TEP also indicates that changing to a single percentage adjustment better aligns the changes in fuel costs with each rate class's base fuel costs.

Q. What is your assessment of these proposals?

A. TEP's proposal to use a single percentage adjustment for the PPFAC is reasonable as the adjustment would be proportionate to each customer class's fuel costs. I support adoption of this change.

TEP's proposal to change to a monthly reset of the PPFAC creates rate uncertainty from month to month and is potentially problematic. Although I am disinclined to support this change on a standalone basis, I would not oppose this approach if it were adopted as a package in tandem with the 70/30 PPFAC risk sharing mechanism that I am recommending in my revenue requirement testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[51] Direct Testimony of Michael Sheehan, p. 43.

EXHIBIT KCH-20

AECC/Noble Solutions Recommended Unbundled LPS-TOU & 138kV Rates at AECC/Noble Solutions Rate Spread & TEP Requested Revenue Requirement

Line No.	Description	TEP LPS-TOU Proposed[1]	AECC/ Noble Solutions LPS-TOU Recommended	TEP LPS-138kV Proposed[1]	AECC/ Noble Solutions LPS-138kV Recommended
	(a)	(b)	(c)	(d)	(e)
1	Basic Service Charge Components ($/Cust./Mo.):				
2	Meter Services	$77.26	$486.04	$115.88	$336.51
3	Meter Reading	$0.78	$8.13	$1.18	$74.32
4	Billing & Collection	$12.59	$148.61	$18.88	$1,111.62
5	Customer Delivery	$1,909.37	$1,357.22	$2,864.06	$1,477.55
6	Total	$2,000.00	$2,000.00	$3,000.00	$3,000.00
7	Demand Charge Components ($/kW):				
8	Local Delivery (See Note 2)				
9	Summer On-Peak	$2.73	$3.26	$1.86	$0.02
10	Summer Off-Peak	$1.40	$3.26	$0.15	$0.02
11	Winter On-Peak	$1.41	$3.26	$0.56	$0.02
12	Winter Off-Peak	$0.40	$3.26	$0.40	$0.02
13	Generation Capacity				
14	Summer On-Peak	$9.68	$9.21	$9.70	$9.06
15	Summer Off-Peak	$5.50	$3.61	$6.75	$5.07
16	Winter On-Peak	$8.00	$6.16	$8.00	$6.50
17	Winter Off-Peak	$4.00	$1.07	$4.00	$2.93
18	Fixed Must-Run	$1.30	$1.46	$1.30	$1.54
19	Transmission Components (See Note 3):				
20	FERC Transmission Rate	$3.34	$3.39	$3.34	$3.19
21	Ancillary 1: System Control & Dispatch	$0.05	$0.05	$0.05	$0.04
22	Ancillary 2: Reactive Supply & Voltage Control	$0.18	$0.18	$0.18	$0.17
23	Ancillary 3: Regulatory & Freq Response	$0.17	$0.18	$0.17	$0.16
24	Ancillary 4: Spinning Reserve Service	$0.47	$0.48	$0.47	$0.45
25	Ancillary 5: Supplemental Reserve Service	$0.08	$0.08	$0.08	$0.07
26	Total Transmission	$4.29	$4.36	$4.29	$4.08
27	Total Demand Charges ($/kW):				
28	Summer On-Peak	$18.00	$18.29	$17.15	$14.70
29	Summer Off-Peak	$12.49	$12.69	$12.49	$10.71
30	Winter On-Peak	$15.00	$15.24	$14.15	$12.14
31	Winter Off-Peak	$9.99	$10.15	$9.99	$8.57
32	Energy Charge Components ($/kWh):	Delivery	Generation	Delivery	Generation
33	Summer On-Peak	$0.00710	$0.00710	$0.00710	$0.00710
34	Summer Off-Peak	$0.00710	$0.00710	$0.00710	$0.00710
35	Winter On-Peak	$0.00710	$0.00710	$0.00710	$0.00710
36	Winter Off-Peak	$0.00710	$0.00710	$0.00710	$0.00710
37	Power Supply Charges:				
38	Base Power Supply Charges ($/kWh)				
39	Base Power Supply Summer On-Peak ($/kWh)	$0.057760	$0.057760	$0.056544	$0.056544
40	Base Power Supply Summer Off-Peak ($/kWh)	$0.024415	$0.024415	$0.023901	$0.023901
41	Base Power Supply Winter On-Peak ($/kWh)	$0.053200	$0.053200	$0.052080	$0.052080
42	Base Power Supply Winter Off-Peak ($/kWh)	$0.020995	$0.020995	$0.020553	$0.020553
43	PPFAC (%) (See Rider-1 for current Rate)	Varies	Varies	Varies	Varies

Notes:
1. Data Source: Exhibit CAJ-3, pages 301 - 301-3; 302 - 302-3.

