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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE, Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

Arizona Corporation Commission
DOCKETED
OCT 31 2016
DOCKETED BY

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD 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

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CLOSING BRIEF

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing its Closing Brief in the above referenced matter.

INTRODUCTION

Tucson Electric Power's ("TEP" or the "Company") rate application, and the proposed Settlement Agreement ("Settlement") that is the main subject of this phase has raised the passions of all the parties involved. It is a compliment to the Commission's process that so many parties with such diverse interests could address and resolve so many different issues within such a short period of time. RUCO lauds the signatories for working so hard to fashion a proposal that they believe balances all of the competing interests.

The Settlement is in the public interest for numerous reasons which will be discussed in detail below. The Commission should approve the Settlement.

The Settlement, however, did not resolve all of the outstanding issues. The issues related to changes to net metering and rate design for new DG customers have been deferred to Phase 2 of the rate case. See Procedural Order of August 22, 2016 at 2-3. The other outstanding issues that remain in dispute include the Company's proposal to increase its Basic Service Charge 50% from its current rate and more narrowly, the Company's use of the minimum system method to allocate distribution system costs. RUCO also disagrees with the Company's proposals to modify the LFCR, and the ECA. RUCO further recommends an 80/20 sharing on the Company's long-term purchased power costs. There are several proposed tariffs that include TEP's Economic Development Rider and AECC's proposed Buy Through tariffs which RUCO is concerned. Finally, RUCO has proposed that the Commission approve its RPS Credit Option and conservative meter fee consistent with the Commission's recent Decision in the UNSE Electric case. See Decision No. 75697.

THE PROPOSED SETTLEMENT IS IN THE PUBLIC INTEREST

Among other things, the following bullet points highlight the benefits of the proposed Settlement:

- As proposed in its original Application, the Company sought a $109 million revenue increase.[1] The Settlement recommends an $81.5 million revenue increase. RUCO-5, Attachment A at 5. Of the $81.5 million proposed increase, $15.2 million is related to the non-fuel operating costs associated with the Company's 50.5 percent share of Springerville Generating Station

("SGS") Unit 1. Id. at 3-4. The Company originally requested this amount be passed through its PPFAC but it changed its request and sought inclusion of non-fuel operating costs in its base rates. Since these operating costs would be borne by ratepayers regardless of the rate case, the Settlements true revenue increase is approximately $66.3 million. Id. at 4.

- A permanent write down of the Net Book Value of the TEP headquarters by $5 million which results in a $5 million dollar reduction to Original Cost Rate Base. This will resolve the TEP headquarters issue that was an issue in the last rate case, and in this rate case, and going forward. Id. at 2.

- The inclusion of post-test year plant that was in service as of June 30, 2016 in the amount of $49.6 million, and post-test year renewable generation plant in the amount of $4.8 million. This is a reduction of $18.1 million[2] from what the Company requested in Rebuttal testimony. Id.

- The following changes to depreciation and amortization rates:

    - The rates for San Juan Generating Station will be adjusted to reflect a depreciable life of TEP's total investment, including the Balanced Draft project, at San Juan Unit 1 of six (6) years;

    - $90 million of excess distribution reserves will be transferred to San Juan Unit 1

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[1] For ease of reference, trial exhibits will be identified similar to their identification in the Transcript of Proceedings. The Transcript page number will identify references to the Transcript.

[2] See Company Rebuttal Schedule B-2, Page 2 of 5.

- A change to depreciation rates on TEP's distribution plant to offset the change in depreciation expense for the San Juan Unit. Id. at 3.

- Additional provisions include the following:
  - A six year historical average of outage expenses.
  - Exclusion of 2017 payroll expense of 2 percent related to non-classified employees.
  - A 50/50 sharing of short-term incentive compensation.
  - Rate case expense of $1 million normalized over four years, and
  - Removal of $1.1 million associated with litigation costs related to Alterna. Id.

- <u>Cost of Equity Capital</u> – The Company requested a 10.35% cost of equity and the parties agreed to 9.75% in the final settlement. RUCO-3 at 2.

The Settlement is in the public interest for every one of the above reasons. The Settlement is a fair and reasonable resolution which is beneficial to the Company's ratepayers while at the same time provides the Company a reasonable opportunity to earn its fair rate of return. For the above reasons, the Commission should approve the Settlement.

THE COMMISSION SHOULD APPROVE RUCO'S RECOMMENDED RPS CREDIT OPTION CONSISTENT WITH WHAT THE COMMISSION DID IN THE RECENT UNSE MATTER

The Commission should approve RUCO's RPS Credit option in Phase I of this proceeding because it provides an option for solar customers, it is a mechanism that provides certainty for customers choosing solar, and precedent for approving it has already been set in the UNS Electric rate case. The RPS Credit option proposed in this rate case is not meant as a replacement for net metering, but as an alternative to net metering. The RPS Credit option is an optional compensation method that sits on top of the Company's existing rate offerings and provides an alternative compensation rate, providing 20 years of certainty for customers' selecting it. RUCO-10 at 42. The RPS Credit option, in this case, is designed identically to the RPS Credit option approved in August in the UNS Electric rate case. The step downs are formulated based on the same historical system cost decreases and the starting compensation rate is .11 cents/kWh, which is close to the retail rate. Id. at 41-42. Structurally, the only difference being the use of TEP's REST compliance target, rather than UNS Electric's target. TEP needs 85 MW of additional distributed generation to become REST compliant. Id at 41.

In the August UNSE Open Meeting, some of the rooftop solar advocates made a number of unsuccessful arguments attempting to prevent the option from being approved. First, came the false claim that, aside from a chart, there was not "any" evidence showing how the RPS Credit option would work. UNSE Open Meeting Transcript Vol. II at 209[3]. Next, the argument that the tranches were sized too small. Id. at 210. Next, came the argument that a proper evaluation of the RPS Credit option didn't take place because it had changed over time. UNSE Open Meeting Transcript Vol. II at 227. Next came the cost to implement the RPS Credit option. UNSE Open Meeting Transcript Vol. III at 461. Next came communicating install capacity to let the public know the current tranche. Id. at 464. Each argument was shown to be meritless. For example, at the Open Meeting Commissioner Stump read excerpts from the underlying hearing demonstrating that there was, in fact, evidence on the record in support of the RPS Credit option. UNSE Open Meeting Transcript Vol. III at 460. Additionally, the only

[3] Attached as Exhibit A is a copy of the relevant excerpts from the August 11, 2016 UNSE Open Meeting

change made to the RPS Credit option in the rate case was a modification which RUCO agreed to in response to a request from a solar party. UNSE Open Meeting Transcript Vol. II at 234. It is unfortunate that individuals from the solar industry would use RUCO's approval of a solar requested modification to its RPS proposal as justification for not approving the option. Commissioner Stump expressed his disapproval of the solar industry's tactics when he opined;

> "Guys, I have to be honest with you. I think I could put out anything here and you would oppose it, quite frankly. That's the sense I am getting. Here we have a pro solar amendment that is innovative. You claim to be in favor of solar customers. It is simply another choice, a benign choice, allowing solar customers to have yet another choice. You claim to be pro choice. I, frankly, get the feeling that anything I put out here you are going to oppose and throw the kitchen sink. And once the kitchen sink is thrown out there, I will have another household appliance thrown at me, so..."
>
> UNSE Open Meeting Transcript Vol. III at 469-70.

Unfortunately, these types of strategies were not just confined to the UNS Electric rate case. These same types of strategies are being employed here in the TEP rate case. EFCA claims that its primary interest in this rate case is "to maintain and encourage consumer choice and fair rate setting practices, particularly as it applies to the Company's solar customers and those customers who hope to power their homes and businesses with solar in the future." EFCA-9 at 5. This is difficult to believe when EFCA has gone to such extremes as to attempt to stop a "pro solar amendment" from being approved. In this case, EFCA was unsuccessful in their attempt to have parts of Mr. Huber's testimony, those relating to the RPS Credit option and the meter charge, stricken from the record, even though both of these topics were addressed in Phase I of the UNS Electric rate case by the Commission. See EFCA's Motion to Strike Testimony of Lon Huber.

In this case, Vote Solar did provide testimony with proposed modifications to RUCO's Credit option. Vote Solar-5 at 10-12. Vote Solar's expert, Ms. Kobor, sought to have RUCO's proposed tranches modified to align with historical yearly install rates rather than solar installed capacity. Id. She did this because she was concerned that solar customers would move through RUCO's proposed tranches too quickly. Id. As it turns out, Ms. Kobor's concern was misplaced. Ms. Kobor was confused - her confusion centered on what capacity would be included in the RPS Credit option. Ms. Kobor was mistakenly counting all new rooftop DG generation as capacity towards reaching each tranche level. RUCO's proposal has been and continues to be that only new DG generation that has exchanged RECs, counts towards the tranches – not all of the new DG generation (rec and non-rec alike). This confusion was shared by EFCA as well. UNSE Open Meeting Vol. II at 210. Under this mistaken understanding, Ms. Kobor would be correct that each of the tranche levels will be reached faster if the proposal included all new DG capacity. However, that is not, nor ever was RUCO's proposal. RUCO's RPS proposal was always tied to the RES standard with the goal being the achievement of the yearly RES standards through the exchange of RECs.

Admittedly, RUCO thought the title, "RPS Credit Option" just by itself, was sufficient, but perhaps RUCO has not been overtly clear in explaining it elsewhere and relied on spreadsheets to heavily. Nonetheless, at the hearing it was spelled out and Ms. Kobor admitted she now understood the distinction. Transcript at 2211. However, rather than acknowledge the confusion as the source of her misplaced recommendation, Ms. Kobor said she felt that Mr. Huber had "moved the ball" suggesting RUCO had a deceitful motive. Transcript at 2110. This could not be further from the truth – Mr. Huber's motives were and remain genuine which could not be more apparent than from the nature of the pro-solar RPS Credit proposal itself.

