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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 NOS. 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	E-01933A-15-0322 **STAFF'S CLOSING BRIEF**

Arizona Corporation Commission
DOCKETED
OCT 31 2016
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The Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission") hereby submits its post hearing brief in support of the Settlement Agreement dated August 15, 2016, ("Settlement Agreement" or "Agreement"). This brief also addresses the issues that were left unresolved.

I. INTRODUCTION.

On November 5, 2015, Tucson Electric Power Company ("TEP" or "Company") filed an application for an increase in its rates as well as for approval of (1) an updated rate design that included a new general service class, (2) modifications to its Purchased Power and Fuel Adjustment Clause ("PPFAC"), (3) amended rate mechanisms, (4) modifications to its Tariff, Rules and Regulations and other existing compliance requirements, and (5) a buy through rate tariff.[1] Among the more significant requests was a mandatory three-part rate for new distributed generation customers. The issues related to the Company's proposed change to net metering and rate design for new DG customers has been deferred to a Phase 2 hearing.

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[1] Ex. TEP-1 at 2-5 (Application).

In its application, TEP requested a revenue increase to its test year adjusted non-fuel revenue of $109.5 million.[2] TEP's requested retail revenues represent a 7 percent increase over the annualized revenue based on rates currently in effect.[3] The requested revenue increase was based upon a 10.75 percent cost of equity with the Company's capital structure composed of 54 percent long-term debt and 46 percent common equity[4] using a December 31, 2011 test year.[5]

A number of parties intervened in this proceeding including Arizonans for Electric Choice and Competition and Freeport-McMoran, Inc. (collectively "AECC"), Arizona Investment Council ("AIC"), Arizona Community Action Association ("ACAA") Arizona Public Service ("APS"), Arizona Solar Industries Association ("AriSEIA"), Department of Defense and all other Federal Executive Agencies ("DOD"), the Energy Freedom Coalition of America ("EFCA"), IBEW Local 1116 ("IBEW"), the Kroger Co. ("Kroger"), Kevin Koch, Nobel America Energy Solutions ("Noble"), Pima County ("Pima"), Bruce Plenk, the Residential Utility Consumer Office ("RUCO"), Southern Arizona Homebuilder's Association ("SAHBA"), the Sierra Club ("Sierra Club"), SOLON Corporation ("SOLON"); the Solar Energy Industries Association ("SEIA"), Southwest Energy Efficiency Project ("SWEEP"), the Alliance for Solar Choice ("TASC"), the Vote Solar Initiative ("VSI"), Walmart and Sam's Club West (collectively "Walmart") and Western Resource Advocates ("WRA"). On June 2, 2016, Staff, AECC, DOD, IBEW, RUCO, Sierra Club, SWEEP and WRA filed direct non-rate design testimony. Staff, AECC, ACAA, AIC, APS, DOD, EFCA, Mr. Koch, Kroger, Noble, RUCO, SOLON, SWEEP, VSI, Walmart and WRA filed direct testimony regarding rate design and cost of service on June 24, 2016. TEP filed its rebuttal testimony on June 25, 2016.

Staff made several recommendations pertaining to the Company's proposed rate base, expenses, revenues and net operating income resulting in a recommended revenue increase of no more than $49.4 million on adjusted fair value rate base ("FVRB").[6] Staff also recommended a capital structure of 51.31 percent long term debt and 48.69 percent equity for the test year ending

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[2] *Id.* at 4.
[3] *Id.*
[4] *Id.* at 6.
[5] *Id.* at 2.
[6] Ex. S- 1 at 6 (Mullinax Conf. Direct).

June 30, 2015.[7] Staff also recommended a cost of equity of 9.35 percent, an overall cost of capital of 6.68 percent.[8] Staff also calculated a rate of return of 0.0 per cent to 0.70 percent on the FVRB Increment[9] and a fair value rate of return ("FVROR") of 4.81 percent.[10] RUCO recommended a revenue increase of $17.387 million.[11] AECC proposed a base rate increase of approximately $60.9 million or $48.6 million less than that sought by TEP's application.[12] DOD recommended a non-fuel revenue requirement of $76.0 million.[13]

On July 28, 2016, Staff filed a notice of settlement discussions. The parties of record subsequently held settlement discussions on August 5, 2016. The settlement discussions were open, transparent, and inclusive of all parties to Docket who desired to participate. All parties to that docket were notified of the settlement discussion process, were encouraged to participate in the negotiations, and were provided with an equal opportunity to participate. The following parties were participants in some or all of the meeting: TEP, RUCO, AIC, SWEEP, APS, DOD, Kroger, Freeport Minerals, AECC, IBEW, Sierra, WRA, Wal-Mart, SOLON, VSI, EFCA, Noble, Pima and Staff.

The parties reached an agreement in principal on the revenue requirement only and filed a Notice of Filing Proposed Settlement Agreement. The Settlement Agreement was signed by Staff, TEP, RUCO, AECC, AIC, Freeport Minerals Corporation, Walmart, Sierra and WRA (collectively, "Signatories").

The purpose of the Settlement Agreement is to settle the revenue requirement portion of this docket. The Agreement did not resolve every issue in this case. Because the Agreement only resolved the revenue requirement, certain issues, such as class cost of service allocations, rate design, the Buy Through, the Lost Fixed Cost Recovery mechanism, the Purchase Power and Fuel Adjustor, and net metering remained unresolved. The Signatories, as well as all other parties, presented their respective positions in Surrebuttal testimony and at the hearing in this matter.

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[7] Ex. S-3 at 2 (Parcell Direct).
[8] *Id.* at 3.
[9] *Id.*
[10] *Id.* at 45.
[11] Ex. RUCO-4 at 4 (Michlik Direct).
[12] Ex. AECC-6 at 7 (Higgins Direct).
[13] Ex. DOD-3, Ex. MPG-1 (Gorman Direct).

Obviously, not every party was a signatory. The DOD urged rejection or modification of the Agreement because it disagreed with the agreed upon return on equity ("ROE") of 9.75 percent. The DOD witness Michael Gorman argued for a 9.50 ROE, a Fair Value Rate of Return ("FVROR") of 5.10 percent and a Fair Value Increment of ("FVI") of .018 percent.[14] SWEEP also opposed, concerned that the revenue requirement did not include sufficient energy efficiency program costs in base rates.[15]

II. TERMS OF THE SETTLEMENT AGREEMENT.

The Agreement addressed the following issues related to the revenue requirement:

A. Rate Increase.

The Agreement proposed that TEP receive a non-fuel base rate increase of $81.5 million over adjusted test year non-fuel retail revenues, reflecting a non-fuel revenue requirement of $714,022,900.[16] The average base fuel rate is to be set at $0.032559 to recover a total of $289,147,243 in base fuel revenues.[17] TEP's total revenue requirement will be $1,003,170,143.[18] The Signatories further agreed that the Company's jurisdictional fair value rate base ("FVRB") used to establish rates is $2,843,985,854, representing an average of the original cost rate base ("OCRB") of $2,045,203,460 and the replacement cost new less depreciation ("RCND") rate base of $3,633,027,972.[19]

B. Treatment Of The Proposed Purchase Of Springerville Unit 1.

TEP had originally proposed to recover approximately $15 million related to the purchase of Springerville Unit 1 ("SGS 1") through its Purchased Power and Fuel Adjustment Clause ("PPFAC").[20] The Signatories agreed that the recovery of this amount through non-fuel rates, represented a revenue neutral change to the agreed upon revenue requirement.[21] Of the recommended non-fuel revenues, $15,243,913 is contingent upon TEP purchasing a 50.5 percent

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[14] Ex. DOD/FEA-4 at 2 (Gorman Surrebuttal).
[15] Ex. SWEEP-2 at 2 (Schlegel Surrebuttal).
[16] Ex. TEP-3 at 3 (Agreement).
[17] *Id.*
[18] *Id.*
[19] *Id.*
[20] Ex. TEP-5 at 6 (Hutchens Rebuttal).
[21] Ex. TEP-3 at 3.

share of SGS Unit 1.[22] This portion of the rate increase will not be effective until after the purchase has been completed and a final Order has been issued.[23]

TEP also agreed not to request rate base treatment of the purchase price paid for the 50.5 percent share of SGS Unit 1 until its next general rate case.[24] The leasehold improvements associated with the 50.5 percent share of SGS 1 will be updated in the OCRB at the Net Book Value ("NBV") as of December 31, 2016.[25]

C. Cost Of Capital.

A capital structure comprised of 49.97 percent long-term debt and 50.03 percent common equity is proposed in the Agreement.[26] In addition, the Signatories recommended a return on common equity of 9.75 percent and an embedded cost of long-term debt of 4.32 percent, resulting in a weighted average cost of capital of 7.04 percent.[27] Also, the Signatories proposed a fair value rate of return of 5.34 percent, which includes a rate of return on the fair value increment of rate base of 1.00 percent.[28]

D. Depreciation And Amortization Rates.

The depreciation and amortization rates proposed by TEP, in its rebuttal testimony, are recommended by the Agreement for adoption, with the following exceptions: (i) the rates for San Juan Generating Station shall be adjusted to reflect a depreciable life of TEP's total investment, including the Balanced Draft project, at San Juan Unit 1, of six remaining years; (ii) $90 million of excess distribution reserves will be transferred to San Juan Unit 1 and (iii) a reduction to depreciation rates on TEP's distribution plant to offset the increase in depreciation expense for San Juan Unit 1.[29] As required by the Agreement, TEP filed, with its testimony in support of the Agreement, schedules setting forth the applicable depreciation and amortization rates, including those for San Juan Unit 1.[30]

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[22] *Id.*
[23] *Id.*
[24] *Id.* at 4.
[25] *Id.*
[26] *Id.* at 3.
[27] *Id.* at 4.
[28] *Id.*
[29] *Id.* at 4.
[30] *Id.*

E. Treatment Of The Headquarters Building.

TEP agreed that it will write down the NBV of its headquarters building by $5 million, resulting in a $5 million reduction to the total Company OCRB within 30 days of the issuance of a final order in this proceeding.[31] In return, the Signatories agreed that they will not seek alternative rate treatment or additional write-downs of the headquarters building in further rate proceedings.