2. AECC/Noble Solutions Unbundled Delivery demand charge is designed such that the combination of Basic Service Charge and Delivery demand charge revenues are proportionate to Distribution costs. AECC/Noble Solutions calculated a flat per-kW Distribution rate for each TOU period and eliminated the Delivery energy charges (re-designated as Generation energy charges).

3. AECC/Noble Solutions utilized TEP's general approach to calculating the unbundled Transmission component, based on the 2015 TEP Transmission Expense Workpaper. However, AECC calculated the LPS and 138 kV Transmission components separately.

AECC/Noble Solutions Recommended Unbundled LGS Rates
at AECC/Noble Solutions Rate Spread & TEP Requested Revenue Requirement

Line No.	Description	TEP Proposed[1]	AECC/ Noble Solutions Recommended
	(a)	(b)	(c)
1	Basic Service Charge Components ($/Cust./Mo.):		
2	Meter Services	$38.63	$165.17
3	Meter Reading	$0.39	$2.72
4	Billing & Collection	$6.29	$51.13
5	Customer Delivery	$954.69	$780.98
6	Total	$1,000.00	$1,000.00
7	Demand Charge Components ($/kW):		
8	Delivery Charge (See Note 2)	$3.86	$1.93
9	Generation Capacity	$7.95	$13.25
10	Fixed Must-Run	$1.33	$1.66
11	Total Transmission (See Note 3)	$4.36	$4.36
12	Total Demand Charge	$17.50	$21.20
13	Transmission Charge Components ($/kW):		
14	FERC Transmission Rate	$3.39	$3.39
15	Ancillary 1: System Control & Dispatch	$0.05	$0.05
16	Ancillary 2: Reactive Supply & Voltage Control	$0.18	$0.18
17	Ancillary 3: Regulatory & Freq Response	$0.18	$0.18
18	Ancillary 4: Spinning Reserve Service	$0.48	$0.48
19	Ancillary 5: Supplemental Reserve Service	$0.08	$0.08
20	Energy Charge Components ($/kWh):		
21	Local Delivery - Summer	$0.02510	$0.00000
22	Local Delivery - Winter	$0.01780	$0.00000
23	Base Power Supply Charges ($/kWh):		
24	Base Power Supply Summer	$0.037325	$0.037325
25	Base Power Supply Winter	$0.033801	$0.033801

Notes:
1. Data Source: Exhibit CAJ-3, pages 220 - 220-2.

2. AECC/Noble Solutions Unbundled Delivery demand charge is designed such that the combination of Basic Service Charge and Delivery demand charge revenues are proportionate to Distribution costs.

3. AECC/Noble Solutions utilized TEP's approach to calculating the LGS unbundled Transmission component.

Functional Cost Alignment of AECC/Noble Solutions Proposed Unbundled Rates at AECC/Noble Solutions Rate Spread & TEP Requested Revenue Requirement Combined LPS-TOU and 138 kV Classes

Line No.	Description	LPS-TOU & 138 kV Total Costs [1]	Proportion of Total Gen. & Dist. Costs	LPS-TOU & 138 kV Revenue from AECC/Noble Solutions Recommended Rates	Proportion of Total Gen. & Dist. Revenue [2]
	(a)	(b)	(c)	(d)	(e)
1	Distribution (Demand and Customer)	$9,412,375	16.0%	$8,635,275	15.9%
2	Generation Capacity [3]	$43,863,092	74.6%	$40,450,858	74.7%
3	Fixed Must-Run	$5,494,874	9.3%	$5,065,211	9.4%
4	Total Distribution & Generation Costs	$58,770,342	100.0%	$54,151,345	100.0%
5	Transmission [4]	$12,295,982		$14,649,224	
6	Power Supply	$58,436,997		$58,436,997	
7	Total - All Functions	$129,503,320		$127,237,566	
8	Other Revenue Credit	-$2,259,167			
9	Net Cost to be Collected from Sales Revenue [5]	$127,244,153			

Notes:
1. Based on AECC/Noble Solutions corrected class cost-of-service study at TEP's proposed revenue requirement.
2. Differences between Col. (e) and Col. (c) are due to rate rounding.
3. Power Factor revenues, as well as AECC/Noble Solutions Generation energy charge of $0.0071/kWh, are considered Generation Capacity-related.
4. AECC/Noble Solutions utilized TEP's general approach to calculating the unbundled Transmission rate component.
5. The difference between the net cost to be collected from sales revenue and the Total - All Functions revenue is due to rate rounding.