The confusion, exhibited by some from the solar industry, seems to be more self-inflicted than anything. In the UNS Electric rate case, rather than spend time asking questions about the RPS Credit option, the solar stakeholders in that case spent very little time addressing it. Even after letters were submitted to that docket, by Commissioners Stump and Burns, asking for all parties to provide more comments specifically on the RPS Credit option. UNSE Open Meeting Transcript Vol. III at 467. Fast forward to this rate case, now that the parties realize the Commissioners meant business, cross-examination in the hearing easily identified that only capacity where RECs are exchanged would be included in the RPS Credit option. Transcript at 1601-1603.

RUCO believes that the certainty the RPS Credit option provides, for customers choosing to install solar, is further reason to adopt the RPS Credit option. With the Value of Solar docket still not complete, this option allows customers to choose to install solar under terms that provides certainty now and that is not reliant on the Value of Solar docket. Additionally, the value proposition of the option is rich. Tucson solar installer, Kevin Koch, validated this assertion when he said concerning the RPS Credit option, "[i]t makes sense as a very secure choice for consumers to make. And as a secure choice, I see it as making sense to have a little bit less favorable economics associated with it." Transcript at 1767. The RPS Credit option as RUCO has shown is a secure option.

RUCO believes the precedent and desire of the Commissioners, to act on the RPS Credit in the UNS Electric rate case, to be a very compelling reason to propose it in Phase I of this rate case. This is why RUCO is proposing both the RPS Credit option and the meter fee for DG customers. Some from the solar industry apparently disagree with this assessment. In cross-examination, Vote Solar's witness Ms. Kobor was asked about a statement made in her testimony where she said that "[g]iven the procedural realities, there is no compelling reason to consider the RPS credit option in Phase 1." Transcript at 2206. She was asked, "[d]o you think that the fact that the Commission unanimously approved the RPS credit option in the UNS rate case is a compelling reason?" Id. Ms. Kobor answered, "I do not." Id. When pressed further she agreed that it was "at least a reason." Id. RUCO will not be so daring as to go against the obvious wishes of the Commission.

THE COMMISSION SHOULD APPROVE RUCO'S RECOMMENDED $6 METER FEE CONSISTENT WITH WHAT THE COMMISSION DID IN THE RECENT UNSE MATTER

The issue of the meter fee was addressed and decided by the Commission in the recent UNSE case. Given the relatively short time since the Commission decided that case (October 18, 2016) there is no reason why the Commission should not decide this identical issue in Phase One of this case - to do otherwise would be inconsistent. Nonetheless, the solar industry (EFCA and Vote Solar) have made the argument that the Commission should disregard the UNSE decision and consider an additional meter fee in Phase 2. Vote Solar - 5 at 13, EFCA-11 at 3. RUCO believes punting the decision until Phase 2 would be inappropriate, inconsistent, and has proposed a conservative meter fee consistent with the Commission's actions in the recent UNSE rate case. Decision No. 75697 at 118. RUCO's proposed meter fee is $6 per month based on the Company's marginal cost study from which RUCO estimated the administrative costs and the monthly hardware related meter costs per customer. RUCO-11 at 13. RUCO's estimate was purposely designed to be conservative because it does not take into account the incremental additional cost of an upgraded bi directional meter unique to solar customers. Id. TEP also recommends a meter charge for new net metering customers of $9.13 based on its marginal cost. TEP-32 at 24.

The solar industry is critical of RUCO and TEP's use of marginal cost. Both EFCA and Vote Solar argue that marginal cost is the wrong measure – the proper measure would be the embedded costs since the purpose of marginal cost pricing is to send a price signal to ratepayers to inform their decisions. EFCA-11 at 4. In support of their argument, they refer back to the Commission's Decision in UNSE where the Commission set the meter charge at $1.58 as the additional fixed cost. EFCA-11 at 5. Decision No. 75697 at 118. Based on the embedded cost in this case, EFCA calculated the meter cost to be $1.68 for residential customers and Vote Solar calculated the additional meter cost at $0.32 per month for solar customers. Vote Solar - 5 at 13-14, EFCA-11 at 5.

However, like every issue in every case, the matter must be placed in context and considered in light of the facts and circumstances of that particular case. In the UNSE case, the discussion came about as the result of a last minute proposed amendment made by the UNSE in an open meeting. UNSE did not suggest nor recommend in its amendment that the Commission approve an amount which recovered all of the embedded costs. In fact the Company even acknowledged that ascertaining all of those costs would be difficult and the net metering bills were complicated. See attached excerpt of the Commission's Open Meeting of 08/11/2016 at 523 (Exhibit B). Rather, the Company was only looking to establish a placeholder – a proxy of the representative number of the production meter cost "...to get us moving in the right direction." Id. Even Vote Solar recognized the $1.58 approved amount in UNSE for what it was, a partial representation of the capital costs of the production meter with an investigation necessary to determine the additional meter costs in Phase 2. Id. at 524. Vote Solar stated in that case that it could "accept" the proposed amendment to include that cost. Id. at 524.

This issue was hardly vetted in UNSE – it was only given cursory attention because it was introduced so late in the proceeding. But clearly the idea in UNSE was to set up a conservative proxy to move us towards a meter fee that is representative – representative of what the costs are for new DG customers with new meters. The best data to use for determining what new meter costs will be for new DG customers is data determined in a marginal cost study. TEP-32 at 24. In this case we have the benefit of hindsight, we have a marginal cost study, and we know the actual hard costs (administrative, meter reading, hardware) of the second meter from the Company's marginal cost of service study. Transcript at 1539, 1542 – 1545, TEP-30, CAJ-1. Moreover, the marginal cost study used in support of both RUCO and TEP's recommendation only includes the costs associated with the production meter, and not the more expensive bi-directional meter which further deflates both RUCO and TEPs cost recommendations. TEP-32 at 24. But to highlight the conservative nature of both TEP and RUCO's proposed meter cost proposals, the total basic installed cost only of the AMRS meter is $71 and the total basic installed cost only of the bi-directional meter is $216.00. Vote Solar 2. RUCO's conservative $6 monthly proposal attributes $3.10 for the actual cost of the meter and $2.90 for the administrative cost. Transcript at 1545. RUCO's proposal is only an interim recommendation until the Phase 2 determination so there is no possibility that the Company will over-collect the meter costs. Quite the contrary, each proposal will at best only be a start towards collecting the meter costs associated with solar systems. RUCO believes that the Commission should consider a fair proxy under the facts and circumstances of this case and not be hamstrung as the solar industry seems to be advocating by the facts of the UNSE case. Again, in this phase the purpose is not to calculate the total embedded costs but to determine a proxy that moves the Company forward in starting to recover meter costs.

In reality, all the numbers for the meter fees being proposed in this case are outliers. Nobody can legitimately argue that the total marginal and/or embedded costs of the meters are reflected in the $0.32 per month recommendation of Vote Soar or even the $6 RUCO recommendation for that matter. The Commission should approve RUCO's $6 proposed meter fee as it is a fair and reasonable proxy towards collecting the meter fees associated with solar.

THE COMMISSION SHOULD APPROVE RUCO'S RECOMMENDED BASIC SERVICE CHARGE

Throughout this case, the Company has emphasized the need to move towards cost of service ratemaking. The Company's original proposal to address its concern was to increase the basic service charge from the current rate of $10 to $20 – a 100% increase. TEP-30 at 43. The Company changed its proposal in its rebuttal case to more closely align with the Commission's recent Decision in the UNSE case (Decision No. 75697). TEP-32 at 3. The Company's current position reduces the current basic service charge from its recommended $20 per month proposal to $15 per month provided the Commission approves the Company's proposal to remove two tiers from its current volumetric rate design resulting in a total of two tiers compared to the current four tier volumetric rate design. Id. Additionally, the Company is recommending a $3 per month reduction to the standard residential rate and a $5 per month reduction for its standard SGS customers for the optional TOU and three part rates being proposed for these classes. Id. It is unclear what the Company's position would be if the Commission does not approve the Company's proposal to reduce its volumetric rate design to two tiers. Transcript at 2597.

RUCO proposes to increase the fixed charge to $13 from the current monthly rate of $10. In order to incentivize the adoption of the TOU rate, RUCO, similar in concept to what the Commission approved in the recent UNSE decision, also proposes to reduce the charge on TOU based customers to $10. RUCO-11 at 4, See Decision No.75697 at 66. RUCO also proposes a volumetric rate design with three tiers, eliminating the Company's top tier (>3,500kWh). RUCO-10 at 24.

While there has been a lot of evidence placed in the record on this subject, RUCO and the Company's basic service charge proposals are really not that far apart. RUCO sees this as a policy call for the Commission but recommends the Commission adopt RUCO's proposal as it has better support in the record, is based on the traditional cost of service methodology used by the Commission and recognized in virtually every state, and is more fair to the ratepayer. Finally, RUCO's proposal is not conditioned on the Commission approving RUCO's recommended number of tiers in its volumetric rate design.

A much wider gap exists between the methodologies used to support RUCO and the Company's recommendations. The Company's proposal is based on the minimum system method which is controversial, not cost based and relies on a completely hypothetical distribution system sized to serve no customers. Sweep-1 at 8. The hypothetical system is patterned off of a system with little or no load carrying capabilities. Id. The minimum system method assigns all of the costs associated with a theoretical minimum system to the customer classification. The irony in its use by the Company is that it is counter to actual cost of service, the very objective the Company strives to achieve in its proposals to correct its perceived fixed cost problem.