F. Treatment Of Post-Test Year Plant.

Post-test year plant, in the amount of $49.6 million and post-test year renewable generation plant of $4.8 million that is verified and in-service as of June 30, 2016, shall be included in the Company's OCRB.[32]

III. THE SETTLEMENT AGREEMENT IS IN THE PUBLIC INTEREST AND SHOULD BE ADOPTED BY THE COMMISSION.

The Settlement Agreement was the collaborative effort, of parties with divergent interest, working to narrow the scope of the contested issues in this docket. During the settlement discussion, a significant number of intervenors engaged in open, transparent, and arm's length negotiations during a one day settlement conference. The diverse interests included Staff, RUCO, TEP, an investment council, consumer representatives, demand-side management ("DSM")/energy efficiency advocates, low-income consumer advocates, renewable energy advocates, labor unions, large/industrial users, competitive power producers and the mines.[33]

During negotiations, each participant was given a chance to advance the position of its respective client. Each of the signatories compromised on vastly different positions in order to reach agreement on the revenue requirement issues and further the public interest.[34]

The proposed Settlement Agreement resolves the revenue requirement. That the Settlement Agreement is in the public interest is echoed by all signatories. Elijah Abinah, Assistant Utilities Director, testified that the compromises made by the Signatories in reaching the proposed Settlement Agreement further the public interest. Similarly, David Hutchens, TEP's president, testified that "the

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[31] *Id.* at 4-5.
[32] *Id.* at 5.
[33] Ex. S-20 at 3 (Abinah Direct).
[34] *Id.* at 4; Ex. TEP-6 at 5 (Hutchens Settlement).

Settlement Agreement was in the public interest given the compromises made by the diverse group of participants.[35] RUCO noted that the Agreement was a good deal for ratepayers because the revenue requirement was lower than what was originally proposed by the Company and would save ratepayers money.[36] Kevin Higgins, speaking on behalf of AECC, testified that the Agreement represents a fair compromise on a specific set of issues and that the approval of the Agreement is in the public interest.[37] SAHBA, who was not a signatory indicated that it urged the Commission to approve the Agreement.[38] The IBEW, also not a signatory, stated that it agreed with an adjustment regarding payroll that was a part of the Agreement.[39]

Staff recommends that the Commission approve the Agreement.

IV. UNRESOLVED ISSUES.

A. Cost Of Service.

In this case, Staff entered into a Settlement Agreement regarding TEP's revenue requirement. Once the revenue requirement is established the next step is to determine how it should be recovered from the customer classes.[40] The Class Cost of Service Study ("CCOSS") is used to determine the approximate cost to serve each customer class and subclass.[41] In this case TEP prepared two cost studies. The Company prepared an embedded cost study for the test year, and a marginal cost study for residential and small general service customers to support improvements in the efficiency and tracking of cost for the two-part rate design.[42] TEP indicated that it is focused on allocating costs as fairly as possible based on the principle of cost causation.[43]

The Company asserts that there are three fundamental cost classifications that are the basis for cost causation: customers, demand, and energy, and that all costs incurred by the utility are directly or

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[35] Ex. TEP-6 at 5.
[36] Tr. at 1229:12-25.
[37] Ex. AECC-10 at 7 (Higgins Conf. Surrebuttal).
[38] Tr. at 84:14-16.
[39] Tr. at 95:8-16
[40] Ex. TEP-30 at 8 (Jones Direct).
[41] Ex. S-10 at 15 (Solganick Conf. Direct).
[42] Ex. TEP-30 at 11.
[43] *Id.* at 8.

in some cases indirectly related to one these classifications.[44] The NARUC Manual identifies three fundamental methods for allocation of demand related costs: Coincident Peal ("CP") methods, Non-Coincident Peak ("NCP") methods and Average and Excess Demand ("AED") methods.[45] Within each of these fundamental allocation methods, there may be multiple specific methods.[46]

In this case, the Company's CCOSS has changed since its prior rate case. In the prior rate case, the Company's CCOSS has six classes (Residential, Small General Service, Large General Service, Large Light & Power, Mining and lighting). In this case, the Residential, Small General Service and Lighting classes are similar.[47] The Company has created new rate schedules for Medium General Service ("MGS") and 138 kV based on demand and voltage criteria from the SGS and Large General Service ("LGS") and Large Power Service ("LPS") rate schedules respectively.[48] Staff believes these changes are appropriate, but does recommend in the Company's next rate case that the CCOSS should reflect the separation of the MGS from the SGS if the rate class is approved in this case, because the transition of customers to that rate class will have taken place.[49]

Although both the Company and Staff ultimately agree that the CCOSS is used as a guideline for allocation of revenue and rate design,[50] Staff is critical of certain aspects of the CCOSS that the Company submitted in this case. First, as it relates to the allocator that the Company used for "Other Production" expenses, Staff agrees with the Company's change from Peaks and Average allocator used in the last rate case to the AED allocator in this case. However, the Company's use of AED in conjunction with 4CP is non-standard. In other words, using coincident peaks, including four, within the AED allocator is not a standard or recommended methodology.[51] The result of this is that the values for the AED & 4CP and the 4CP allocator alone, are identical.[52] So while the Company asserts that it switched to the AED method because it was ordered in an Arizona Public Service case,

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[44] *Id.* at 18.
[45] *Id.*
[46] *Id.*
[47] Ex. S-10 at 16 (Solganick Conf. Direct).
[48] *Id.* at 16
[49] *Id.*
[50] Ex. S-10 at 15; Ex. TEP-30 at 8 (Jones Direct).
[51] Ex. S-10 at 18.
[52] *Id.* at 19.

the methodology used by the Company in this case is the functional equivalent of the 4CP method. The effects of the use of the 4CP allocator are shown in the Lighting class where no fuel inventory has been allocated even though under a true AED methodology there should be an average component and there is none.[53] Staff believes the appropriate methodology is the AED in conjunction with non-coincident peak ("NCP") as is supported by the NARUC manual. This allocator reflects both average load (energy) and excess load (demand) without becoming a CP allocator. The Company did provide a revised schedule G that incorporated the expected AED-NCP allocator along with changed to meter allocations and customer allocations.[54] The use of the DPROD allocation methodology, AED-NCP, increases the allocation of costs to lower load factor classes compared to the Peaks and Average methodology the Company used in the last CCOSS.

Second, TEP appears to allocate class income taxes on the sum of return times rate base plus operating expenses. With this methodology, positive taxes are allocated to a class that is not providing enough revenue to cover expenses.[55] The Company's use of this methodology magnifies the disparity between positive and negative class returns.[56] When all classes reach parity, this will not be an issue, but under present conditions the impact is significant.[57] An alternative methodology calculates class income tax based on the profitability of the class. Use of this method would lessen the impact to certain rate classes.

Ultimately there are two major occurrences at play in this case that magnify the individual impact on the rate classes. First, while the Company's net distribution plant has increased by 20 percent, net production plant has increased by 47 percent.[58] Second, the Company changed its production plant allocation methodology from Peak and Average to AED-NCP.[59] As a result, Staff recommends that the Company's CCOSS should only be used as a general guideline and, as is typical, utilized with the concept of gradualism in the class revenue allocation decision for this case.[60]

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[53] *Id.*
[54] Ex. S-10 at 20 (Solganick Direct).
[55] *Id.* at 21
[56] *Id.*
[57] *Id.* 22.
[58] *Id.*
[59] *Id.*
[60] *Id.*

B. Revenue Allocation.

In determining the appropriate revenue allocation of revenue to each class, Staff believes the Commission should consider the relative position (from the CCOSS) of the classes along with the qualitative issues such as economic conditions for consumers, the business climate for commercial and industrial customers and past practices. In considering these criteria, Staff utilized the following criteria:[61]

- The individual rate classes should be gradually moved toward a Unitized Rate of Return ("UROR") of 1.000 over one or more rate cases depending on the frequency of rate cases and the distance of the class' UROR from 1.000.
- The should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue.
- There should be a lower bound of 50 percent for any class' increase compared to the overall increase.