EXHIBIT KCH-21

Mobile Home Park Illustrative Rate Comparison

Comparison of Average Residential Rates and Rates Paid by a Hypothetical Mobile Home Customer on Rate Schedule LGS-13

TEP Residential Rate Schedule	Current TE-R-01 Rates	TE-R-01 Service Billing Determinants	Revenues
Residential Service (TE-R-01)			
Basic Service Charge Single Phase Per Mo.	$10.00	4,175,628	$41,756,280
Basic Service Charge Three Phase Per Mo.	$15.00	3,442	$51,624
Sum First 500 kWh	$0.05620	762,703,189	$42,863,919
Sum 501-1,000 kWh	$0.06720	503,607,184	$33,842,403
Sum 1,001-3,500 kWh	$0.07980	518,920,086	$41,409,823
Sum>3,500 kWh	$0.08820	16,585,028	$1,462,799
Win First 500 kWh	$0.05620	929,496,499	$52,237,703
Win 501-1,000 kWh	$0.06520	367,506,796	$23,961,443
Win 1,001-3,500 kWh	$0.07810	177,513,099	$13,863,773
Win>3,500 kWh	$0.08710	4,632,713	$403,509
Miscellaneous Revenue			(45,552)
Subtotal Delivery Revenue			$251,807,725
Base Power Summer kWh	$0.035111	1,801,815,486	$63,263,544
Base Power Winter kWh	$0.031532	1,479,149,108	46,640,530
PPFAC Revenue	$0.003892	3,280,964,594	12,770,210
Subtotal Fuel Revenue			$122,674,283
Surcharges			
LFCR	0.8565%		$3,207,438
LFCR	0.2770%		$1,037,315
ECA	$0.000250		$820,241
REST	$0.013000		$42,652,540
DSM	$0.001916		$6,286,328
Subtotal Surcharges:			$54,003,863
Total Estimated Revenues:			$428,485,871
Average $ per kWh:			$\boxed{\$0.1306}$

Hypothetical Mobile Home GS-11F Customer	Current Rates TE-LGS-13 Rates	GS-11F Service Billing Determinants	Revenues
Large General Service (TE-LGS-13)			
Basic Service Charge Per Month	$775.00	12	$9,300
Demand Charge Per kW	$15.25	625	$9,531
Summer kWh	$0.01920	77,430	$1,487
Winter kWh	$0.01340	84,581	$1,133
Subtotal Delivery Revenue			$21,451
Base Power Summer kWh	$0.035111	77,430	$2,719
Base Power Winter kWh	$0.031532	84,581	2,667
PPFAC Revenue	$0.003892	162,011	631
Subtotal Fuel Revenue			$6,016
Surcharges			
LFCR	0.8565%		$235
LFCR	0.2770%		$76
ECA	$0.000250		$41
REST	$0.013000		$2,106
DSM	$0.001916		$310
Subtotal Surcharges:			$2,768
Total Estimated Revenues:			$30,236
Average $ per kWh:			$\boxed{\$0.1866}$

Data Sources:
1. Schedule H-5, Page 1, Bill Count
2. 2015 TEP Revenue Proof - Public

EXHIBIT KCH-22

Exhibit KCH-22

TEP's Responses to Parties' Data Requests Referenced in Testimony

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 09, 2016

AECC 3.1

Please refer to 2015 TEP Schedule G – COSS Competitively Sensitive Confidential, tabs Schedule G-3 and Schedule G-4. Please explain why Large Power Service customers are allocated line transformers costs (Accounts 368 and 595) in TEP's COSS, although the LLP-90 tariff indicates that, "The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load." Are LLP-90 customers otherwise credited for providing their own transformers? Please explain.