What it does accomplish, however, is placing more costs in the basic service charge than are actually incurred by the customer. This should be expected given the Company's desire to place more costs in the fixed component. It should be noted that no state, at least in the record of this case, has adopted the minimum distribution system methodology and perhaps the most renowned authority on utility regulation, Professor James Bonbright has rejected it as an appropriate methodology. In his treatise, *Principles of Public Utility Rates*, Second Edition, Professor Bonbright notes:

> But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reason stated previously, to which cost function does it then belong? *The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should*

> *be recognized as a strictly unallocable portion of total costs.* And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully-distributed costs analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole." They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories. (Emphasis Added)

Bonbright, James C., *Principles of Public Utility Rates*, Second Edition, Arlington, Virginia, Public Utilities Reports, Inc. (1988). Print at 492, Transcript at 793-794.

The point of this passage hardly needs an explanation, however, when crossed on it during the hearing, the Company's witness Dr. Overcast, testified that if Professor Bonbright were alive today he would accept the minimum system cost approach and if one read Bonbright carefully ".... You end up with a definition of customer costs that's only met by the minimum system method." Transcript at 794-795. Dr. Overcast has a client to represent and a position to support which perhaps explains his testimony but it is clearly a stretch. Distribution, energy and customer costs today are still distribution, energy and customer costs like they were 50 years ago. How the Commission decides to allocate them is a policy call, but the nature of the costs are still the same. The "empirical evidence" that Dr. Overcast alludes to but does not explain to support his supposition does not impact the nature of the costs. Dr. Overcast's testimony is a stretch at best, is misplaced, and should be rejected. It is simply a transparent attempt to support, an unsupportable methodology which has been rejected by nearly almost every state, leading regulatory academics, and is designed to increase the Company's basic service charge.

RUCO supports the basic customer method which is consistent with Professor Bonbright's common sense recommendation that costs should be classified as customer related. Sweep-1 at 9. The customer related costs generally include those costs associated with meters, billing and customer service. Id. The basic customer method only allocates customer specific costs based on the actual number of customers and excludes costs related to the overall demand on the system, such as distribution poles and wires. RUCO-10 at 15, 17. These demand costs are common to large groups of customers, not individuals, and should therefore not be recovered on an individual basis. Id.

For instance, a customer who uses 500 kWh a month should not pay the same for utility poles as the same customer who uses 5000 kWh per month. Yet under the minimum system distribution approach both customers would pay the same. TEP-30 see Schedule CAJ-1, Schedule-1. This is unfair to the ratepayer and sends the wrong price signals to TEP's customers. RUCO-10 at 19. The customer with the smaller usage should pay his percentage share since that accounts for the benefit received. Id. The basic customer method does not include common costs, but only costs which are customer specific. The Commission should approve the basic customer method.

Under the basic customer method, the cost elements for individual customers are lower than the Company's revised proposal of $15. RUCO calculates the marginal cost to serve an individual customer under the basic customer method to be $10.34 per month. RUCO-10 at 18. By RUCO's calculation, the basic customer charge is very close to the current $10 basic service charge and almost 50% less than the Company's calculation of $15 under the minimum system method.

The Company quantified the fixed cost per residential customer in its cost of service study at $93.61 per month. TEP-30 at 44. The Company's $15 proposal is approximately 16% of the total $93.61. RUCO is very concerned that the Company will continue to advocate towards recovery of the entire $93.61 in its basic service charge since the Company seems to be advocating for the inclusion of all fixed costs in the fixed charge. TEP -30 at 43. Given TEP's position, there will be no resolution of this issue for the foreseeable future. The minimum system approach is not based on actual customer counts or actual costs, nor does it appear to have sidewalls or limits – a perfect methodology to achieve the Company's objective – the recovery of the $93.61 per person in monthly fixed costs. Once the minimum system method is approved, what or who is to stop the Company from including transmission and generation costs in the minimum system method?

This case squares the issue of just how far the Commission believes fixed costs should be recovered through higher fixed charges. There is no fundamental reason why fixed costs must be recovered through fixed prices. RUCO-10 at 4. According to Bonbright, "Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of a complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation, but subject to the market forces of competition."[4] Thus, if rates are intended to emulate prices charged by competitive enterprises, there is no rationale for regulated utilities to implement fixed charges instead of other pricing options. Bonbright goes on to say that "regulation should allow a fair rate of return, but not guarantee or protect a regulatee against mismanagement or adverse business conditions."[5] By proposing to recover more its costs through fixed charges the Company is in essence attempting to insulate itself, in part, from adverse business conditions. Id. at 10

The notion of recovering more of its fixed costs through fixed charges is not unique to TEP. There seems to be a movement in the country by utilities to change the practice of keeping the basic service charge low. A recent study by Synapse analyzed 51 such utility proposals decided between September 2014 and November 2015 and found that 41% of these

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[4] Bonbright, James Cummings, *Principles of Public Utility Rates*, Edition 1, (1961). Print at page 141
[5] *Ibid.* page 382

proposals were rejected, while 33% were scaled back. The average approved fixed charge for these decisions is $11.87.[6] RUCO-10 at 11.

Likewise, in the subject record, it was shown that many if not most state PUCs do not support methodologies like the minimum system method designed to increase if not inflate fixed charge recovery. Mr. Huber cited to Utah, Washington and Maryland where the PUCs have adopted the use of the basic customer method. RUCO-11 at 14. Mr. Baatz references PUCs in Michigan, Minnesota, Illinois who refused to move away from the "long-accepted principle that basic charges should reflect only "direct customer costs" such as meter reading and billing." Sweep-2 at 15. Dr. Overcast, rejects these cases, and when asked could cite to only one state, Connecticut which he was confident had adopted the minimum system method in 1982[7]. Transcript at 726. Mr. Huber, however, subsequently refuted Dr. Overcast and testified that Connecticut has rejected the use of the minimum system method. Transcript at 1466. Mr. Huber even cites to the Connecticut Statute (CT General Statute Section 16-243bb) which was passed into law in 2015. Transcript at 1649 – see Exhibit C. It appears that in Connecticut, legislation was necessary to require the basic service method to "stop runaway fixed charges." See Exhibit C.

The Commission should once and for all reject the Company's attempt to increase fixed charges through the minimum system method. There are other ways to address fixed costs which send appropriate price signals and are fair to the ratepayers. The approval of the minimum system method would put the Commission on a slippery slope moving forward and

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Ibid. page 382

Whited, M., Woolf, T., Daniel, J. (2016). Caught in a Fix: The Problem with Fixed Charges for Electricity. p 43.

[7] Dr. Overcast was less confident and could not cite to the cases in Oklahoma, Kansas, Missouri and Arkansas. Transcript at 726.

validate the need for an unknown number of future increases in the basic service charge with no end in sight.

TEP'S VOLUMETRIC RATE DESIGN SHOULD CONSIST OF THREE TIERS

The Company currently implements an inclining block rate for standard residential customers that includes four usage tiers.[8] RUCO-10 at 23. The Company proposes to eliminate the third and fourth tiers of the residential rate class. This would leave only two usage tiers: 0-500 kWh usage and usage above 500 kWh. RUCO believes it is appropriate to eliminate the current top usage tier (>3,500 kWh). However, for the following reasons RUCO does not support the elimination of the third usage tier (>1,000 kWh). Id. at 23-24.

The elimination of the top tier is likely to have minimal impact on the vast majority of residential customers. Based on RUCO's analysis of customer billing data provided by the Company, it appears that only a small number of customer bills and revenues collected (approximately 1% each) are associated with the top tier.[9] Id.

Unlike the top tier, a significant number of customer bills and revenues collected are collected through the third tier.[10] The elimination of the third tier will have significant impacts on a large number of customers. Id. at 24.

One of the more significant impacts relates to the bill impacts for low use customers. Another impact relates to the price signal for energy conservation. First, by eliminating the third tier, a greater share of the utility's costs will necessarily be recovered through the first and

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[8] Tier 1 ranges from 0-500 kWh
[9] Calculated from data presented in Schedule H-5 of the Company's testimony.
[10] Based on data presented in Schedule from 0-500 kWh
[10] Calculated from data presented H-5 of the Company's. Transcript at 726.
[10] Tier 1 ranges from 0-500 kWh, RUCO estimates that approximately 40% of customer bills and 34% of revenue collected are presently associated with tier 3. [10] Dr. Overcast was less confident and could not cite to the cases in Oklahoma, Kansas, Missouri and Arkansas
[10] Calculated from data presented in Schedule H-5 of the Company's testimony.
[10] Based on data presented in Schedule H-5 of the Company's testimony

second tiers. Id. This means that the rate increase proposed for the first and second tier customers will be significantly higher than with a third tier. RUCO's concern is that lower usage customers, who also tend to have less income and less discretion over their energy consumption, will likely experience significant bill and rate increases. RUCO estimates that the proposed rate increase for customers in the first two usage tiers will be 5% and 18% respectively in the summer. Id. at 25. Concentrating bill increases on lower usage customers is a regressive policy that should be avoided. Id.

Second, by eliminating the third tier, higher usage customers will actually experience a decrease in the marginal price per kWh consumed. Eliminating the third tier will reduce the price signal to save energy for the group of customers with the highest consumption. Id. at 26. RUCO estimates that approximately 41% of customers who are higher-end users will experience a rate decrease in the summer. Id. These high-use customers are likely to have the greatest discretion over their energy usage which makes the Company's proposal counter-intuitive. Why would the Commission want to approve a rate design which gives the highest users a reduction and the lowest users an increase?

The Commission should not approve a plan which sends perverse price signals to ratepayers. The Commission should approve RUCO's three-tier proposal.

THE COMMISSION SHOULD REJECT THE COMPANY'S PROPOSED MODIFICATIONS TO THE LFCR AND ECA

LFCR - the Company has proposed the following modifications to the LFCR.