In addition, Staff believes consideration should be given to the Company's purchase of the combined cycle generating unit. It was purchased to stabilize energy costs, which benefits all customers.[62] Staff believes that it would be inappropriate to reduce rates for any customer class because that would send a confusing message about the plant expenditure.[63]

Staff modeled the Settlement revenue increase of $81.5 million several ways by allocating the revenue increase as follows:[64]

- Equal percentage increase (across the board by revenue);
- Moving all of the classes to the same return (UROR equals 1.000);
- Moving the Residential, LGS and Lighting classes 50 percent of the amount needed to reach parity (and increase all other classes by $23 million);
- Moving the Residential, LGS and lighting classes 70 percent of the amount needed to reach parity (and increase all other classes by $0.07 million);
- Moving the Residential, LGS and Lighting classes 65 percent of the amount needed to reach parity (and increase all other classes by $5.9 million);
- Moving the Residential, LGS and Lighting classes 60 percent of the amount needed to reach parity (and increase all other classes by $11.7 million);
- Moving the Residential, LGS and Lighting classes 55 percent of the amount needed to reach

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[61] *Id.* at 23.
[62] *Id.*
[63] *Id.*
[64] Ex. S-12 at 8 (Solganick Conf. Surrebuttal).

parity (and increase all other classes by $17.5 million);

- Moving the Residential, LGS and Lighting classes 45 percent of the amount needed to reach parity (and decrease all other classes by $29.1 million);
- Moving the Residential, LGS and Lighting classes 40 percent of the amount needed to reach parity (and increase all other classes by $35 million);
- Moving the Residential, LGS and Lighting classes 35 percent of the amount needed to reach parity (and increase all other classes by $40.8 million);
- Moving the Residential, LGS and Lighting classes 30 percent of the amount needed to reach parity (and increase all other classes by $46.6 million.

Under all of these scenarios, the remaining revenue requirements from the other classes (GS, LPS and 138kV) were allocated based on their respective revenues.

Based on this modeling, the updated CCOSS, the principles discussed above, the impact of the purchase of the Gila River combined cycle plant, the change in allocation methodology and the relative impacts between classes, Staff recommends that the revenue requirements be allocated by increasing the Residential, LGS and Lighting classes 50 percent of the amount to reach parity and increasing all other classes by $23.3 million.[65] Under this allocation, the Residential class receives 66.9 percent of the overall $81.5 million settlement revenue increase.

Based on the Schedule H-1, in the Company's Rejoinder,[66] the Company is proposing to allocate the $81.5 million increase with 63.7 percent or $51,880,337 to the Residential class, -4.8 percent or ($3,947,034) to the General Service class, 34.10 percent or $27,794,996 to the Large General Service class, 5.21 percent or $4,244,682 to the Large Power Service class, .75 percent or $614,515 to the 138 kV class, and 1.12 percent or $912,515 to the Lighting class.

Staff, on the other hand, is proposing to allocate the $81.5 million dollar increase with 66.9 percent or $54,501,050 to the Residential class, 18.9 percent or $15,420,669 to the General Service class, 3.8 percent or $3,070,470 to the Large General Service class, 0.7 percent or $591,468 to the Lighting class, and the remainder allocated to the Large Power Service and 138 kV classes.[67]

Staff's allocation will bring the UROR for the rate classes closer to parity or 1.00 with the Residential class having a 0.363 return, General Service having a 2.656 return, Large General Service

[65] *Id.* at 11.
[66] Ex. TEP-32 at Schedule H-1 (Jones Rejoinder).
[67] Ex. S-12 at Ex. HS-6.

having a 0.798 return, LPS class having a 1.020 return. As indicated above, Staff's long term plan is that rates should be based on costs derived from the CCOSS,[68] but that it will take more than one rate case to accomplish this goal. The Company has generally accepted most of Staff's revenue allocations except the Company believes less revenue should be allocated to the LPS and 138 kV class.[69] The important difference between Staff's proposed revenue allocations and the Company's is that with Staff's allocations, no one customer class is receiving a decrease. This is important, because it more accurately reflects the acquisition of the combined cycle plant that benefit all rate classes. Staff's proposal will also allow completion of removing the subsidies in the following rate case.[70]

C. The LFCR Should Not Be Modified At This Time.

In its 2012 rate case, the Company proposed an LFCR similar to that approved by Arizona Public Service in Decision No. 73183 and for UNS Gas in Decision No. 73142.[71] The Company asserted then that it needed an LFCR to *mitigate* the negative financial impacts of complying with the Commission energy efficiency rules and the rising number of distributed generation resources in its service territory resulting from the Renewable Energy Standard Tariff Rules.[72] Ultimately, the settlement agreement approved adopted an LFCR that is

> intended to recover a *portion* of distribution and transmission costs associated with residential, commercial and industrial customers when sales levels are reduced by EE and DG and *not* to recover lost fixed costs attributable to generation and other potential factors, such as weather or general economic conditions.[73]

In this case, the Company is seeking to fundamentally change the LFCR from its original purpose. TEP is seeking to update the LFCR to allow recovery of 100 percent of the lost fixed costs attributable to generation, 100 percent of lost demand revenues, eliminate the LFCR Fixed Cost Option, increase the year-over-year cap from 1 percent to two percent, and modify the percentage-based adjustment to be a single rate applied to the customers' bill rather than two separate rates for

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[68] *Id.*at 11.
[69] Ex. TEP-32 at 4.
[70] Ex. S-12 at 12.
[71] Decision No. 73912 at 8 (June 27, 2013), Docket No. E-01933A-12-0291.
[72] *Id.*
[73] *Id.* at 6.

EE and DG.[74]

TEP's rationale for the inclusion of generation related costs is that since its last rate case, the level of EE and DG has increased as has the level of unrecovered fixed costs necessary to provide safe, reliable service.[75] Regarding the inclusion of all of the demand related distribution cost, the Company asserts that because the calculation of these lost fixed costs identifies the actual amount of the offset to the customer's peak demand, the LFCR should include 100 percent, not the current 50 percent.[76]

The basis for the Company seeking to eliminate the LFCR Fixed Cost Option is simply that to date no customers have signed up for this option.[77] Staff supports this change to the LFCR since no customer has used this option.[78]

On the issue of increasing the year-over-year cap to 2 percent, the Company asserts that this change is necessary if 100 percent of the generation and the remaining 50 percent of the distribution demand is included in the LFCR.[79] In other words, this change is only necessary if generation and the remaining 50 percent of demand is included.

Finally, the Company's reason for combining EE and DG into one rate is to "simplify" the percentage-based LFCR adjustment.

Except as noted above regarding the elimination of the LCFR Fix Cost Option, Staff is opposed to all of TEP's proposed changes to the LFCR.[80] The LFCR when originally approved was only intended to mitigate, not necessarily eliminate all lost fixed costs associated with demand, and more importantly specifically excluded the recovery of generation costs.[81] Staff believes that generation is fungible, and is not affected by EE and DG if the energy is instead delivered to a new customer, an existing customer using slightly more energy, an economic development customer or

[74] Ex. TEP-30 at 77-80 (Jones Direct).
[75] *Id.* at 78.
[76] *Id.* at 79.
[77] *Id.*
[78] Ex. S-10 at 53 (Solganick Direct).
[79] Ex. TEP-30 at 79
[80] Ex. S-10 at 53.
[81] Decision No. 73912 at 26.

sold off system.[82]

Importantly, the Company's Firm Load Obligations shows increasing requirements in Net Retail Demand, which is net of DG and EE. It shows a trend of increasing total number of customers and further shows increasing sales to retail customers, and the Company's Firm Wholesale Requirements are also forecasted to increase starting in 2017.[83]

Staff also has a concern that if the Company's proposed Economic Development Rider and changes to the LFCR are approved that it could create a circumstance where some generation costs could be double collected.[84] Specifically, Staff is concerned that the Company could bill existing customers for the generation costs within the LFCR mechanism, and up redirecting that energy and capacity to a new residential customer or a customer attracted by the proposed economic development rates, which could cause a double collection.[85]

Further, if a buy through rate is adopted in this case, Staff does not believe it is appropriate to recoup lost revenues due to the approval of a buy-through rate in this case. It would be inappropriate to charge all customers, subject to the LFCR, for benefits that to those few customers that are fortunate enough to be on the buy-through tariff.[86]

Importantly, the Commission in the recent UNSE rate case declined to approve the Company's identical changes to the LFCR for that company. In this case, TEP asserts that the fixed costs associated with its generation fleet are much larger on both a relative and absolute basis.[87] However, there is nothing in the UNSE decision that indicates the size of UNSE's generation fleet was even a relevant factor considered by the Commission in rejecting the UNSE's proposed changes.[88] Finally, the inclusion of generation and the remainder of the demand lost fixed costs will more than double the amount collected through the LFCR.[89] According to the Company it would go

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[82] Ex. S-10 at 54.
[83] *Id.*
[84] *Id.* at 55.
[85] *Id.*
[86] *Id.* at 56.
[87] Ex. TEP-32 at 5.
[88] Decision No. 75697 at 126 (August 18, 2016), Docket No. E-04204A-15-0142.
[89] Ex. S-12 at 54 (Solganick Surrebuttal).

from collecting \$17.9 million to \$25.7 million through the LFCR.[90] Staff does not believe this is appropriate, and expands the LFCR beyond its original purpose.

D. Rate Design.

1. Monthly service charge.

In its original application, TEP requested an increase in its monthly service charge for residential customers, from \$10.00 to \$20.00.[91] Staff and the majority of the parties opposed this change. Staff recommended, in its Direct testimony, an increase of \$17.00.[92] For SGS customers, the Company is requesting an increase in the Basic Service Charge from \$16.50 and \$17.50 (TOU) to \$30.00.[93]

For LGS rate customers, the Company is requesting an increase in the customer charge from \$775.00 and \$950.00 (TOU) to \$1,000.00. Staff recommended that The Basic Service Charge should remain at its present level, as the charge requested by the Company is not supported by the unit costs.

