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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE, CHAIRMAN
BOB STUMP, COMMISSIONER
BOB BURNS, COMMISSIONER
TOM FORESE, COMMISSIONER
ANDY TOBIN, COMMISSIONER

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 **ENERGY FREEDOM COALITION OF AMERICA'S NOTICE OF FILING SUPPLEMENTAL TESTIMONIES OF MARK E. GARRETT AND R. THOMAS BEACH**

The Energy Freedom Coalition of America ("EFCA") hereby files the attached Supplemental Testimonies of Mark E. Garrett and R. Thomas Beach.

RESPECTFULLY SUBMITTED this 15th day of September, 2016.

/s/ Court S. Rich
Court S. Rich
Rose Law Group pc
Attorney for EFCA

Original and 13 copies filed on this 15th day of September, 2016 with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
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BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE
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SUPPLEMENTAL TESTIMONY

OF

MARK E. GARRETT

ADDITIONAL METER CHARGE

ON BEHALF
OF

ENERGY FREEDOM COALITION OF AMERICA ("EFCA")

September 15, 2016

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Mark E. Garrett. My business address is 50 Penn Place, Suite 410, 1900 NW Expressway, Oklahoma City, Oklahoma 73118.

Q: DID YOU FILE DIRECT TESTIMONY IN THIS DOCKET ON JUNE 24, 2016?

A: Yes.

Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?

A: I am appearing on behalf of Energy Freedom Coalition of America ("EFCA").

Q: WHAT IS EFCA'S INTEREST IN THIS PROCEEDING?

A: EFCA's primary interest in this proceeding is to maintain and encourage consumer choice and fair rates, 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.

Q: WHAT IS THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY?

A: The purpose of this supplemental testimony is to address TEP's request to include a Solar Meter Charge for all new net metering customers for the additional meter required for DG service.

Q: WHAT IS TEP PROPOSING FOR A METERING FEE FOR NEW NEM CUSTOMERS?

A: TEP is proposing an incremental metering charge for all new net metering customers that is based on TEP's 2015 Marginal Cost Study. In his direct testimony, TEP witness Craig A. Jones proposes an additional meter fee of $8.62 for residential net metering customers and $9.13 for new SGS net metering customers.[1]

Q: HAS RUCO PROPOSED AN ADDITIONAL METER CHARGE?

A: Yes. RUCO witness, Lon Huber suggests adding a monthly additional meter charge of about $6. He also uses TEP's marginal cost study to determine the amount of his charge.

Q: SHOULD THIS ISSUE BE DECIDED IN THIS PHASE OF THIS DOCKET?

A: No. This issue should be considered in Phase Two of this docket. In the UNS docket, the Commission allowed a meter charge for the embedded capital cost of the additional meter equipment while not including any of the associated costs. What the Company is asking for in this case is the marginal cost of the meter equipment plus the associated costs.

In the UNS docket, the Commission stated that the Value of DG docket is considering mechanisms for determining the value and costs of solar DG, and that it would be appropriate to apply those findings in Phase Two when considering whether charges for a second meter should be assessed.[2] It is reasonable to follow the same logic in this docket.

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[1] Jones at page 24, lines 1 - 16

[2] Decision No. 75697 at page 140, lines 6 - 15.

Q: SHOULD THE ADDITIONAL METER CHARGE BE BASED ON MARGINAL COST RATHER THAN EMBEDDED COSTS AS THE COMPANY SUGGESTS?

A: No. TEP claims that an embedded cost estimate understates what the incremental meter costs should be by a substantial amount. TEP further asserts that the number used in the CCOSS is an average of all meters in service regardless of how close they are to being fully depreciated. This additional meter charge is for new customers and new installations, therefore the marginal cost data presented by the Company in the Direct Testimony of Craig Jones at Exhibit CAJ-1 is the appropriate source for this information.[3]

Q; DO YOU AGREE WITH THE COMPANY'S LOGIC?