- The Company has proposed that it be allowed to recover 100 percent of lost fixed costs attributable to generation (currently zero) and to be allowed to recover 100 percent of demand revenues (currently 50 percent).
- The Company wishes to increase the cap from 1 percent to 2 percent of test year revenues.

- The Company is also proposing to simplify the percentage-based LFCR Adjustment to be a single rate applied to customers' bills, rather than split the adjustment into two separate rates for Energy Efficiency ("EE") and Distributed Generation ("DG"). RUCO-4 at 36.

For the following reasons the Commission should reject TEP's proposed modifications to the LFCR. The Company's proposal to include generation costs in the LFCR is not new. Including generation costs in the LFCR has been proposed in the past, but never adopted by the Commission. In this case, RUCO believes that the Company should not be allowed to include generation costs in the LFCR. The Company's purchased power program has a significant amount of flexibility, which allows it to adjust its purchases to match its short-term needs, and as Staff's witness, Howard Solganick points out, purchased power is fungible. S-10 at 54. Purchased power is not affected if energy is delivered to a new or existing customer or sold off system. Id. Therefore, the Company has many opportunities to adjust its energy supply. Id. The impact of the Company's proposal would more than double the effect of the LFCR. Id.

Mr. Solganick further points out that the Company's proposed Economic Development Rate combined with the proposal to include the generation in the LFCR could have significant unintended consequences. Id. at 55. Specifically, the Company could bill existing customers for the generation costs within the LFCR mechanism, redirect the generation (energy and capacity) to a new customer attracted by the proposed economic development rates and effectively double collect on that load. Id. at 55.

The Commission should further reject the proposal to increase from 50 to 100 percent the distribution demand component in the LFCR mechanism. Distribution costs are not as fungible and some distribution assets cannot serve customers within the short term. A reduction in per sales customers may result in a shortfall in revenues to cover distribution fixed costs. Id. Also, the LFCR is designed to collect that portion of distributed costs recovered on a volumetric basis. Id. Some of the Company's rate schedules collect distribution costs through demand charges which will remain constant or change slower than a straight volumetric rate. Id. Therefore, the Commission should not include in the LFCR 100 percent of the distribution demand component.

Increasing the LFCR cap is not necessary if the Commission does not approve the changes to the LFCR. Id. at 56. Finally, applying a single rate to the customer's bill rather than splitting the adjustment into two separate rates for EE and DG eliminates transparency which is clearly contrary to the public interest. Customers should be able to look at their bills and see what it is they are being billed for.

ECA - the Company proposes to modify the ECA by: 1) increasing the cap on annual recovery through the ECA from .25 percent to .50 percent of prior test year revenues to help smooth the rate impacts of compliance with new environmental regulations and 2) converting the cap to a percentage based cap, which will allow for more equitable recovery from all classes. RUCO-4 at 38. The Company has not shown that it has been harmed by the under collection of revenues. Further, any increase in the percentage cap exposes ratepayers to more risk, which has not been compensated by a reduction in the Company's return on equity. RUCO recommends that the current ECA not be modified. Id.

THE COMMISSION SHOULD MODIFY THE RATE TREATMENT OF NON-JURISDICTIONAL SALES ABOVE THE AMOUNT IMPUTED IN RATES SO THAT THE PROFITS ARE PARTIALLY REDISTRIBUTED BACK TO RATEPAYERS

It is inequitable for the Company to exclusively profit off the sales of generator output that is supported by retail customers. RUCO-9 at 6. There are long overdue proposals by both Freeport Minerals/AECC and Noble ("AECC") and RUCO to change the current paradigm of allowing the utility to keep all of the profits associated with power sales. Transcript at 978, RUCO-9 at 6-8. As AECC's witness, Kevin Higgens, so eloquently put it, all utilities would prefer to have all of the risk of fluctuation in fuel and purchased power costs placed on the ratepayers. Transcript at 979.

Under the current PPFAC, TEP passes through 100% of changes in base fuel and purchased costs to customers in between rate cases. AECC-6 at 39. Mr. Higgen's testified persuasively that a 100% pass-through seriously reduces a utility's incentive to manage its fuel and purchased power costs as well as it would be managed if it remained exposed to the energy cost risk. Id.

These energy costs are not outside the Company's control. Id. at 40. Utilities need to manage their dispatch on an hourly basis which requires a sophisticated approach to managing utility owned resources. Id. The magnitude of TEP's short and long term fuel purchases is staggering – it is essential that TEP have the proper incentives for these transaction to assure that ratepayers are not paying more than they should. Id.

Aligning the interest of the ratepayer and the shareholder is a basic tenant of regulation. There is no reason why the Commission should allow the miss-alignment here to continue. AECC is recommending a 70/30 sharing provision. Id. at 66. AECC appears to be patterning its recommendation after the decision in the state of Washington. The Washington PUC approved the continuation of the 70/30 sharing provision as it was necessary to align the interests of customers and the utility in the management of the utility's fuel and purchased power costs. AECC-10 at 44.

In its testimony in support of the settlement RUCO recommended an 80/20 sharing provision of profits from long term off system sales. RUCO would support the AECC proposal if the Commission were inclined to approve it. If the Commission does not approve the AECC proposal with respect to the PPFAC then he Commission should support the RUCO proposal because the energy and capacity to support the contracts are already being paid for in retail rates. As stated above, it is inequitable for the Company to exclusively profit off the long-term sales of generator output that is supported by retail customers. The Company should still have an incentive to make these sales, however, or else they just wouldn't bother and both the utility and ratepayers would be worse off. Thus, RUCO proposed that 80% of the profits from these sales be passed back to retail ratepayers and 20% be retained by the Company as an incentive to keep making off system sales when the opportunity arises

THE COMMISSION SHOULD NOT APPROVE TEP'S PROPOSED ALTERNATIVE GENERATION SERVICE AND AECC'S BUY THROUGH PROPOSALS

There is no need for RUCO to argue the finer points of these proposals in this case. RUCO's does not take issue with the purpose of these proposals. RUCO's position, however, is to not oppose these programs provided they hold the residential customer class harmless. One thing that is clear from the evidence in this case – it is unclear that these proposals will hold the residential class harmless.

Rarely in RUCO's experience has a Company proposed a rate and not supported it. Yet, that is exactly what has happened with the Company's proposed Alternative Generation Service Experimental Rider. TEP-30 at 61. Granted, TEP had to propose it as a term of the Fortis settlement, nonetheless, there is no question that TEP is concerned about its impact.

TEP's witness, Mr. Jones notes that the Experimental rider allows certain large customers to "cherry pick" the cheap power which will "ultimately result in costs being shifted to the remaining customers." TEP-30 at 61-62.

Mr. Jones, among others, expressed similar concerns with AECC's Buy Through proposals. While innovative, Mr. Jones notes the Buy-Through Rider 14 still results in costs associated with providing the buy through option to a select few of customers coming out of the Company's total revenue requirement and thereby being paid for by the remaining customers. TEP-32 at 80.

Mr. Solganick also expressed concerns with the Buy-Through proposals. Mr. Solganick did not feel comfortable with it and could envision scenarios where the residential and other non-participant classes could be affected by the program. Transcript at 2435-2436.

In sum, at this point RUCO opposes both TEP's proposed Experimental Rider and AECC's proposed Buy-Through proposals as it is not clear that the residential ratepayer will be held harmless under these programs.

CONCLUSION

For the above reasons, the Commission should approve RUCO's recommendations.

RESPECTFULLY SUBMITTED this 31st day of October, 2016.

Daniel W. Pozefsky
Chief Counsel

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By Cheryl Fraulob
Cheryl Fraulob

EXHIBIT A

today they are asking you to impose mandatory demand charges on DG customers just, boom, right now.

You know, I will note just on Monday you had the decision, the SIB case. And that was certainly hailed by many on the Commission and those that were advocates for it as a nod to rate gradualism. And no matter what you feel about the outcome of that case, TASC certainly agrees with the idea of rate gradualism.

So what does that mean in this case? And we would submit that gradualism, you know, that RUCO's proposal that Director Tenney just spoke about is not an example of gradualism. In fact, it has these stepdowns which sort of cloak it in the idea of gradualism because it is stepping down over time and somehow that's gradual. But I think what the Commission needs to know is there was literally not a single proposal in the rate case that got less evidence submitted about it than this provision, than this proposal.

And so, you know, it was included. There was a chart that had a stepdown. But at no time did RUCO introduce any evidence about, you know, when the stepdown should occur -- not when, but what the rationale is for the stepdowns and for the size of the stepdowns and for the starting prices and the middle prices and ending price. And had they attempted to introduce any evidence about that and provide any rationale for it, you know, we would have, in turn, provided evidence that would have shown, for example, that when you look at their stepdowns, if you look at the historic adoption rate of solar, you would run through four or five of those stepdowns in a year. That's not very gradual. And so that's the kind of stuff that needs to get hashed out.

And I, and I am not even saying that necessarily TASC is eventually opposed to something like that. But certainly in this context, when there has been no evidence of it to support the stepdowns, the amounts or anything like that, I just don't think it is ready for consideration and should be, I think, maybe more in keeping with what Commissioner Tobin's amendment says, let's study it along with all the other stuff in phase two. So I would encourage the Commission that I believe it is premature to go down that path today.

And I guess I will comment, and I will comment more later, I was going to say more, but on Commissioner Stump's second amendment. I think it includes a lot of conclusory statements that are yet to be decided that, really, the purpose of the phase two would be to investigate some of those concepts.

I do agree and TASC does agree with the

happens over time. But that $2 million is felt today by residential ratepayers. There is no denying that fact. So we can get into how that gets digested and what happens down the road, but it is simply a fact. And it has been in the record when we talked about the LFCR. And I will get to Mr. Rich's comments later today on what has been in the record and what hasn't. But I just want to make sure it is clear that that is, those are real costs that are not being lost, they are being shifted to nonparticipating ratepayers today.