RESPONSE:

Most of TEP's LLP customers take service at voltage levels of 138,000 V and less. Since most of the LLP customers were grandfathered onto these LLP rates before the referenced language was added to the tariff, many of the existing customers are taking service at a variety of voltages. The tariff is written to address new customers that will be connected directly to a 13,800 V or 46,000 V system. Therefore, since the class will have a blending of new and old customers, some level of transformation is appropriately included in the rates for this class. As new customers are added and the embedded costs depreciate, this piece will contribute less to the rates for the class as a whole.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

AECC 3.2

Please refer 2015 TEP Schedule G – COSS Competitively Sensitive Confidential, the "Load Data" tab.

a. Please explain why TEP is applying the same loss factors to LPS load as Residential load, although, according to the LLP-90 tariff, LLP-90 is designated as Primary Service with a delivery voltage of not less than 13,800 volts. Does TEP contend that the same level of energy and demand losses (per kWh and kW) are incurred to serve customers at 13,800 volts and residential service voltage? Please explain.

b. Please explain why TEP is applying the same loss factors to energy and demand. Does TEP contend that energy and demand line loss percentages are the same? Please explain.

c. Please provide the line loss study that is the source of the Distribution loss factor of 7.14% and the Transmission loss factor of 5.62%.

d. Does TEP's line loss study indicate the loss factor(s) attributable to the Primary voltage distribution system? If so, please provide the Primary voltage energy and demand loss factors.

RESPONSE:

a. The current "grandfathered" customers receive service at a variety of voltages including secondary voltage. The current tariff language applies to any added load and requires that the customer be served at primary voltage. Nearly all of TEP's LPS customers were on the TEP system prior to the referenced language being included in the tariff. Therefore, the Company has applied its Distribution loss factor to the LPS Class

b.-d. The development of the factors used in this case are explained in the file LineLossMethodSummary.docx filed in support to Schedules G&H (see UDR 1.001). The current study did not provide different factors for energy and demand. The file 2015 TEP Line_Loss_Summary Confidential.xlsx (see UDR 1.001), which provides the details of the study completed, was provided under the proper confidentiality agreements. The filed study considers transmission losses at 345 kV and distribution at TEP's 138 kV system.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO AECC THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 09, 2016

AECC 3.3

Please refer to 2015 TEP Schedule G – COSS Competitively Sensitive Confidential, tabs Schedule G-3 and Schedule G-4. Please explain why Large General Service customers are not allocated any Meters or Services costs (Accounts 369, 370, 586, 587, and 597).

RESPONSE:

The Company had not intended to exclude Metering and Service cost from the Large General Service class. The results for this correction are shown below. The Company will be filing a new Schedule G with this correction.

DESCRIPTION	TOTAL	RESIDENTIAL SERVICE	GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE POWER SERVICE	138kV	LIGHTING
CORRECTION							
RATE OF RETURN ON RATE BASE[1]	5.52%	-1.58%	19.22%	4.52%	13.38%		-15.82%
(ORIGINAL COST RATE BASE)							
RETURN AT PRESENT RATES	$116,218,763	($17,985,962)	$93,883,970	$10,945,808	$30,438,666	$0	($1,063,719)
FILED POSITION							
RATE OF RETURN ON RATE BASE[1]	5.52%	-1.60%	19.35%	4.61%	13.37%		-15.82%
	(ORIGINAL COST RATE BASE)						
RETURN AT PRESENT RATES	$116,218,763	($18,328,443)	$94,083,779	$11,097,150	$30,429,996	$0	($1,063,719)

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

AECC 3.4

Please refer to the Direct Testimony of Craig Jones, page 21, lines 26-27, which states, "For distribution plant costs found in FERC Account Nos. 364 - 374 either all or a portion of the costs are customer related because they are caused by customers." Please explain why TEP's CCOSS, 2015 TEP Schedule G – COSS Competitively Sensitive Confidential, has allocated the entirety of Accounts 364 through 368 to customer classes based on NCP, despite classifying a portion of these accounts as customer-related. That is, please explain why TEP believes it is appropriate to allocate the customer-related portions of these accounts based on NCP rather than the number of customers.