In Staff's Surrebuttal testimony, Staff recommended a reduction in the basic service charge for standard residential customers to \$15.00 and \$12.00 for non-standard residential customers, based on the Company's revised cost of service study.[94]

In its rejoinder testimony, the Company agreed to the following: (i) a \$15 per month basic service charge for standard residential customers; (ii) a reduced charge of \$12 for the non-standard residential customer; (iii) a \$27 basic service charge for standard Small General Service ("SGS") customers; and (iv) a reduced rate of \$22 for non-standard SGS customers.[95] Staff is in agreement with these charges.

While Staff and the Company agree that the appropriate methodology to use to determine the monthly service charge is the Minimum System Method, RUCO, SWEEP/WRA, VSI and EFCA advocated for the use of the Basic Customer Method.[96] The Minimum System Method includes

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[90] Tr. at 2777:15-22.
[91] Ex. TEP-30 at 43.
[92] Ex. S-10 at 29 (Solganick Direct).
[93] Ex. TEP-30 at 46.
[94] Ex. S-12 at 12 (Solganick Surrebuttal).
[95] Ex. TEP-32 at 3 (Jones Rejoinder).
[96] See Ex. SWEEP/WRA – 3.

distribution costs when used to calculate the monthly customer charge. The Basic Customer Method is the method that classifies customer related costs to only those that are directly altered by the number of customers on the system. These costs generally include customer service, meter billing or the service drop.[97] Both Staff and the Company agree that inclusion of distribution costs are appropriate because those distribution assets must be available to service peak demand and thus, those costs should be included in the basic service charge.[98]

2. *Reduction in the number of tiers.*

TEP proposed to eliminate the third and fourth tiers of the residential rate. Company witness Jones testified that the third and fourth tiers add no cost-based value to the rate class other than exacerbating the issues of fixed cost being inequitably recovered from the higher usage customers.[99] He further stated that eliminating the upper rate tiers results in a more cost-based rate design.[100]

Staff supported the elimination of the third and fourth tiers. According to Staff witness, Howard Solganick, the existing third and fourth tiers should be eliminated and the remaining inclination should be flattened as the residential customer's load factor increases as usage increases, which does not support inclined rates.[101]

Initially, SWEEP and WRA did not support the elimination of the tiers. However, SWEEP/WRA witness Brendon Baatz, testified that it could support having three tiers in the residential rate.[102] RUCO recommended that the fourth tier be eliminated, retaining the third tier, believing that the elimination of the fourth tier would have minimal customer impact.[103]

By eliminating the third and fourth tier and the small increase in the monthly service charge, the impact within the LFCR will be lessened.[104] Staff supports the Company's proposal and recommends that the third and fourth tier be eliminated.

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97 Tr. at 471:10-14.
98 See discussion Tr. 2349-353.
99 Ex. TEP-30 at 45.
100 *Id.*
101 S-10 at 29.
102 Tr. at 466:23-25.
103 Ex. RUCO-10 at 24 (Huber Direct).
104 S-13 at 12 (Solganick Surrebuttal).

3. *Staff recommends approval of TEP's proposed medium general service class.*

As part of the Company's proposal for rate class changes, the TEP is seeking to create a new MGS class that will have a minimum and maximum kW level. It is the Company's assertion that that the creation of this class will allow the largest of the SGS customers to move to a more similarly sized, homogeneous rate class that will include a demand charge.[105] The Company is also proposing to establish a new 138 kV rate that will be offered to only those customers with the ability to take service at this transmission level voltage or greater.[106]

According to the Company, the new MGS class will contain approximately 3,600 former SGS customers, and 93 former Large General Service ("LGS") customers.[107] To qualify for the MGS class, the customers must have a minimum demand of greater than 20 kW, or a combined total of 24,000 kWh or more in any two consecutive months.[108] Further, the Company asserts that these new MGS rates (standard and TOU), will be essentially the same as the current LGS rates with a 75 percent ratchet, winter/summer differentiated rates and a single tier rate.[109]

The Company is proposing a $40 basic service charge for the MGS class with a 300 kW cap.[110] Any customer that exceeds that 300 kW cap for a second billing month in a 12-month rolling period will automatically be moved, in the subsequent month to the LGS rate class.[111] Since the MGS class uses a three part rate with a demand component and ratchet, and most of the customers that will be moved to this rate will have previously been on a more typical two part rate, the Company is taking several steps to mitigate the impact that this new rate structure will have on those customers. First, the Company is proposing multiple forms of communication for those customers that will be affected, and has developed plan to inform those customers before being moved to the new class. Second, the Company proposes a transition period that will allow 9 months for the customer to adapt to a demand charge before it is actually reflected on the bill.[112] The Company

[105] Ex. TEP-30 at 33.
[106] *Id.* at 33.
[107] *Id.* at 37; Tr. at 2781.
[108] Ex. TEP-30 at 37.
[109] *Id.*
[110] *Id.* at 47; Ex. TEP-31 at 13 (Jones Rebuttal).
[111] Ex. TEP-31 at 13.
[112] *Id.* at 15

indicated it would not oppose expanding that period to a full 12 months.[113] Third, the Company is cognizant that there are a handful of accounts that are extremely counter seasonal, and is proposing to modify the MGS tariff to include a seasonality clause.[114] The Company is proposing to add a provision that will apply to those full requirements customers who consume 90 percent or more of their kWh during the winter period. This includes: waiving the ratchet mechanism, waiving the MGS cap, and applying section 7.C.7.g. Finally, the Company is proposing that this seasonal rate only apply to full requirements customers.[115]

Staff supports the establishment of the MGS class as proposed by the Company with the safeguards proposed. Staff recommends that the Company be required to develop and implement an MGS cost of service class in its next rate case to verify the costs to be used in the future MGS rate design.[116] Staff recommends that the Company provide consumption and interval data to MGS customers free of charge for a period of six months after the mandatory transition of MGS customers.[117] Further since changes to rate design may have unintended results for "outlier" or "non-normal" MGS customers, and the imposition of a demand ratchet (if approved) may also have unforeseen impacts, Staff recommends that the Commission should keep the rate design portion of this rate case open for at least 18 months after the completion of the transition to MGS rates.[118]

4. Buy through proposals.

In its Application, TEP proposed as a pilot program a new "buy through" tariff to comply with Decision No. 74689 (August 12, 2014)[119] issued in Docket No. 14-0011, the UNS Energy and Fortis Inc. ("Fortis") merger Settlement Agreement. Formally referred to as Experimental Rider-14 Alternative Generation Service ("AGS") ("ER-14"), TEP's buy through tariff, if approved, would be for an initial four (4) year term and be available to customers with a peak load of 3,000 kW or more at a single service point and served under Large Power Service rates LPS-TOU or LPS-TOU-HV.[120]

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[113] Tr. at 2779
[114] Ex. TEP-31 at 15.
[115] *Id.*
[116] Ex. S-10 at 34.
[117] *Id.* at 46.
[118] *Id.* at 35
[119] Ex. TEP-1 at 6:11-13 (Application).
[120] *Id.*; Ex. CAJ-3 at Sheet No. 714.

Total program participation would be limited to 30 MW of customer load and, in the event applications for service exceed the maximum program load amount, customers would be selected through a lottery process.[121] Under the buy through tariff, a successful customer would select a TEP-approved "Generation Service Provider" ("GSP").[122] TEP would then contract with the GSP to receive delivery of and title to the power on behalf of the customer.[123] In addition to Generation Service and Energy Imbalance Service charges and a hedging cost, TEP would also receive a monthly Management Fee of $0.0040 per kWh to a customer's metered kWh.[124]

A customer may to return to the Company's Standard Generation Service under its applicable retail rate schedule without charge if (1) the customer provides TEP with a minimum one year notice; or (2) ER-14 is discontinued at the end of the 4-year experimental period; or (3) the Commission terminates the program prior to the end of the experimental period.[125] Absent any one or more of these conditions, TEP would be obligated to use its best efforts to provide a customer with generation service at the Dow Jones Electricity Palo Verde Daily Index price or an equivalent for the power delivery date plus $20/MWh until the Company is reasonably able to integrate the customer back into its generation planning and provide power at the applicable retail rate schedule.[126] A returning customer would be required to remain with the Company's Standard Generation Service for at least one year and compensate the Company for all fixed generation costs avoided by the customer during the period the customer was receiving service under this rider.[127]

TEP opposes implementation of the buy through tariff and proposed it only because it was required by Decision No. 74689.[128] The Company, through its witness, Craig Jones, asserts that the buy through tariff "allows certain larges customers to "cherry pick" currently available capacity resulting from short-term energy market conditions and will ultimately result in costs being shifted to

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[121] Ex. CAJ-3 at Sheet No. 714.
[122] *Id.* at Sheet No. 714-1.
[123] *Id.*
[124] *Id.* at Sheet No. 714-2.
[125] *Id.* at Sheet No. 714-3.
[126] *Id.* at Sheet No. 714-3.
[127] *Id.*
[128] Ex. TEP-30 at 6.

the remaining customers."[129] Similarly, the Company opposes any variation of a buy through tariff that results in costs being shifted to either TEP or other customers[130] and further submits that any non-fuel shifts in cost resulting from any potential buy through should at a minimum be recovered through the LFCR if not directly from the benefitting entities.[131]