CHMN. LITTLE: Thank you, Mr. Huber.

Okay. Commissioner Stump, you have a question.

COM. STUMP: Yeah. Thanks. Briefly, Mr. Chairman, more of a clarifying question.

Mr. Rich, you have stressed the need to expand choice for DG customers, greater certainty for the industry, principles both of which I agree with. So I offered an amendment in which they can have an optional rate now, which can provide a modicum of certainty to future DG adopters as well as the solar industry, and yet you are opposed to it.

MR. RICH: Yeah, Chairman, Commissioner Stump. I think the key is that that proposal, that, the proposal that you have made is an option, while we appreciate options, and I don't mean this in a pejorative, but it essentially picks random numbers for the stepdown. And those were not vetted and they don't, they don't make sense with anything. They are not related to the cost declines.

For example, the first stepdown, if you look at the average system size in their territory, which is 9 kilowatts, I believe that first stepdown would happen after the installation of 86 rooftop solar systems. Why? Why would it happen after 86? What relationship does that have to the utility's costs? What relationship does that have to the decline in costs in the installation of solar perhaps? And those are things that we can look at, and we can look at those in phase two and talk about. If that's the way the Commission wants to go, they can then have evidence that they can look at and say, well, what is the number that would relate to something that would have a relationship to a cost decline or to some benefit or something like that.

And so options are great, but, you know, I think they need to be right. They need to make sense. And, frankly, from our standpoint this needs to be vetted more before it can make sense.

COM. STUMP: But you would say, regardless of those concerns, this would provide more choice to DG customers presumably?

MR. RICH: I think that's a logical truism. It would provide more choice. It is another option. But we just don't feel it has been vetted or it is the appropriate option at this time.

COM. STUMP: Mr. Chairman, without getting into the weeds too much, Mr. Huber looks like he is chomping at the bit.

CHMN. LITTLE: I would agree.

And just also remind the parties that there are a couple amendments out there where we are going to discuss this probably in much more detail. So in the interest of time, if you can just make sure that these are clarifying comments and not arguments.

COM. STUMP: Sure.

MR. HUBER: Chairman, Commissioners, to clarify, when a party does not ask another party questions and get, you know, their answers, it doesn't mean that there is nothing on the record and that you can't move forward with something. Mr. Rich decided not to ask a few questions. Other parties did, including Vote Solar. Vote Solar asked specific questions about how the declines are set up, the justification for all those numbers that Mr. Rich reads. It is actually based on the REST implementation plan compliance. So that's how those were there. But just because he didn't ask me the questions doesn't mean that we can't, we don't have enough information on the record to move forward.

And there is many more, but I will have that one clarification for now.

CHMN. LITTLE: Okay. Thank you very much. Appreciate it.

Okay. Seeing no one else on the board, if you will pass that microphone over to the gentleman on your right, Mr. Rich.

Good morning.

MR. HIATT: Good morning, Chairman Little, Commissioners. My name is Michael Hiatt, and I represent Vote Solar in this matter.

What I was planning to cover has already been covered so I will try to be brief and not duplicate what has already been covered this morning.

In this rate case UNSE proposes two drastic rate design measures for new solar customers, either of which alone would be a significant rate design change. First, they propose to require new solar customers, and only new solar customers, to pay mandatory demand charges. Second, they propose to eliminate net metering by reducing the compensation that solar customers receive for the energy they generate and export to the grid by nearly half.

to only new solar customers.

Moving on to the net metering issues, it appears that there is generally broad agreement in this case that it makes sense to wait to decide net metering issues until phase two. But as we have just heard, RUCO and Stump Amendment 1 proposed to implement an optional net metering alternative that would go into effect prior to phase two.

This RPS bill credit option has some strengths, in Vote Solar's opinion, and some significant flaws. But Vote Solar agrees with TASC, it would be premature to implement the program at this time without further study for many of the reasons that Mr. Rich has already noted.

And I would just also additionally note that, under a stepdown methodology such as this, it would be a significant policy decision by this Commission on how to move away from net metering, at what pace do you do so. And the details of those policy decisions matter, the details of the proposal matter. And it is, frankly, unclear and ambiguous based on what has been filed in this case so far and based on the text of the proposed amendment, exactly what the policy implications of this RPS bill credit would be. Such an important policy decision should be made in a transparent and clear manner and should be subject to thorough vetting and discussion. And Vote Solar would look forward to further reviewing that option in phase two of this rate case along the lines of Commissioner Tobin's Amendment 1, which would direct the parties to address the RPS bill credit option and an additional option in phase two.

And one further comment and response to Mr. Huber's statement about parties asking relatively little questions on this RPS bill credit option. It is important to consider that one of the reasons for it is this option has changed and morphed a little bit over time. Initially it was proposed as a buy-all/sell-all agreement, which Vote Solar opposes as a general matter. Given that that was initially proposed as that, and Vote Solar would oppose any type of buy-all/sell-all agreement, we did conduct some discovery but it was relatively limited. It is only later in the course of the proceeding that the option evolved to be either a buy-all/sell-all credit or it could apply to exports only. So that was one of the reasons why there perhaps has been relatively little discovery and discussion of this issue so far in this case.

Vote Solar also supports full grandfathering, supports the recommended order in this case on full grandfathering, and was happy to see Commissioner Tobin Amendment 1 which would further clarify this issue that the default position of the Commission should be that customers are grandfathered as of the date of a Commission decision and not based on some retroactive date when the utility gave some form of notice to solar customers.

Finally, Vote Solar also supports SWEEP's proposed revision to Hearing Division Amendment 4. There is ample evidence in this case that the current basic service charge is sufficient to recover the actual fixed costs of the company. And, in addition, Vote Solar agrees that it would be appropriate to have a lower fixed charge for TOU rates as a matter of incenting customers to choose TOU rates.

For these reasons Vote Solar recommends that the Commission delay resolution of all aspects of the solar rate design proposals until phase two.

Thank you.

CHMN. LITTLE: Thank you very much, Mr. Hiatt. I think Commissioner Stump has a question for you.

COM. STUMP: Thanks, Mr. Chairman, clarifying question.

Mr. Hiatt, as I read Stump No. 1, this does nothing to weaken net metering. It simply provides an optional rate for customers. Why are you opposed as well?

MR. HIATT: It is an optional rate, and that's one of the strengths we see in this option. But it would, if this were to be implemented as the sole mechanism to compensate solar exports, it would eliminate net metering because exports would be compensated lower than retail rates.

COM. STUMP: It is an option. It is not the sole option. It is a choice.

MR. HIATT: We agree with options and feel this would be something which potentially we might support, but it needs further discussion, and just that the policy implications of what stepdown and how quick it would go is the kind of information we would need more information on.

COM. STUMP: You would agree this does not adversely affect net metering?

MR. HIATT: If it remains optional, all customers could continue to choose full retail --

COM. STUMP: Right.

MR. HIATT: -- rate net metering, then --

COM. STUMP: It starts actually at the retail rate.

Okay. So, to clarify, if this amendment were to pass, it would not affect net metering adversely at all in your opinion?

MR. HIATT: As raised now as an optional rate, yes --

COM. STUMP: Okay.

MR. HIATT: -- I believe --

COM. STUMP: Okay. Thanks.

MS. KOBOR: May I add one additional detail?

I think the primary concern that Mr. Hiatt is expressing over the stepdowns is, based on our calculation, we would expect to blow through several of the stepdowns prior to getting a decision in phase two of this proceeding. Namely, the first stepdown would be reached around mid January, the second one at the beginning of April. So depending on when that decision comes in, we may be in step two certainly, very likely in step three by the time we get that decision.

To clarify, as an optional rate that does start at the retail rate, this would not negatively impact net metering. And we are supportive of options. Our concerns primarily relate to the speed at which this goes down. And, you know, if it were to be expanded significantly, you know, on the order of a year per stepdown or something, that may change our position.

COM. STUMP: Mr. Chairman, ma'am, if we were to complete the value of solar docket by October, then there would presumably be little problem, correct?

MS. KOBOR: Well, I believe phase two of this proceeding wouldn't be completed until March based on the proposed amendments, but you are correct.

COM. STUMP: But if we were to --

CHMN. LITTLE: Go ahead.

COM. STUMP: I am sorry, Mr. Chairman.

If we were to -- and that's Commissioner Little's amendment, but I believe Mr. Tobin has an amendment to complete the value of solar by October. So if we were indeed to complete the value of solar docket with alacrity, which I believe the parties agree is important to address these issues swiftly as opposed to delaying, then how would that affect the step number one in providing more options to DG options?

MS. KOBOR: So my understanding is that we anticipate the outcome of the value of solar docket to be clarity as to the methodology for calculating the value of solar, but that calculation would actually occur in phase two. So we would get clarity as to the methodology, but we would not have the actual number to compare to this RPS bill credit option until phase two.

COM. STUMP: Okay. We will disagree with some of those details.

We need to be able to set a hearing at a reasonable time.

So looking at those time tables, that's where I came up with the date of March. So, you know, and I think considering that we have a Thanksgiving and Christmas holiday in there in that intervening time, plus we may have some new Commissioners that, well, we definitely will have some new Commissioners potentially that will need time to get up to speed on those dockets, that's sort of the rationale behind where that date came from. But it certainly doesn't mean that's the date. That's a "not later than" date.

So fair enough?

MS. KOBOR: Yes.

CHMN. LITTLE: Okay. Thanks.

Mr. Huber.

MR. HUBER: Chairman, Commissioners, delay, cloud, save for future date to study, these are going to be themes you are hearing from certain parties today. And I want to give us just an illustration of that just right now where Ms. Kobor came up and said, well, this is just going to be blown through, they are not set up correctly.