RESPONSE:

After review of this question, the Company agrees with this change and would like to extend its review to identify all impacts. A new study with this change will be provided as soon as possible.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO AECC SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322 May 9, 2016

AECC 7.1

Please refer to TEP's response to AECC Data Request 4.04.

a. Does the TEP Marginal Cost Study 10-30-2015 Competitively Sensitive Confidential.xlsx file constitute the Minimum System Study that was used to derive the customer-related percentages on the "Cust%" tab of the 2015 TEP Schedule G - COSS Competitively Sensitive Confidential file?

b. If the answer to part (a) is affirmative, please provide a workpaper in Excel format demonstrating how these customer-related percentages are derived from data in the TEP Marginal Cost Study 10-30-2015 Competitively Sensitive Confidential.xlsx file.

c. If the answer to part (a) is negative, please provide the Minimum System Study, including all related workpapers in Excel format, and provide the derivation of the customer-related percentages from data in the Minimum System Study in Excel format.

RESPONSE: April 4, 2016

a. Yes

b. **REVISED: THE FILE LISTED BELOW CONTAINS COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT IS ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.**

REVISED TO LABEL FILE COMPETITIVELY SENSITIVE CONFIDENTIAL: Please see AECC 7.1 TEP Min System Study v3 10-21-2015-Comp-Sen-Conf.pdf, Bates Nos. TEP\021433-021452.

c. N/A

RESPONDENT:

Brenda Pries (a,c) / Edwin Overcast (b)

WITNESS:

Edwin Overcast

RESPONSE: May 9, 2016

b. Please see AECC 7.1 TEP Min System Study v3 10-21-2015 without HW.xlsx for a non-confidential version of the provided file in Excel format. The proprietary information of Black & Veatch has been eliminated in this version. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Brenda Pries (a,c) / Edwin Overcast (b)

WITNESS:

Edwin Overcast

Tucson Electric Power
Minimum System Study (Oct 2015)
Summary

Row No.	FERC A/C A	Description B	Count C	Installed Cost D	Weighted HW Index E	2015 Cost F	Minimum Unit Cost G	Minimum System Cost H	Customer Ratio I
1	364	Poles, Towers & Fixtures	78,094	$ 129,782,729	2.05	$ 266,620,563	$2,172.59	$ 169,666,243	63.64%
2	365	Overhead Conductors & Devices	30,010,103	$ 180,425,882	2.46	$ 444,194,749	$3.00	$ 90,009,711	20.26%
3	366	Underground Conduit							100.00%
4	367	Underground Conductors & Devices	37,435,254	$ 302,831,236	2.30	$ 697,504,479	$7.61	$ 284,871,651	40.84%
5	368	Line Transformers	83,198	$ 263,885,332	3.34	$ 880,186,632	$2,547.89	$ 211,979,352	24.08%

AECC 8.4

For each of the six customer classes in TEP's class cost of service study, please provide the following information, in Excel format. Please estimate if necessary.

a. The number of customers served at secondary, primary, and 138 kV voltage, based on adjusted test year billing determinants.

b. The kWh sales at meter delivered at secondary, primary, and 138 kV voltage, based on adjusted test year billing determinants.

c. For demand-billed classes, the adjusted test year kW billing determinants served at secondary, primary, and 138 kV voltage.

d. The average test year 4CP demand at meter served at secondary, primary, and 138 kV voltage.

e. The test year 1NCP demand at meter served at secondary, primary, and 138 kV voltage.

RESPONSE:

a. The table below are the number of bills by rate schedule who received a primary discount in the test period. Only one customer has dedicated service at 138 kV.

Rate Schedule	Bills with Primary Discounts
GS11	30
GS37	24
GS39	37
GS76	12
LGS13	309
LGS85	36
Total	448

b-e. The Company currently does not bill customers differently based on voltage and therefore does not have billing determinants or load research available as requested for the number of bills listed above or for any rate class other than the 138 rate proposed in this filing. The data request for the proposed 138 kV customer is currently presented in the Company class cost of service study and revenue proof.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

AECC 15.2

TEP's response to AECC Data Request 8.4 (a) was non-responsive. The question asked for the number of customers served at secondary, primary, and 138 kV voltage, based on adjusted test year billing determinants, for each of the six customer classes in TEP's class cost of service study. Instead, TEP provided the number of bills by rate schedule who received a primary discount in the test period. TEP provided no information regarding the service voltage of customers in the LPS (non-138 kV) class. Please provide the number of LPS (non-138 kV) customers served at secondary and primary voltage, based on adjusted test year billing determinants.