Several intervenors support the approval of a buy through tariff such as TEP's ER-14, a modified form thereof, and/or suggest alternative versions. AECC, Noble, Wal-Mart and Kroger, all proponents of a buy through, argue that such mechanism provides them with choices for their electricity purchases, and submitted suggestions for the Commission's consideration. Most notably, AECC,[132] through its witness, Kevin Higgins, recommends adopting a buy through program "that is as similar as reasonably possible to the AG-1 program currently in effect in the APS service territory."[133]

Mr. Higgins favors adopting some of the features of ER-14 and modifying others to make the program open to a wider variety of customers and a more viable option.[134] Among other things, Higgins recommends increasing the proposed 30 MW cap to 60 MW, increasing the minimum load size of 3000 kW (peak demand), allowing aggregation of smaller loads in the LGS class owned by the same corporate entity to meet the 3000 kW threshold, continuing the program term 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, reducing the monthly management fee to \$0.002/kWh from the proposed \$0.004/kWh, limiting the going-forward charges for generation-related services to a charge for reserve capacity applied to 15 percent of the customer's billing load (instead of the proposed 100 percent of the customer's billed demand), use of the first \$7,550,207 of any revenue requirement reduction apportioned to the classes eligible for the buy through program to absorb TEP's revenue deficiency ascribed to the loss of fixed generation revenues from buy through

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[129] Ex. TEP-30 at 6; Ex.TEP-31 at 9 (Jones Rebuttal).
[130] Ex. TEP-31 at 9.
[131] *Id.* at 9; 76.
[132] As acknowledged by its witness, Greg Bass, Noble jointly supports and offers the testimony of AECC witness Higgins regarding the buy through programs at issue herein. Ex. NS-13 at 4 (Bass Direct).
[133] AECC-8 at 3 (Higgins Direct Rate Design).
[134] *Id.* at 4.

customers (thereby holding both TEP and the ineligible customer classes harmless from adoption of the buy through), and reducing the $20 per MWh mark-up to $4 per MWh for customers wanting to return to standard generation service without providing the proposed one-year notice to the Company.[135]

In response to issues raised and comments made in the Commission's August 10, 2016, Open Meeting regarding the buy through program he proposed on behalf of AECC in the UNS Electric general rate case (Docket No. E-04204A-15-0142), Mr. Higgins has also submitted an alternative buy through proposal for Commission consideration.[136] The "five-year-opt-out buy-through" is similar to a program implemented in the Portland General Electric service territory in Oregon[137] though that program is direct access, not a buy through.[138] This alternative program requires participating customers to pay a transition adjustment associated with their buy through loads for a five-year transition period, after which such customers would continue to receive buy through service without any further generation charge obligations to TEP except for unbundled fixed must-run generation charges.[139] Higgins submits that, as proposed, the five-year opt-out would necessarily be a permanent program, not a limited-term pilot, given that participating customers would have to pay five-years of transition charges then bear the risks associated with market pricing.[140]

AECC, through its witness, Michael McElrath, submitted a third buy through-type alternative for use at Freeport-McMoran's Sierrita mining operation, i.e., a franchise agreement modeled after a Commission approved agreement between Phelps Dodge, Safford, Inc. ("PD Safford"), Morenci Water & Electric Company ("MW&E") and Graham County Electric Cooperative, Inc. ("Graham") regarding electric service to Freeport's mining operations in Safford, Arizona.[141] Characterized as a stand-alone program, the franchise option would be in addition to the two buy through options proposed by Mr. Higgins.[142]

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[135] *Id.* at 4-6.
[136] Ex. 10 at 9:15-17 (Higgins Surrebuttal).
[137] *Id.* at 3.
[138] *Id.* at 11.
[139] *Id.* at 10.
[140] *Id.* at 10.
[141] Ex. AECC- 14 at 10-11 (McElrath Surrebuttal); Tr. at 1707:3-10.
[142] Ex. AECC-14 at 13; Tr. at 1707:11-16, 1745:6-10.

Walmart, through its witness, Chris Hendrix, recommends approval of ER-14 with several modifications. Mr. Hendrix proposes to raise the participation limit to 250 MW, reject the $0.004/kWh management fee and require TEP to file a cost-justified proposal, reduce the minimum participation limit to 1000 kW and allow corporate aggregation to meet this threshold, permit all classes to participate in the program, eliminate ER-14 participant responsibility for any of the Company's generation related charges, and put no limit on the term of the program.[143] Mr. Hendrix disputes Mr. Jones' claim that the buy through would allow customers to "cherry pick" available capacity and asserts that the existence of an AGS program does not harm any non-AGS customers.[144]

Kroger also supports approval of the proposed ER-14 with some modifications. Stephen J. Baron appeared on behalf of Kroger and recommends that corporate aggregation should be permitted to meet the minimum 3000 kW requirement, the $0.004/kWh management fee should be reduced unless TEP can provide evidence to support it, and the participation limit should be increased to 65 MW commensurate with the corresponding cap in APS' AG-1 program.[145]

Staff does not object to the adoption of ER-14 provided there are no adverse impacts or costs to all other customers.[146] This would include impacts on TEP which could ultimately come back through and impact customers.[147] Staff witness, Howard Solganick, opined that there has been ample evidence offered on the positive impact on those customers either adept or lucky enough to utilize the buy through but not on what the possible impact would be on other non-participating customers as a direct result of that program.[148] Mr. Solganick added that he is not yet "comfortable" with any of the buy through alternatives propounded in this docket, because of the potential adverse effect to a particular class.[149]

Staff is also concerned that buy through customers may return to TEP service when the market becomes tight (expensive) and thus impact other customers that cannot or will not use this

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[143] Ex. Walmart-4 at 5-8 (Hendrix Direct Rate Design).
[144] *Id.* at 9.
[145] Ex. Kroger-1 at 25-27 (Baron Direct).
[146] Ex. S-10 at 47; Ex. S-12 at 20.
[147] Tr. at 2335:4-8.
[148] Tr. at 2416:13-20, 2456:5-11.
[149] Tr. at 2434:8-11, 2435:3-7.

mechanism.[150] These customers would include, most notably, all residential, SGS and proposed MGS customers, i.e., those too small to be cost efficiently managed due to the additional billing needed to account for the mechanism and some larger customers who qualify but opt out due to internal costs or inexperience in an unregulated market.[151] In essence, ER-14 may help choose winners and losers within the business community.[152]

Staff is also opposed to the Company recouping any allegedly lost buy through revenue and/or any deferral of allegedly lost buy through revenue, including recouping lost incremental revenues through the LFCR.[153] Staff submits that, since ER-14 is not available to all customers, it appears that its benefits would flow through only to those customers able to use the buy through and it would be inappropriate to charge all customers for benefits that accrue primarily to only a select few.[154]

Staff would further submit that it is presently uncertain to what degree, if any, adoption of ER-14 or any other proposed buy through program would adversely affect other TEP customers. However, AECC has acknowledged that eligible customers who qualify for the lottery would be better off than those of the same class that do not.[155] AECC has also acknowledged that customers of the same eligible class who opt out and/or are not chosen to participate would help fund the buy through but asserts that those customers would be better off under Mr. Higgins' proposal than under any other party's revenue allocation.[156] As previously noted, Staff's stance on adoption of a buy through is premised on the lack of any adverse effect or cost on any other customer. AECC's contention that eligible customers who qualify for but opt out of the program and/or are not chosen in the lottery are still better off rate wise than they would have been absent the buy through does not eliminate the fact that other customers would be adversely affected by its adoption. Staff would suggest that this factor be taken into consideration by the Commission when deciding whether to

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[150] Ex. S-12 at 20
[151] *Id.* at 20-21
[152] *Id.* at 21.
[153] Ex. S-10 at 47.
[154] *Id.*
[155] Tr. at 1009:3-8.
[156] Tr. at 1023:10-22, 1025:1-5.

adopt a buy through. It is also important to note that the Commission did not approve a buy through in the UNSE docket.

5. Prepaid tariff.

In its Application, TEP proposes a Prepaid Energy Service ("Prepay" or "PES") tariff intended to provide customers with another option to manage their energy costs.[157] As proposed, PES customers will be able to prepay an amount toward their electricity use (in lieu of receiving and paying a monthly bill), "track and receive feedback about their energy usage, costs and other information to save money and energy"[158] and thereby have a greater awareness and control over their energy consumption, and bypass certain deposits and fees usually required to guarantee payment.[159] According to the Company, the Prepay program is a stand-alone tariff exclusive of certain other pricing options and will be available to all residential customers except those whose service address depends on electrical devices for health-related reasons.[160]

Benefits of the Prepay program promoted by the Company include: waiver of the customer residential service deposit for surety of payment and reconnection/disconnection field service charges, no assessment of late payment fees for non-payment, participants will not be required to pay off past due balances in order to participate when using a 75/25 debt reduction plan, access to daily energy use information to help understand and control energy usage, access to customizable low balance alerts to assist customers in managing energy use and payment scheduling, and Company provided energy efficiency tips and education materials.[161] Customers with outstanding balances would be eligible to enroll in the PES plan by either paying off their outstanding balance prior to enrollment or participating in the 75/25 debt reduction plan whereby 75 percent of each payment would be applied to their prepaid energy bill and 25 percent applied toward reducing their outstanding balance.[162] TEP posits that non-participating customers also benefit indirectly from the incremental improvement in customer-facing technology required to implement such service and the

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[157] Ex. TEP-1 at 6; Ex. CAJ-3 at Sheets 108 to108-2.
[158] Ex. CAJ-3 at Sheets 108 to 108-2.
[159] Ex. TEP-33 at 6:5-6 (Smith Direct).
[160] *Id.* at 6.
[161] *Id.* at 7.
[162] *Id.* at 7.