These stepdowns were set up to match RPS compliance. We really don't need that much. We don't need to go above 4 percent, which we are already at. The entire REST standard is 4.5 for DG. Okay? So they are set on REST standards, too.

This is always meant to be an optional rate. So you will have customers that pick the net metering option. Right? So we have never assumed that everybody will pick this one option. So it is meant to exist, to coexist.

Furthermore, it is clearly stated that we will revisit the stepdowns and where we are at and give you all the flexibility to see how it is working, to maybe change the stepdowns, put more capacity in a certain bucket, and so forth.

And I think it is, it is really shocking to see that RUCO made one small change to accommodate Vote Solar and TASC to allow the option of self-consumption and exports, we make one change and that is the reason why we actually have to reject this, because we don't have enough information now about a change that we made to accommodate them. And, again, it is a small change. It doesn't actually impact any of the numbers. It simply is an option. So thank you.

CHMN. LITTLE: Thank you, Mr. Huber.

So, Mr. Hiatt, anything else?

MR. HIATT: Just one quick response to that last point. We respectfully disagree with Mr. Huber, that changing an option to a buy-all/sell-all, to an optional buy-all/sell-all is more than just a small change. It is a fundamental change. And it definitely changed our position on that option.

CHMN. LITTLE: Okay. Mr. Rich, quickly.

MR. RICH: Thank you, Commissioner.

I think one thing that Mr. Huber said struck me. He talked about how at the end of phase two we could adjust the stepdowns or make other modifications. Well, that's, frankly, our issue with this. It is presupposing what the outcome of phase two is going to be.

If the Commission is going to go through the phase two and make it as useful as possible with the goal of coming up with the answer being informed by the value of solar docket, then why would we put one in place and act like we are presupposing the outcome or the methodology or the mechanism that we will use in that docket? And that's our point. We may very well be back here embracing this option after it is more fully vetted. But it is just, it is cart before the horse in our opinion.

And to Mr. Huber's accusation that people are talking about delay or kicking, or whatever his language was, this is the ROO's idea with which we were agreeing, the phase two. And so I do take umbrage with that characterization.

CHMN. LITTLE: Certainly. Thank you, Mr. Rich.

Okay. What I think I would like to do, and at this point I have exhausted the table, so what I am going is do is go to the service list and see if there are party that -- yes?

Oh, no, I have several more people.

And, I am sorry, you are?

MR. MOYES: Jason. Good morning, Commissioners, Chairman Little. I am Jason Moyes on behalf of the Fresh Produce Association of the Americas. I apologize I didn't have a seat at the table earlier.

CHMN. LITTLE: We don't have tables big enough for all the people in this case.

COM. FORESE: Something funny about no room at the table for produce.

MR. MOYES: It seems we always end up going last in these proceedings. Hopefully that's not a bad thing, but...

I wanted to first start off by thanking Judge Rodda, along with others, for the incredible amount of work that she put into this in analyzing very complex issues. We are very appreciative of her pointing out in

No. 1 say aye.

(A chorus of ayes.)

CHMN. LITTLE: Is that five ayes? Five ayes, zero nays, it has been approved.

And now we are to Commissioner Stump Proposed Amendment No. 1.

COM. STUMP: Thanks, Mr. Chairman.

I would just for the record note that five months ago several parties did indeed cross-examine Mr. Huber on the RPS bill credit option. I have the transcript right in front of me.

For your edification, on page 2,308 -- hard to believe that exists -- Ms. Dittelberger from Vote Solar cross-examined Mr. Huber:

Let's talk about the RPS bill credit option. So this option you clarified is a buy-all/sell-all tariff, correct.

Mr. Huber responds: For lack of a better term, yada-yada-yada.

On page 2,317, Mr. Rich, representing TASC, cross-examined Mr. Huber. He said: And with regard to the RPS bill credit option you have got, if I understand you correct, a customer, you would agree a customer pays tens of thousands of dollars potentially for a solar facility, correct, put on the roof?

Mr. Huber responds: Depending, blah-blah-blah.

Ms. Grabel cross-examined Mr. Huber, et cetera, et cetera.

So I just wanted to let everybody know that is indeed there.

CHMN. LITTLE: All right. Comments from parties on Stump Proposed Amendment No. 1?

MR. RICH: Chairman Little.

CHMN. LITTLE: Mr. Rich.

MR. RICH: Thank you. Surprise again.

CHMN. LITTLE: Actually, no, I wasn't surprised.

MR. RICH: I hear you.

Commissioner Stump, so one thing that wasn't talked about yesterday, and certainly I can review some of the things but I don't need to go into the issues that we identified, one of them that I think is key, frankly, and I am disappointed I didn't think of it yesterday, but is the cost to implement this program. And I don't think there is anything, in fact I know there is nothing in the record about what it would cost the company to implement this program.

And, again, you know, it is an optional program, as we have talked about. It is liable to be and likely to be either altered or done away with in just a few months. So I think certainly before we would adopt a new program, that would be an important point on which there was nothing in the record. So, otherwise, I certainly stand by the comments that we made yesterday. And I may have one other here in a second as well. Thank you.

COM. STUMP: Thanks.

Mr. Chairman, with your indulgence.

CHMN. LITTLE: Please.

COM. STUMP: Mr. Hutchens.

I think, actually, Mr. Rich, you did touch on that point of implementation yesterday.

But, Mr. Hutchens.

MR. HUTCHENS: Chairman Little, Commissioner Stump, surprisingly it is only minimal cost because we already tracked this at just -- there is no additional software changes that we need to make. It would just create a whole bunch of different customer tiers, which we fully expect in the future anyway.

CHMN. LITTLE: Okay.

COM. STUMP: Thanks.

CHMN. LITTLE: Thank you very much, Mr. Hutchens.

MR. HIATT: Chairman Little, if I may.

CHMN. LITTLE: Mr. Hiatt.

MR. HIATT: Michael Hiatt on behalf of Vote

Solar.

I just would like to clarify for the record yesterday some parties might have suggested that Vote Solar might support Stump No. 1. I want to make it clear for the record Vote Solar opposes Stump 1. We have concerns about how the tranches are structured, how quick they would go to impacting the solar industry. So we oppose the amendment on that ground.

CHMN. LITTLE: Okay. Thank you very much. I was are pretty clear that you guys were opposing it.

MR. HIATT: I just want to make sure. Thanks.

CHMN. LITTLE: Mr. Patten.

MR. PATTEN: Just following up on our comment yesterday of moving the 60 days to 120 days.

COM. STUMP: Yeah. And, Mr. Chairman, with your indulgence, I think we solved that by an amendment to the amendment saying 120 days, fixed bill credit, change 60 to 120 days. And then add "of the effective date of this order" after 120 days and before the word per the general, or before the phrase per the general program design.

CHMN. LITTLE: Right. And I had actually made that notation on my copy as well.

COM. STUMP: Okay, great.

CHMN. LITTLE: Okay.

MR. RICH: Your Honor -- or Your Honor. Your Honor is a fine marker, I am sure.

Chairman Little, if I may, I thought yesterday that we heard it was going to cost somewhere around a million dollars just to do shadow billing, which is data that the company already has. And I wonder, if they already have this data, why this is apparently no cost to them to implement this and if they have plans for how to implement to communicate the tranches and where they are at to the installers and the customers that will be trying to sign up for this program but will not have visibility into what tranche they are in and how that would work.

CHMN. LITTLE: Well, I think, I don't want to put words in Mr. Hutchens's mouth, but my memory serves that the discussion yesterday that would have been quite expensive would have involved multiple shadow bills. I don't think this particular item involves a shadow bill.

Mr. Hutchens, or I will --

MR. HUTCHENS: No, it doesn't.

CHMN. LITTLE: And to Mr. Rich's other question, would there be some easily available information for, let's say, the sales staff of a solar company that wanted to identify where you were on a particular tranche, you could -- they would be able to have access to something like that?

MR. HUTCHENS: Chairman Little, I highly doubt it. I mean things happen so quickly. You have so much in the queue. You know, we could do periodic reports, but they would have to tell us how many people they are getting ready to sign up, too. So, you know, we don't have any issue related to communicating as best we can, but there is probably no complete solid way for us to do that with any high degree of accuracy.

CHMN. LITTLE: Okay.

MR. RICH: Well, Chairman Little, I think, I mean I think that underscores, if I may, I think that underscores one of the issues here. If they don't even have the ability to communicate effectively right now that they are aware of, or can articulate, you know, where they are at in the tranches and we are proposing something with such small tranches, I just don't see how that's workable.

And, again, this is the exact kind of thing that's going to be on the table for discussion for review. It may be something that we are back here supporting, but it is not right now.

And so I don't think there is a reason to pick this one among all the other options that were provided and discussed, all of which the judge found were, you know, not ready to be decided upon at this point.

MR. HUBER: Chairman.

CHMN. LITTLE: Mr. Huber, please.

MR. HUBER: Chairman, Commissioners, again, delay, cloud, push out to study. We actually had the same general process for up-front incentives. And although it wasn't a perfect system, the utilities were able to send communications out to installers. Now, was it to the exact minute? No, but they managed that process without very many complaints. So I think the utilities can handle this one.

And I think that these tranches are sized perfectly to the UniSource service territory and to REST compliance targets. And, again, this is an optional rate. Right? So this isn't -- everybody that's going solar probably won't pick this, but optional for them, so...

COM. STUMP: Mr. Huber, didn't you introduce -- Mr. Chairman, pardon me -- introduce this concept in December of 2013?

MR. HUBER: Well, yes. So December -- and so this gets to an interesting comment that Ms. Kobor made yesterday where we had only 24, 48 hours to review this. Well, I submitted it in 2015, Commissioner --

COM. STUMP: '13.