RESPONSE:

The Company believes the response provided to AECC Data Request 8.4 (a) was responsive. Only classes with customers large enough to utilize primary metering economically contain provisions allowing for a primary metering discount. The number of customers receiving that discount would represent the number of customers served with primary meters. Craig Jone's Direct Testimony indicated only one customer was served at the 138 kV level; therefore, all other customers were served at the secondary level. AECC is correct that the Company inadvertently left the LPS class off of the list. It was still being researched at the time the response was provided and was overlooked when the response went out.

For the 18 LPS customers during the test year, 9 customers were served at the primary level and 8 are served at the secondary level, with one additional customer being served at both the primary and secondary level.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

AECC 15.4

Follow up to TEP's response to AECC Data Request 8.5. Please confirm that only one LPS-TOU customer provides its own transformer in the test year.

RESPONSE:

Since the submission of the response to AECC 8.5 (which inadvertently omitted a statement stating the LPS class would require more time), the Company completed additional research for the LPS rate class and identified a total of 12 of the 18 LPS customers that own their transformers (one of the 18 is a non-TOU LPS customer being served with a customer owned transformer). Two of those 12 are being served by both customer owned transformers and Company-owned transformers. Including the 2 LPS-TOU customers that are being served by both Company and customer owned transformers, 8 of 18 LPS customers were served from Company owned transformers during the test year.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones

AECC 16.3

Alternative Generation Service Experimental Rider.

a. How did TEP determine that 30 MW should be the appropriate maximum participation level if the program is adopted?

b. Please provide any analysis that TEP has performed in support of the Company's proposed management fee of $.0040/kWh.

c. In reaching the decision to purchase a 75% interest in the Gila River Power Plant Unit 3, did TEP consider the extent to which the amount of the Gila River capacity that was purchased could have been reduced by adoption of the Alternative Generation Service Experimental Rider or similar program? If yes, please provide copies of the analysis or studies. If not, please explain why TEP did not consider reducing the amount of capacity purchased by implementing the Alternative Generation Service Experimental Rider or similar program.

d. In reaching the decision to purchase a 49.5% interest in Springerville Unit 1, did TEP consider the extent to which the amount of the Springerville 1 capacity that was purchased could have been reduced by adoption of the Alternative Generation Service Experimental Rider or similar program? If yes, please provide copies of the analysis or studies. If not, please explain why TEP did not consider reducing the amount of capacity purchased by implementing the Alternative Generation Service Experimental Rider or similar program.

e. In reaching the decisions to add $103 million in investments in utility-scale solar generation since 2012, as reported on p. 26 in the direct testimony of David G. Hutchens, did TEP consider the extent to which the amount of the incremental solar capacity that was acquired could have been reduced by adoption of the Alternative Generation Service Experimental Rider or similar program? If yes, please provide copies of the analysis or studies. If not, please explain why TEP did not consider reducing the amount of capacity added by implementing the Alternative Generation Service Experimental Rider or similar program.

RESPONSE:

a. Based on the size of TEP's system and the risks associated with such an offering, as shown by APS's estimated loss of $16.8 million between November 2012 and May 2015 for their AG-1 program, the Company believed 30 MW is sufficient capacity to offer in a 4 year pilot.

b. TEP used the management fee for the APS AG-1 program as a starting point and made necessary adjustments. Because APS experienced net losses of approximately $16.8 million between November 2012 through May 2015 for their AG-1 program, TEP felt the management fee needed to be greater than APS's to help cover costs associated with the program.

c. No. As shown in the 2014 IRP, even with the planned acquisitions of both the 75% interest in Gila River Unit 3 and the 49.5% interest in Springerville Unit 1 as well as the build out of utility scale generation resources, TEP was still short 200 MW in peaking capacity in 2015 growing to a deficit of 570 MW in 2018 with the retirement of San Juan Unit 2. In future IRP planning cycles, the Company would factor in any approved Alternative

Generation Service Riders based on the firm capacity commitments within these approved tariff structures as part of its future resource plans.

d. See the response to AECC 16.3 c above.

e. See the response to AECC 16.3 c above.