expected reduction in customer bad debts and related costs and write-offs which are routinely recovered through rates charged to all customers.[163]

TEP has also proposed to incorporate in the Prepay program protections for medically fragile and other vulnerable customers similar to those provided by APS's program. These include: non-enrollment for any customers known to have significant medical conditions or who require the assistance of electrically powered medical devices, non-enrollment for customers who have not acknowledged that they understand the terms and conditions of the PES agreement, provision of a Prepay Service Agreement and Welcome Packet containing educational information about energy efficiency opportunities and available incentives, Company provided balance alerts via a customer's preferred communication channel (phone, text or email) and low balance alerts when their prefunded energy balance falls to $19 and below, disconnections will only occur after a grace period followed by a No Credit Disconnect alert[164] no less than two hours before an actual disconnection would occur,[165] no disconnections during extreme weather events, and TEP provided documented disconnection histories to limited-income customers to support bill assistance applications.[166]

ACAA opposes the PES program due to there still being significant unexplored issues with the results of the APS program upon which it is based.[167] In particular, ACAA contends that the disconnect effect is likely underreported and reported savings attributable to prepaid metering may just be a coincidental result from the decreased consumption of low-income customers.[168] ACAA also disputes the Company's characterization of the program as "optional" or "voluntary" claiming that, while no one would be directly forced into joining the program, when a customer cannot afford a deposit, they are offered the "choice" of prepaid electricity versus no electricity.[169] ACAA further contends that prepaid electricity is primarily offered to low-income customers which suggests the

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[163] *Id*.at 7-8.
[164] As noted by TEP witness Smith, the Company has requested the ability to provide a No Credit Disconnect alert and seeks a waiver of A.A.C. R14-2-211 which requires a written notice prior to disconnection.
[165] *Id.* at 9.
[166] *Id.* at 8-9.
[167] Ex. ACAA-1 at 14 (Zwick Direct).
[168] *Id.*
[169] Ex. ACAA-2 at 19 (Zwick Surrebuttal).

beginning of offering a "second class service" to customers unable to afford deposits.[170] ACAA claims that prepaid customers buy power more frequently than post-paid customers which, when the additional fees incurred for such payments are combined with the proposed $5 increased fixed charge and travel costs to payment stations are considered, a customer may save energy, but is unlikely to save money.[171] ACAA asserts that Prepay customers should be offered a discount for participation, not charged more for joining that program.[172] ACAA also objects to the four hour "grace period" proposed after a No Credit Disconnect notice is given claiming such provision is likely to result in additional charges and costs to those least able to afford them.[173] ACAA submits that it is dangerous to cut off electricity to a household and it should only be done as a last resort, not automatically as a backstop for utility collections.[174]

ACAA also objects to TEP's proposal to include the PES program in its Energy Efficiency ("EE") implementation plan due to the lack of data to back it up.[175] ACAA asserts that deprivation is not conservation and should not be counted toward the Company's EE plan.[176] Ms. Zwick opined that there appeared to be some inconsistencies in the Company's assertions regarding the Prepay program including the inference that it would not be viable economically if it is doesn't receive the EE designation.[177]

SWEEP also opposes the Prepay tariff[178] as not being in the public interest.[179] SWEEP generally does not support Prepay tariffs as a stand-alone because they end up being harmful to low income customers.[180] However, SWEEP contends that, if the PES tariff is approved, it should reflect

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[170] Ex. ACAA-1 at 14-15; Ex. ACAA-2 at 23; Tr. at 615:1-12, 631:7-10.
[171] Ex. ACAA-1 at 15; 24-25; Tr. at 613:24-614:9.
[172] Ex. ACAA-1 at 15.
[173] *Id.* at 15; 25.
[174] *Id.*
[175] Tr. at 625:18 -626:1.
[176] Ex. ACAA-1 at 27.
[177] Tr. at 611:1-8.
[178] SWEEP treats this issue as two distinct offerings to customers: the prepay tariff and the prepay "program" which encompasses the "enhanced customer education information and behavior feedback program." SWEEP contends that the "program" should be covered in TEP's EE implementation plan proceeding and asserts that the Company (Smith Rejoinder) agrees. Tr. at 555:6-13.
[179] Ex. SWEEP/WRA-1 at 30 (Baatz Direct); Ex. SWEEP/WRA at 21 (Baatz Surrebuttal).
[180] Tr. at 554:6-8, 13-16.

cost savings to TEP and allow Lifeline discounts for low income customers.[181] SWEEP/WRA's witness Brendon Baatz recommends modifying the Prepay rate by lowering the monthly service charge and discounting the volumetric energy rate.[182] In addition, SWEEP has concerns that the Prepay program will pose significant risk to elderly and limited-income customers because of the potential for immediate electrical service cutoff for nonpayment, the lack of steady income for some customers and their lack of understanding the consequences of nonpayment.[183] Mr. Schlegel emphasizes that it is imperative for these programs to be implemented for only those customers for whom pre-payment is a reasonable and appropriate option.[184] Toward that end, SWEEP notes that consumer protections are essential and that the PES program and tariffs not be used solely as a utility revenue collection strategy.[185]

SWEEP also contends that it is premature to make a determination as to whether the Prepay program should qualify as EE given the lack of adequate and appropriate energy conservation/management education and usage feedback.[186] Given this, SWEEP believes the issue of Prepay as EE should be addressed in TEP's EE implementation plan process, not in this rate case.[187]

Staff is not opposed to the Prepay program provided it is offered as a pilot program for at least twenty-four (24) months.[188] TEP, through the rebuttal testimony of its witness, Denise Smith, agreed to offer the PES as an optional pilot program.[189] ACAA witness Ms. Zwick related that ACAA still opposes the program and requests its denial but further states that, if it were approved by the Commission, it should as a pilot program.[190]

In its rebuttal testimony, TEP modified upward the proposed kWh rates which would be applicable to the Prepay program. The first Energy Delivery rate to be assessed in both summer and

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[181] Ex. SWEEP/WRA-1 at 31-32.
[182] *Id.* at 3.
[183] Ex. SWEEP-1 at 14 (Schlegel Direct); Ex. SWEEP-2 at 6 (Schlegel Surrebuttal).
[184] Ex. SWEEP-1 at 14.
[185] *Id.*
[186] *Id.* at 15.
[187] *Id.*
[188] Ex. S-16 at 5, 20 (Connolly Direct).
[189] Ex. TEP-33 at 3 (Smith Rebuttal).
[190] Ex. ACCA-2 at 18.

winter for the first twenty (20) kWh per day was increased from \$0.064000 to \$0.065000 and the second rate of \$0.079000 to be applied to kWh over twenty (20) per day was increased to \$0.084000 from \$0.079000.[191] The proposed PES also now includes a \$17.00 monthly BSC to match the Basic Residential fee and includes \$5 equipment and systems adders bringing the total monthly fees/charges to \$22.00.[192] Because TEP is unable to determine when in the daily billing cycle a Prepay customer would move from one energy rate to the next, the Company is proposing to use a weighted average of the Residential Electric Service ("RES") energy rates to calculate the first tier energy rate for the Prepay program; the energy rate for the second tier would be equal to the proposed second tier RES energy rate. This proposal results in a slightly higher first tier energy rate for the Prepay program than the RES.[193]

In response to TEP's proposals, Staff recommends reducing the BSC for standard residential rates from \$17.00 to \$15.00 and revising the first tier energy rate to \$0.064008 and the second tier energy rate to \$0.080588.[194] In addition, irrespective of the possible difficulties TEP may encounter in determining when a customer moves to the next energy tier, Staff believes there should be no difference in the energy rates charged in the Prepay program and RES, especially because the former would be a pilot program[195] and this would reduce customer confusion.[196] Staff posits that, as the Company will be able to review the RES rate structure at the end of the pilot program, should it be able to prove it can accurately determine when a customer moves into the higher kWh usages, Staff would recommend that Prepay rates equal the RES.[197] If not, the PES should equal the RES first tier energy rate for all kWh usage.[198]

In addition, Staff continues to object to TEP's proposal to include the Prepay program as part of its 2016 EE portfolio. Staff maintains that the PES is a billing option, not an EE program as the perceived energy conservation may simply be a result of customers running out of money and being

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[191] Ex. S-17 at 1 (Connolly Surrebuttal).
[192] *Id.*
[193] *Id.* at 2.
[194] *Id.* at 2.
[195] *Id.*
[196] *Id.* at 3.
[197] *Id.*
[198] *Id.*

disconnected.[199] TEP has asserted that if the Prepay program is not approved as part of its EE portfolio, the data management tools may not be made available. It is Staff's understanding that the Company plans to charge a $2.00 fee for those same tools and thus is not a basis for including the program as part of its EE portfolio.[200]

Staff is open to the possibility that Prepay customers may be willing to voluntarily modify their energy usage with conservation efforts. However, Staff believes that TEP should use Staff's proposed twenty-four month pilot program to generate data to prove this point.[201] Interestingly, as grounds for disputing Staff's position, TEP asserts that "there is a strong case to be made that Prepay is very similar to other behavioral...[EE] programs" and that it is ultimately a policy decision for the Commission as to whether Prepay provides EE savings and should be included in the Company's next EE Implementation Plan.[202] However, TEP then references its proposed third party evaluation process that is intended to identify and verify savings which are separate from disconnection.[203] This is consistent with Staff's proposal to use the data generated from the pilot program to make such assessment, albeit before Prepay is made a part of the Company's EE Implementation Plan.