MR. HUBER: Well, in this particular docket --
COM. STUMP: Right, right.
MR. HUBER: -- in 2015 --
COM. STUMP: Pardon me.
MR. HUBER: -- I put the capacity tranches and the numbers out there in testimony. Commissioner Stump, you filed a letter asking parties to comment on it, or, and to talk about it in the docket. Filed again on the 29th of last month the exact same things I filed in December of 2015. And, again, Ms. Kobor claims they only had 24, 48 hours to review it. So I think there is a little bit of a credibility gap here.

And I mean one of the points that I would just like to make, Commissioner Burns, you also submitted a docket, a letter to the docket that said look at export rates. And, again, that really wasn't -- that was largely ignored by some of the solar parties.

And, Commissioner Tobin, you are, you know, focused on this cost drive of peak demand. And RUCO put forward a rate that addressed specifically that, how to encourage more on-peak demand technologies. I actually had more questions from Mr. Rich about my boss's background and how my boss created a nonprofit educational organization for energy storage than I actually had on this advanced DG demand response rate.

So I just, I want to keep that in focus where, you know, we need to work together to solve these problems. And I am not really seeing that happening right now. And it is unfortunate because I do think there is a lot of agreement out here that we can have. And we have got a great option in front of us that we should explore where you can send locational price signals through the grid through this option. You don't have to worry about grandfathering. You have got flexibility and check-ins repeatedly on this. So a lot of benefits in this policy for us to explore, and we shouldn't delay it.

COM. STUMP: And, again, Mr. Huber, this is, as I see it, a pro solar amendment that simply offers solar customers another choice. It is as simple as that.

Mr. Hutchens, I think you commented the other day that the schedule of sign-ups for solar basically was very much compatible with the tranche stepdowns, is that correct? Or I think it was maybe someone else from the company.

MR. HUTCHENS: Chairman Little, Commissioner Stump, I am not sure if that was me or not. I might have thought it. Maybe I thought it out loud, but I can't recall if that was me who said it. But that seems right.

MR. HIATT: Chairman Little.

CHMN. LITTLE: Mr. Hiatt.

MR. HIATT: If I may quickly, since Mr. Huber questioned the credibility of Vote Solar.

One key point, which was raised yesterday but just to highlight again, is that when Mr. Huber initially proposed this proposal, the dates he mentioned it was a buy-all/sell-all proposal. That was a critical threshold issue, which Vote Solar's position opposed it on that basis alone. It has changed since then to not be a buy-all/sell-all, which is more amenable to Vote Solar. But that explains why Vote Solar perhaps did not engage in thorough discovery initially, because it was a different proposal at that time.

Thank you.

COM. STUMP: Guys, I have to be honest with you. I think I could put out anything here and you would oppose it, quite frankly. That's the sense I am getting.

Here we have a pro solar amendment that is innovative. You claim to be in favor of solar customers. It is simply another choice, a benign choice, allowing solar customers to have yet another choice. You claim to be pro choice. I, frankly, get the feeling that anything that I put out here you are going to oppose and throw the kitchen sink. And once the kitchen sink is thrown out there, I will have another household appliance thrown at me, so...

Anyway, Mr. Huber, you wanted to say something.

MR. HUBER: Yeah, Chairman, Commissioner Stump, again, it is sad. So a ratepayer advocate gets a bait and switch, which we responded to the concerns of solar parties by adding an option. So it is still the same crediting mechanism as before, but we responded to the solar parties about the need to keep self-consumption on the underlying retail rate.

So we responded to their concerns. And now, by doing that, they are saying, they are undermining this policy proposal. So it is just, it is just striking that this can happen.

COM. STUMP: Mr. Chairman, I don't know about you, but I am ready to vote once Mr. Rich makes his comments.

CHMN. LITTLE: Mr. Rich, one more.

MR. RICH: Thank you, Chairman, Commissioner Stump.

To respond to your comments, Commissioner Stump, there were numerous measures that were considered in this docket. And there are, you know, RUCO alone proposed four or five or six different variations within the six. There were lots and lots of things that were discussed.

I think the point is, you know, and Mr. Tobin has just proposed another thing that we should discuss in phase two, it doesn't, in my mind it does not make sense to adopt one today and put it in a position that presupposes that it has any more viability or any more worth than the other ones that are going to be examined in phase two. And I think there are significant problems with it as is. And, again, it may be, the framework may be right eventually, but we need to look at that. And there is no kick the can. There is a wall at the end of this proceeding. It is phase two.

You have already decided the Commission, it appears, is going to demand and I believe Chairman Little has a resolution of all these issues in phase two. And so it makes no more sense to pick this one that is, you know, is not right right now and make it an option than it does any of the other ones.

And so that's, that's where we are coming from. It is not a don't do anything. It is just in this format at this point in time, with the prospect of getting it right right around the corner, we would ask that you not just pick this one, even if it is just optional.

COM. STUMP: Mr. Rich, it is over and over again not doing anything. And here we have an option today. It doesn't affect net metering one wit, one iota. It doesn't even affect the value of solar docket, entirely separate item. And you claim to be in favor of solar choice. And here we have right here, no one else seems to have a problem with it, a pro solar amendment that's simply gives consumers more choice that has been vetted on the record. You yourself asked questions. And here we go again.

Mr. Chairman, that's all I have to say.

MR. RICH: Chairman, Commissioner Stump, just if I could really briefly. It is not pro solar in that it steps down in a manner that is not conducive to the future of solar. And so in that --

COM. STUMP: That's your opinion. No one else seems to view it that way, Court. Anyway, the Commission is the decider. We will see where it goes.

CHMN. LITTLE: So I think we are pretty clear where people stand. So at this point, Commissioners, is there any discussion of the amendment?

(No response.)

CHMN. LITTLE: Seeing none, all in favor of Stump Proposed Amendment No. 1 say aye.

(A chorus of ayes.)

EXHIBIT B

So I make it real simple. I think it is appropriate that we look at the cost for the meters specifically because there seems to be no argument there in that the remaining parts of that seem to have to do with costs and I think are best included in our phase two and final formularies.

So my, the Tobin 3 amendment basically says yes to the $1.58 meter cost and that the rest would move to the, to the value of solar docket in phase two.

CHMN. LITTLE: So if I understand you correctly, just to restate what you just said, so the $1.58 charge associated with the physical meter is very clear --

COM. TOBIN: Right.

CHMN. LITTLE: -- there is a question about the allocation of the $1 meter reading fee I think along the lines of, if you have somebody there physically reading a meter already, what is the marginal cost of reading a second meter when you are standing right there?

COM. TOBIN: Yeah.

CHMN. LITTLE: And then there is some question on, you know, the allocation of the billing and collection fee based on just the recalculation. So what you are basically saying is that you are willing to do the $1.58 but the others should be evaluated as part of the value and cost of solar, or, excuse me, as part of phase two?

COM. TOBIN: Right. I don't think there is any question that everybody agrees on the meter. I think that's pretty much basic when we move the rest along.

CHMN. LITTLE: I just wanted to make sure I, number one, understood and could articulate exactly what we were doing here.

Comments from the company?

MR. HUTCHENS: Chairman Little, yes. I think maybe it would provide a little bit of information. I know we got some questions related to it before the break on where these costs came from. So if it pleases the Commission, we could have Craig Jones, who is our cost of service expert, talk about where those came from. Prior to that, I would just opine that we would think that the 6.95 that we had offered is justified. But we can quibble about that after Mr. Jones talks.

CHMN. LITTLE: Okay. Mr. Jones, good afternoon.

MR. JONES: Yes, Mr. Chairman, Commissioners.

I have worked on the cost of service. As you guys are fully aware, a typical cost of service is submitted based on imbedded costs, evaluation of various cost components. And that is what is being reflected in these various customer related components that you are seeing described here. But the key thing I think from my perspective to remember is that is an imbedded cost study, when things that -- all the costs of the meters, the system associated with providing the bills, collection of those bills, and the meter reading itself is on an imbedded cost basis, which means anything and everything over the last however many years is fully depreciated or averaged cost. It is over all the meters serving all the customers.

So we look at this as a conservative step in the direction of helping to recover some of the costs associated with a brand new meter that would be installed to provide service to the new net metering customer. And so these are very conservative overall.

COM. TOBIN: So we are really talking -- excuse me, Mr. Chairman. So we are really talking about this $5.37 left, right? Because my amendment agrees to the $1.58.

MR. JONES: Correct.

COM. TOBIN: Okay. So of the, just so, because I am simple minded here, just on the 4.37, would you kind of repeat that, why it is that you think that's, that should be included.

MR. JONES: Certainly.

COM. TOBIN: Thank you.

MR. JONES: The billing collection cost itself is in fact part of the billing system. I mean the cost associated with providing the bills, getting the bills out, conveying the bills, all of that, that particular cost is included in that number. And the net metering bills are, in fact, one of the more complicated bills that we issue. But keep in mind this number is an averaged number over all bills, even though the most simple bill. And so we felt this, again, would be a representative number to get us moving in the right direction.

CHMN. LITTLE: Let me just ask a question. I think this is the crux of it. You are already sending -- well, wait a second. Let me just back that up.

Okay. Never mind. I am processing a little slower this time of the day.

MR. JONES: That's okay.

COM. TOBIN: I mean we are talking about moving this -- oh, okay. Good. I see somebody else wants to jump in while I put my tongue back in and figure what I want to say right.

MS. KOBOR: Thank you, Chairman, Commissioner. I just wanted to clarify that we do not oppose the $1.58 charge. We agree that there is an additional meter and that it may be appropriate to include the capital cost specific to solar customers.