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

AECC 21.1

Mobile Home Park Electric Service – GS-11F.

a. Please define "new customers" as used in this rate schedule.

b. Please explain the rationale for not allowing new customers to take service under this rate schedule.

c. Assume that an existing master-metered mobile home park has been operating for ten years and takes service under the LGS-13 rate schedule. If this customer seeks to switch to the GS-11F rate schedule, would it be considered a "new customer" for purposes of the GS-11F rate schedule?

d. In determining the rate design and availability criteria for GS-11F, did TEP take into account the statutory requirement that master-metered mobile home parks must not charge their residents more than the utility's prevailing rates for basic single family residential service (Arizona Revised Statutes 33-1413.01)? If the answer is "yes", please provide any analysis that TEP conducted that took this statutory requirement into account when designing the GS-11F rate and determining its availability criteria. If the answer is "no" please explain why TEP did not take this statutory requirement into account.

e. In light of the statutory requirement that master-metered mobile home parks must not charge their residents more than the utility's prevailing rates for basic single family residential service, does TEP agree that it would be reasonable to offer a rate schedule designed specifically for customers subject to this statutory requirement? If yes, does TEP agree that it would be reasonable to remove the availability restriction on service to new customers? If TEP responds "no" to either of these questions, please explain the basis for TEP's disagreement.

RESPONSE:

a. The reference GS-11F has been replaced by the GS-M tariff. This tariff does not include a reference to "new customers". The tariff would not be made available to "new facilities". Any existing master metering facility would still be able to receive service under this tariff for their existing facilities.

b. Per the following AZ Administrative Code, R14-2-205, the Company wants to avoid master metered circumstances in the future.

R14-2-205. Master Metering

A. Mobile home parks -- new construction/expansion

1. A utility shall refuse service to all new construction or expansion of existing permanent residential mobile home parks unless the construction or expansion is individually metered by the utility. Line extensions and service connections to serve such expansion shall be governed by the line extension and service connection tariff of the appropriate utility.

2. Permanent residential mobile home parks for the purpose of this rule shall mean mobile home parks where, in the opinion of the utility, the average length of stay for an occupant is a minimum of six months.

3. For the purpose of this rule, expansion means the acquisition of additional real property for permanent residential spaces in excess of that existing at the effective date of this rule.

B. Residential apartment complexes, condominiums, and other multiunit residential buildings

1. Master metering shall not be allowed for new construction of apartment complexes and condominiums unless the building or buildings will be served by a centralized heating, ventilation or air conditioning system and the contractor can provide to the utility an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship.

c. Yes.

d. The master-metered mobile home park is the Company's customer since they are the entity the Company provides the bill to. The referenced statute is the responsibility of the master-metering customer, if they choose to bill the tenants of the mobile home park as sub-metered tenants. The amount billed to each tenant is the responsibility of the mobile home park, and, as such, must meet the requirements of the statute. The Company has no control over what the tenant receives as a bill; therefore, the referenced statute is not considered in the calculation of the rates charged to the non-residential customer. The rate being charged to the mobile home park is designed consistent with other non-residential customers of its size and service type.

e. The answer to the first question in this section is no. The Company does offer a residential rate to its customers. It is the mobile home park that chooses to sub-meter and must therefore abide by the statute. The restriction to "new facilities" is designed to be in compliance with the statute referenced in section b above.

RESPONDENT:

Craig Jones

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TWENTIETH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 19, 2016

STF 20.11

Cost of Service: Follow-up to UDR 1.085 - Average and Excess Demand ("AED") is defined using individual class NCP less average demand. On sheet AvgEx&4CP of 2015 TEP Schedule G – COSS Competitively Sensitive Confidential.xlsx row 21 shows the class 4 CP, row 25 shows the 4CP Allocator and row 23 shows the AED/4CP allocator. Rows 23 and 25 appear to be identical as confirmed on row 27.

a. Where are the class NCP used on this sheet?

b. Where are the class NCP used in the development of the AED&4CP allocator?

c. If there is an average demand component to AED then why is cell G23 equal to zero?

d. If there is an average component within AED then why does the Lighting class receive no allocation of fuel inventory on Schedules G-1 and G-2?

e. Please provide a calculation of the DPROD allocator using AED-NCP and the resulting Schedule G.

f. Please explain if the email dated October 13, 2015 provided in the UNSE case is still appropriate for the above situation.

RESPONSE:

a.-c. As explained in the referenced e-mail, the AED theory would typically use NCP to allocate excess and the Company used CP, therefore NCP is not shown in the tab AvgEx&4CP in the cost of service study. And as expressed in the e-mail, you are correct that if you use a peak to calculate excess demand and calculate the load factor on that peak the study produces the same outcome as the peak methodology.

d.-e Please see TEP's supplemental response to UDR 1.001 dated May 19, 2016.

f. For the most part, with the further changes incorporated in this response.

RESPONDENT:

Brenda Pries

WITNESS:

Craig Jones