Moreover, in addressing ACAA concerns regarding the methodology used to evaluate energy conservation in other Prepay programs, TEP acknowledges that "this rate case asks only for approval of the program as a billing option [and that] the proper venue for debating the Prepay program's merits as an energy conservation program is within the DSM planning process."[204] Given this, Staff strongly believes that the Commission should utilize the twenty-four months of Prepay pilot program data to determine whether that program results in EE before it's made a part of the Company's EE Implementation Plan.

In sum, Staff's recommendations for the Prepay program are as follows:

- The program be approved as a Pilot Program for at least twenty-four months;
- If TEP proves it is able to accurately determine when a customer moves into the higher

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[199] *Id.* at 4.
[200] *Id.*
[201] *Id.*
[202] Ex. TEP-35 at 2 (Smith Rejoinder).
[203] *Id.*
[204] *Id.* at 4.

usage kWh, the energy rates for the program should equal the energy rates of the RES. If TEP is unable to accurately determine when a customer moves into the higher usage kWh, the energy rate for the program should equal the first tier energy rate of the RES for all kWh usage;

- The program exclude customers relying on an electrical device for medical survival;
- The program not be included in TEP's EE portfolio;
- TEP receive a waiver from providing a written disconnect notice as required under A.A.C. R14-2-211(D) for purposes of this program;
- TEP Lifeline customers be allowed to participate in the program;
- TEP modify it Prepay Service Agreement in accordance with Staff's recommendations and file it with Staff for analysis, review and approval prior to the implementation of the program;
- TEP should provide to Staff the third-party evaluation of the Prepay program within sixty (60) days of the completion of the evaluation. TEP should also include its recommendation as to whether the Prepay program should be implemented on a permanent basis, continue as a Pilot program for an extended period of no more that the next rate case decision, or be discontinued;[205]
- Inclusion of a $5 adder to cover the costs of equipment and system implementations for the program;[206] and
- The inclusion of Section 20 of the Prepay Service Agreement which addresses the closing of Prepay accounts due to nonpayment.[207]

6. Low income.

In its last rate case, the Company began a transition to the inclusion of Lifeline customers on existing residential rates, but with a fixed Lifeline discount. Under this concept, Lifeline customers can easily determine their discount and the impact on their bills if their financial situation were to improve. The existing $9.00 Lifeline discount for these Lifeline customers is simple to understand and administer.[208] However there are still legacy Lifeline customers (some dating from the mid-1990s with substantial discounts) and there are multiple configurations of the Lifeline discount (27).[209] The Company is proposing to increase the discount to $15.00 and further consolidate the 27 rates to five available to new and existing customers and 5 that would apply to existing customers.[210] For existing frozen Lifeline rate customers the Company is proposing use a flat monthly $15 discount[211] from the standard residential rates and in some cases also reduce the Basic Service Charge

[205] Ex. S-17 at 5-6 (Connolly Surrebuttal); Ex. TEP-34 at 5 (Smith Rebuttal); Tr. at 2884:22-25.
[206] Ex. S-17 at 3.
[207] *Id.* at 4.

in order to approximate the existing subsidies and limit the increase to an amount similar to non-Lifeline customers.[212]

7. *Grandfathering.*

In conjunction with the Company's proposed changes to net metering and rate design for partial requirements customers, the Company was also asking that existing net metered customers that have submitted completed applications for interconnection to TEP's facilities prior to June 1, 2015, be grandfathered and stay on the existing Net Metering Rider R-4 for a period not to exceed twenty years.[213] Although this matter has been bifurcated, wherein issues related to proposed changes to net metering and rate design for new DG customers are deferred to a Phase 2 of the evidentiary hearing following a final decision in the Value of DG docket, the issue of grandfathering was addressed in this phase of the proceeding.[214] During the hearing although the Company did not withdraw its June 1, 2015 grandfather date, it also acknowledged that based on the outcome in the recent UNSE rate case regarding grandfathering that it would not oppose a grandfather date that coincides with that effective date of the rate order in this case.[215]

8. *Adjustors.*

a. Purchased Power Fuel Adjustment Clause (PPFAC).

In its original application, TEP requested the following changes to its PPFAC: (1) to implement a monthly change in the rate (which is currently recalculated only annually) and (2) to allocate these monthly adjustments to the PPFAC costs on the same percentage basis to all rate classes. Company Witness Jones states, "The PPFAC charge will be a single percentage adjustment applied to all base rates for all customer classes."[216] In addition, Company Witness Sheehan

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[208] Ex. TEP-30 at 58 (Jones Direct).
[209] *Id.*
[210] *Id.* at 57.
[211] *Id.*
[212] *Id.* at 59.
[213] Ex. TEP-21 at 19 (Dukes Direct).
[214] August 22, 2016 Procedural Order at 2.
[215] Tr. at 664-66.
[216] Ex. TEP-30 at 77.

discusses the Company's proposed change to make the PPFAC a rolling average. The Company's current PPFAC includes a component called the base cost of fuel rate that is established in a base rate case and, therefore, will be set in this case. This base cost of fuel rate is fixed until changed by approval of the Commission in a subsequent base rate case.

The current PPFAC includes two components that are established outside a rate case: the forward component and the true-up component.[217] The forward component is set annually in a PPFAC filing made by the Company and as ordered by the Commission.[218] The last PPFAC filed by TEP was February 1, 2016.[219] The forward component is a projection of fuel and purchased power costs for the upcoming 12- month period.[220]

The true-up component is, as its designation suggests, the difference between the previous 12-month forecast component and the actual purchased power and fuel costs the Company incurred during that previous 12-month period.

The first of the Company's PPFAC proposals is to alter the frequency by which the PPFAC rate is changed. The frequency change is from annually to monthly. This change would remove the forward component's 12-month projection of costs in favor of calculating a historical 12-month rolling average.[221] The Company states that the reason for the proposed change is to smooth the volatility of fuel costs for customers.[222]

The second change proposed by the Company was to modify the allocation of the increase or decrease to the monthly recalculated PPFAC rate from cents per kWh to a single percentage basis across all customer classes.[223]

Staff did not support the changes to the PPFAC as proposed by TEP.[224] Staff recommended that the PPFAC remain as a calculation of cents per kWh. There was no evidence presented to suggest that customers would benefit from changing to the Company's proposed plan.

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[217] Ex. S-5 at 3 (McGarry Rate Design Direct).
[218] *Id.*
[219] *Id.*
[220] *Id.*
[221] Ex. TEP-24 at 42 (Sheehan Direct).
[222] *Id.* at 42: 25-26.
[223] Ex. TEP-30 at 77.
[224] Ex. S-5 at 7.

During the hearing, Staff witness Robey testified that TEP was withdrawing its request for changes to the PPFAC.[225]

b. Environmental Cost Adjustor (ECA).

The ECA is an adjustor mechanism that allows TEP to recover capital carrying costs and incremental O&M costs related to environmental investments made by TEP and not already recovered in base rates or recovered through another Commission approved adjustment.[226] TEP proposed a pro-forma adjustment to operating expenses to remove all revenues collected under the ECA mechanism. These revenues were not collected as part of base rates, so they must be excluded from Test-Year revenues in order to calculate new base rates. Staff was in support of this adjustment.[227]

TEP further proposed to increase the ECA cap from 0.25 percent of prior test-year annual revenues to 0.50 percent of annual revenues year-over-year, as well as convert the collection of the ECA from an energy-based charge to a percent-based charge. Staff opposed the changes to the ECA.[228]

c. Demand Side Management Adjustor and Renewable Energy Standard Tariff.

TEP proposed a revenue requirement adjustment which reduced operating income by $28.478 million for the REST and DSM.[229] These pro-forma adjustments were associated with removing test year revenues and expenses recovered through the adjustors from the Company's operating income. Staff was in support of these adjustments.[230]

With respect to the DSM Plan, Staff recommends that in TEP's next DSM Plan, TEP reassess its billing charge so that all customers, both residential and non-residential are billed based on an energy-based charge.[231] Staff recommends that the Company update its DSM Plan of Administration ("POA") so that it is consistent with all existing decisions. This final POA should be submitted for

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[225] Tr. at 1460:5-12.
[226] Ex. S-9 at 2 (Van Epps Direct).
[227] Id. at 3.
[228] *Id.* at 4.
[229] *Id.* at 3-4
[230] *Id.*
[231] Van Epps Surrebuttal, Ex. S-22 at 3-6.

Commission approval within 60 days of a decision in this matter.[232]

With respect to the Company's REST, Staff recommends that the Company file a POA for its REST adjustor consistent with the POA filed for UNS Electric, Inc. Staff further recommends that the POA incorporate all existing pertinent Commission decisions. This final POA should be submitted for Commission approval within 60 days of a decision in this case.[233]

TEP testified that these Staff recommendations were acceptable.[234]

9. White Mountain.

The White Mountain solar facility ("White Mountain"), also known as project D12PD41 Springerville Generating Station 10MW Expansion, is located 6 miles west of the Springerville Generation Station along the main access road to the power plant. White Mountain is 100 percent owned by TEP and was placed in service in December of 2014.[235] The total unburdened cost of the facility, including the interconnection, was $43,193,061.40.[236] The output from the facility is used for station use, primarily to power the well-field pumps.[237] The megawatt rating/maximum output of White Mountain is 8.25 MWac.[238]

During the course of the on-going Value of Distribution Generation ("DG") docket (Docket No. E-00000J-14-0023), the production issues associated with White Mountain surfaced with the Company's provided production data and Staff's calculated capacity factor.[239] The substantially low capacity factor drew Staff's attention, especially when compared to the other major facilities in the Company's solar portfolio.