In regards to Mr. Jones' most recent remarks, we do not think that there is evidence in the record to indicate what, if any, share of the $1 meter reading and $4.30 billing and collection fee study would need to be done to assess the marginal cost of those services for having the additional meter. What I believe I heard Mr. Jones just refer to is the fact that even the $1.58 comes out of an imbedded cost study. And so that does include depreciated costs. We expect the NEM meters to be of a different vintage than the entire class of meters. However, again, that would require additional study.

So at this point in this process, what we have is $1.58 as a capital cost. We can accept this proposed amendment. There may be a small legal clarification with something, so I don't want to speak to that just yet, but as far as the dollars here, we can accept and would intend to investigate the additional cost in phase two to determine an appropriate value.

COM. TOBIN: Sell me on the cost. Split it out for me.

MR. JONES: Certainly. As far as information in the evidence, you know, actually on the record, in my direct testimony, I believe it was CAJ-1 in my direct testimony, we did submit a marginal cost study. And that is a study that identifies each of the cost components of a new install. And it will show the cost of new meters, which we are talking about applying this prospectively to new net metering customers going forward. And that marginal cost study would show there is substantial costs to the actual meter that would be over and above the $1.58 that you see here.

COM. TOBIN: For billing and collections or just on the meter itself?

MR. JONES: I am just talking about the meter itself.

COM. TOBIN: Okay. So we are back on the meters.

MR. JONES: Yeah.

COM. TOBIN: So it is not a buck 58.

MR. JONES: I just want to make sure I don't --

COM. TOBIN: Don't confuse the facts.

MR. JONES: So it would be substantially more than $1.58.

Okay. With that said, the other component you mentioned was the $1 for the meter reading itself. And, you know, I understand your concern about wait a sec, you are there, you are reading it anyway. But remember that dollar is recovering the cost of the meter reading system and the fact that those costs are averaged over each individual meter that we have. So if there are two meters there, gathering data off two meters, it is averaged across that. So, you know, we believe that if you add all the pieces together, it is a very representative step in the right direction.

COM. TOBIN: I am still trying to figure out how we separate the, you know, this extra meter into this dollar and into this $4.37. You replied to me that really the $1.58 isn't the right number. It is too low.

MR. JONES: It is too low.

COM. TOBIN: It is too low. I get that. But you can understand my confusion, because you asked me in this one for the $1.58. Help me.

MR. HUTCHENS: Chairman Little, Commissioner Tobin, so what we are trying to do here is, again, a moderate step. If you use the marginal cost study as you mentioned earlier, Commissioner Tobin, I don't want to get yelled at again, but not looking at gradualism or making sure that we are providing small --

COM. TOBIN: I did not yell at you. I did not yell at you.

MR. HUTCHENS: It was more of a frown, but yes.

COM. TOBIN: Okay.

MR. HUTCHENS: So that's why we thought the

$1.58 is right there. The dollar is, as Mr. Jones explained, look, if you want to divide it by how many -- the system over meters, that's how this turns out. So a dollar to me is clear and appropriate to collect for that service.

So the conversation then kind of revolves around this remaining $4.37, which is billing and collection. And remember that when we first started doing net metering we needed an entirely different system. I mean tons of money was spent setting up specifically to do this kind of thing. We are not asking that. We are not asking for the marginal cost of what we have had to do in our billing systems to supply this information divided solely by the number of net metered customers. We put that all together and divided by the total number of meters.

So we think this is conservative. We think there, you know, if we were to do this in terms of what I think you would probably like to see, there is solid, completely solid evidence for the $1.58 and the dollar meter reading charge.

If we want to figure out, well, if you look at that billing system and you looked at it a slightly different way, should you really be charging $4.37 additional by meter, and, you know, we can discuss that

that's a number that we would be willing to compromise, although I realize I am negotiating here against myself, but, again, in the spirit of compromise, half of that charge -- and, by the way, when I negotiate I usually go right to the number that we really think is the minimum that we could accept -- and that, to me, would be an appropriate compromise.

MR. RICH: Chairman, can I respond?

CHMN. LITTLE: Mr. Rich.

MR. RICH: Just a piece of information to add to this discussion, and your Staff can certainly confirm, there are some utilities that have this charge, this meter charge, and they pass it on to the solar customers and the customers pay it. But the precedent at the Commission has never been to include those other buckets. They do not currently include billing and collection or meter reading as part of those charges. And so I think you are right on with this amendment.

CHMN. LITTLE: Mr. Huber. Mr. Huber has got -- he raised his hand. Mr. Huber.

MR. HUBER: Sorry. Chairman, Commissioners, we think that the conservative -- that the company is actually taking a very conservative view on those costs, and would just like to remind this is just an interim step. So if we get the rate design, if we improve rate design in phase two, this charge can come down. It could go away. We could maybe look at the marginal cost. But I think getting a number here that's easy to understand that sort of splits where we are at I think is very conservative and completely justified.

CHMN. LITTLE: So, Mr. Huber, you didn't even want to be in my office during the lunch break because we were opining about what happens as the smart meters start to deploy, because then you only have one meter instead of two and what do you do in that case. But I don't think we want to complicate it that much.

COM. FORESE: We will cross that meter when we get there.

CHMN. LITTLE: Ms. Kobor, are you waiting?

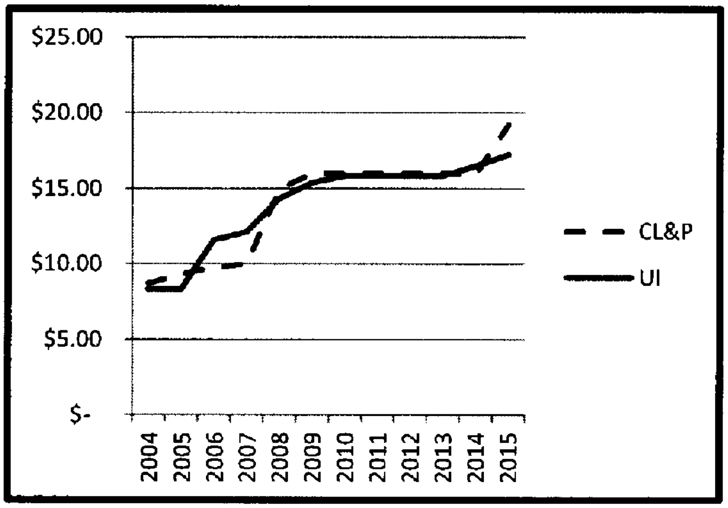
MS. KOBOR: I would just, I would just continue to state what I believe Mr. Rich was referring to is my reading of the other charges as well, that it is only the meter fee. It does not include a meter collection.

When I look through the cost of service study, I look at the types of categories of accounts that go into that $1. It is a very round number, but it does have numbers behind it. And those include like an administrative and general expense adder, supervision, in addition to the meter reading expenses, customer assistance expenses, informational and instructional,

EXHIBIT C

CT Law Requires Reduced Fixed Charges for Electricity

In 2015, Connecticut's electric customers won legislation to stop runaway fixed charges. Fixed charges are flat monthly rates that the customer must pay just to have access to electricity. Over the last decade, fixed charges for residential customers increased by more than four times the rate of inflation – to the **highest (Eversource, $19.25/month) and second highest (UI, $17.25/month) in New England** for any major electric utility. Eversource residential customers in MA pay monthly fixed charges of less than $7.



CT's Residential Fixed Charge (2004 to now)

Eversource/CL&P – up 121%

United Illuminating (UI) – up 107%

(cumulative inflation only 25% over same period)

New CT law clearly limits what costs can be included in the fixed charge:

"…only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service." (CT General Statute § 16-243bb)

The **Office of Consumer Counsel (OCC)** has submitted expert testimony showing that **UI's residential fixed charge should be $7.63/month under the new law.**

High fixed charges reduce consumers' control over their energy costs and hurt progress on energy efficiency and clean energy, hindering the growth of a green jobs economy.

Fixed charges fall hardest on those customers who use the least electricity, and they devalue investments in efficiency and renewables.

Tell PURA to enforce the law: reduce UI's residential fixed charge.

1. **Endorse our online statement at bit.ly/UI9-16**
2. **Attend one of the public hearings:**

Bridgeport - Thursday, September 8 at 6:30 p.m
City Common Council Chambers, City Hall, 45 Lyon Terrace

New Haven - Monday, September 12 at 6:30 p.m.
Kennedy Mitchell Hall of Records, Hearing Room G2, 200 Orange Street

CT Roundtable on Climate and Jobs
Contact: John.Humphries1664@gmail.com; 860-216-7972

Acadia Center
Contact: wdornbos@acadiacenter.org

More info: www.CTEnergyRelief.org

8/26/16

*** Current through all Public Laws approved by the Governor as of May 24, 2016 ***

Title 16 Public Service Companies
Chapter 283 Telephone, Gas, Power and Water Companies

Conn. Gen. Stat. § 16-243bb (2016)

Sec. 16-243bb. Adjustment of electric distribution company residential fixed charge.

(a) As used in this section:

(1) "Residential fixed charge" means any fixed fee charged to residential electric customers, including, but not limited to, (A) a fixed charge for distribution basic service, (B)a distribution customer service charge, (C) a customer charge, or (D) a basic service fee which is separate and distinct from any distribution charge per kilowatt-hour.

(2) "Electric distribution company" has the same meaning as provided in section 16-1.

(b) The Public Utilities Regulatory Authority shall adjust each electric distribution company's residential fixed charge upon such company's filing with the authority an amendment of rate schedules pursuant to section 16-19 to recover only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service.

(c) The provisions in subsection (b) of this section shall not permit or enable the authority to cause a cost shift to other rate classes.

(d) This section shall not apply to electric customers that subscribe to a residential electric heating service rate class.

HISTORY: P.A. 15-5, S. 105, eff. July 1, 2015.