Staff requested that the Company continue to provide information monthly about the production of the facility (both White Mountain and the pre-existing SGS solar facility) until a final decision in this matter, so that Staff can monitor the performance of the facility. The Company

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232 *Id.*
233 *Id.*
234 Smith Rejoinder Test., Ex. TEP-35 at 2.
235 Ex. S- 18 at 2 (Liu Direct).
236 *Id.*
237 *Id.*
238 *Id.*
239 *Id.*

testified that it would provide such information to Staff.[240]

10. RPS credit option.

In its Application, TEP proposed a new net metering rider with three-part rates which would be the default rate for all DG, or partial requirements, customers who submitted an interconnection application after June 1, 2015.[241] Under the new net metering rider, new DG customers would be compensated for excess energy at a Renewable Energy Credit ("REC") Rate which is a rate that reflects the current cost of utility-scale solar energy tied to the distribution system.[242]

Contrary to the Company's contention, RUCO does not believe TEP's new net metering proposal sends accurate price signals to new DG customers but is intended to increase fixed cost recovery.[243] RUCO submits that a balance between fixed-cost recovery and proper price signals must be reached.[244] While agreeing that the compensation method for DG needs reform, RUCO contends that TEP's proposal can be improved by creating more options for DG customers.[245] As a result, RUCO proposed four options for DG customers, including a "RPS Credit Option,"[246] none of which would include a mandatory or default rate, though some restrictions may apply.[247] The RPS is intended to be a DG customer option to and sits alongside the more traditional or current net metered rate and be in place during the interim period between the effective date of the order from Phase I hereof the completion of Phase II.[248] RUCO asserts that the RPS Credit Option is not dependent upon the Value of Solar docket.[249]

As originally proposed, RUCO's RPS Credit Option consisted of a "buy-all sell-all" credit-like structure which rate would be fixed and linked to REST targets[250] and operate conceptually like

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[240] Tr. at 921:3-20
[241] Ex. TEP-1 at 6.
[242] *Id.* at 7.
[243] Ex. RUCO-10 at 31 (Huber Rate Design Direct).
[244] *Id.*
[245] *Id.* at 32-33; also labled as RES Credit in RUCO's Direct Testimony.
[246] *Id.* at 33.
[247] *Id.* at 34.
[248] Tr. at 687-688; Tr. at 1473:13-15.
[249] Tr. at 1473:20-21.
[250] Ex. RUCO-10 at 41.

declining upfront incentives.[251] The credit would begin at a set rate, gradually decline at a fixed, predictable way over 20 years as more solar capacity comes online. Rates would be designated by "Capacity per Tranche" and "Price per Tranche."[252] The basis for each capacity tranche was formulated to create an average blended rate across all tranches of approximately 7.7 cents/kWh, conform to RUCO's long-term breakeven analysis, and be close to yearly REST compliance targets.[253] The proposed Price per Tranche decline rate figure of 7% was set to roughly equal historical system cost declines.[254] The proposed rate for the final tranche would be the Market Cost Comparable Conventional Generation ("MCCCG") rate plus any adder the Commission deems reasonable.[255] As a condition to participating in the RES Credit Option, customers must assign their RECs to the Company.[256] RUCO proposed that the credit rate begin at $0.11/kWh which is the most similar to the current rate design.[257]

Other intervenors, most notably Vote Solar and EFCA, have taken issue with RUCO's RES Credit Option and have proposed some modifications to it. According to Vote Solar, the genesis of RUCO's RES Credit Option is a proposal in RUCO's Exceptions to the Recommended Opinion and Order in the UNSE rate case (Decision No. 75697) which was denoted as the RPS Credit Option.[258] It is an alternative for DG customers and functions with retail net metering while maintaining all existing tariff options for such customers.[259]

Vote Solar points out that the most significant difference between the approved UNSE RPS Credit Option and RUCO's proposed RES Credit Option is that the latter is strictly a buy-all, sell-all agreement.[260] Vote Solar believes that RUCO's modifications to its RPS Credit Option in the UNSE case were significant improvements in that they allowed it to function alongside existing tariffs and

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[251] *Id.*
[252] *Id.* at 41-425.
[253] Ex. RUCO-11 at 9 (Huber Surrebuttal).
[254] *Id.* at 10.
[255] *Id.* at 10.
[256] Ex. RUCO-10 at 42.
[257] *Id.*at 43.
[258] Ex. Vote Solar-5 at 8 (Kobor Surrebuttal).
[259] *Id.* at 8-9.
[260] *Id.* at 9.

gave customers the choice of selecting the credit rate for all generation or just for exports.[261] Vote Solar is not opposed to the RPS Credit Option but believes limited improvements should be made including that all solar capacity, whether or not selecting the RPS Credit Option, would count against the tranches[262] and that RUCO's suggested tranches be redesigned.[263]

Vote Solar submits that, in the event the Commission considers the RES Credit Option in Phase I of this matter, it is important that it maintain a structure similar to that approved in the UNSE case, i.e., (1) offer it as an additional program to function together with existing residential and small commercial tariff options for NEM and non-NEM customers and (2) allow customers who select it to have the choice to apply the fixed credit to all production or only to exports.[264] Vote Solar also recommends that the Commission calibrate the tranches and rates to ensure gradualism and allow for consistent application of the outcome of the Value of DG docket.[265]

In part because of the Commission's decision in the UNS Electric rate case (Decision No. 75697 in Docket No. 15-0142) and to accommodate the concerns of solar roof top representatives, RUCO modified its RPS Credit Option to allow prospective solar customers the choice of whether they want the credit rate to apply to all of their production or just exports.[266] In addition, export only customers would fully count toward the capacity of a given tranche.[267] Lastly, RUCO submits that the RPS Credit Option structure is very flexible, capacity levels and credit rates can be adjusted on a going forward basis to accommodate new policy directions, technology and locational data, etc. and can be easily adapted to incorporate the outcome of the Value of Solar docket, if the Commission wishes to do so.[268]

Staff does not oppose the RPS Credit Option because it is just that . . . an option. Until the Commission decides what, if any, changes should be made to net metering the RPS Credit Option provides an additional option to existing net metering customers.

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[261] *Id.* at 10.
[262] Tr. at 2209:10-17.
[263] Ex. Vote Solar-5 at 11.
[264] *Id.* at 10.
[265] *Id.*
[266] RUCO-11 at 9 (Huber Surrebuttal).
[267] *Id.*
[268] *Id.* at 11-12.

11. Optional demand charge.

As part of its rate design changes, the Company proposed an optional three part rate plan for its residential customers. The proposal consisted of the basic service charge, plus the inclusion a two tier monthly demand charge.[269] The breakpoint for the two tier demand charge will be at 7 kW.[270] Billing demand will be based on the 1-hour maximum measured demand during the billing month.[271] The Delivery Service-Energy charges have a single tier and are reduced significantly from those in R-01 to reflect the fixed cost recovery being more properly recovered through the demand charges.[272] All other charges are identical to those in R-01.[273] For RES-D-TOU, the Basic Service, Demand, Delivery Services-Energy, and all other charges except Base Power are the same as those for RES-D. The Base Power Charges vary by time of use.[274]

According to Company witness Dukes, the three part rate will reward a customers for lowering their usage and changing their load profiles. Under a three-part rate, customers receive a price signal encouraging them to improve their load factor, which benefits the customer by reducing their electric bills and benefits all TEP customers as the system is used more efficiently.[275]

Staff supports a move to three part time of use rates for residential customers over the long term.[276] For this case, Staff is recommending that an optional Three Part-TOU rate be made available to both RES and SGS customers.[277] This optional rate may be attractive to customers that use energy efficiently and effectively.[278] Staff also recommends that all RES and SGS customer bills include the customer's monthly On-Peak and Off-Peak demands (although the demand values would not be used for billing unless the customer has chosen the optional demand rate). [279] The Company should also develop a customer information portal that would provide all customers with the ability to review

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[269] Ex. TEP-21 at 24. (Dukes Direct)
[270] *Id.*
[271] *Id.*
[272] *Id.*
[273] *Id.*
[274] *Id.*
[275] *Id.* at 26.
[276] Ex. S-10 at 9. (Solganick Direct)
[277] *Id.* at 14.
[278] *Id.*
[279] *Id.*

their demand and energy consumption and evaluate various option rate forms so that customers can make informed decisions about rates, energy efficiency and emerging technologies.[280]

The issues related to the Company's mandatory demand rates for new DG customers has been deferred to a Phase 2 hearing.[281]

V. CONCLUSION.

For the reasons stated herein, Staff supports the Settlement agreement as written. Staff recommends the adoption of the Agreement by the Commission without amendment. Staff's positions regarding cost of service, revenue allocation and rate design and reasonable and should be adopted.

RESPECTFULLY SUBMITTED this 31st day of October, 2016.

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[280] *Id.*

[281] August 22, 2016 procedural order at 2-3.

On this 31st day of October, 2016 the foregoing document was filed with Docket Control as a Staff's Closing Brief, and copies of the foregoing were mailed on behalf of the Utilities Division to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

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