A: No. The idea that marginal costs should be used for rate design purposes because the Company is installing new meters makes no sense. In designing rates, we do not use marginal costs for new assets and embedded costs for old ones. Ultimately, all costs collected from ratepayers must reconcile back to the Company's embedded cost of service. Thus, marginal cost of service studies are sometimes used to allocate costs between rate classes, but the costs that are ultimately collected from ratepayers must be the embedded costs of the utility. Furthermore, since the primary purpose for using marginal cost pricing is to send a price signal to ratepayers to inform their decisions, it would only make sense to use marginal-cost pricing when there is a decision to be made. In the case of additional meters, DG customers do not have a decision to make; they are required to have a second

[3] Jones at page 24, lines 2 - 6.

meter. Thus, embedded cost is the better way to collect the actual costs represented in an additional meter charge.

Q: WHAT DID THE COMMISSION DO IN THE UNS CASE?

A: In the UNS case, the Commission approved only the embedded capital cost of a meter, a monthly fee of $1.58. The Commission stated,

> [T]here is one aspect of the DG rate design that we believe should be modified at this time. The record in this docket reflects that each DG customer requires a second meter, and that there are additional fixed costs associated with that second meter. The additional cost for the meter is $1.58.[4]

The Commission specifically stated that it expected the Value of DG docket to provide general guidance on the fixed costs of a second meter for DG customers, and directed parties to file testimony "evaluating the other foists for the second meter" in Phase Two, after the Value of DG docket.[5]

Q: HAVE YOU CALCULATED AN ADDITIONAL METER CHARGE IN THIS DOCKET THAT IS CONSISTENT WITH THE COMMISSION'S DECISION IN THE UNS DOCKET?

A: Yes. I calculated an Additional Meter Charge of $1.68 for residential customers and $5.60 for General Service. This calculation can be seen in Exhibit MG-Supp 1.[6]

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[4] Decision No. 75697 at page 118, lines 9 - 12.

[5] Id. at page 118, lines 21 - 25.

[6] TEP Schedule G-6-1 shows a Customer Meter cost of $0.32, but I question whether this amount is properly calculated, or if perhaps the amount is mislabeled.

Q: OTHER THAN THE FACT THAT THIS ISSUE SHOULD BE DECIDED IN PHASE 2 OF THIS DOCKET, IS THERE ANY OTHER REASON WHY YOU BELIEVE AN ADDITIONAL METER CHARGE IS INAPPROPRIATE?

A: Yes. Typically, ratepayers pay only the necessary costs of providing service. Since these additional meters are not required to provide service to DR customers but are instead needed by the Company to collect RPS data, there is a legitimate question about whether DG customers should be required to pay the entire costs of these meters through an additional meter charge.

Q: DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A: Yes, it does.

Tucson Electric Power
Extra Meter Charges with Depreciation
Docket No. E-01933A-15-0322

Description	ROR w/ Tax Gross up	Residential	General Service
Plant			
370 Meters		33,559,944	11,142,901
Less: Accumulated Depr.			
370 Meters		(2,923,361)	(970,643)
Net Plant			
370 Meters		36,483,305	12,113,544
Total Plant Rate Base (Meters)		**$ 36,483,305**	**$ 12,113,544**
Return	7.882%	$ 2,875,746	$ 954,833
Income Tax	3.582%	1,306,919	433,936
Return	11.465%	**$ 4,182,665**	**$ 1,388,769**
Depreciation Expense			
370 Meters		1,481,151	491,786
Other Expenses			
586 Meter Expenses		2,010,251	667,463
597 Maintenance of Meters		92,782	30,806
Total Extra Meter Related Expense		**$ 3,584,184**	**$ 1,190,055**
Total Return with Income Tax		**$ 7,766,849**	**$ 2,578,825**
12 Month Customer Count		4,624,512	460,872
Per Monthly Charge Extra Meter		**$ 1.68**	**$ 5.60**

TEP Inc Tax	75,394,570
TEP RB	2,104,677,691
Tax Calculation	3.582%

Less: Accumulated Depr.						
370 Meters				(2,923,361)		(970,643)
Net Plant						
Meters				36,483,305		12,113,544
Total Plant Rate Base (Meters)			**$**	**36,483,305**	**$**	**12,113,544**
Return	7.882%		$	2,875,746	$	954,833
Income Tax	3.582%			1,306,919		433,936
Return	11.465%		**$**	**4,182,665**	**$**	**1,388,769**
Total Return with Income Tax			**$**	**4,182,665**	**$**	**1,388,769**
12 Month Customer Count				4,624,512		460,872
Per Extra Meter			**$**	**0.90**	**$**	**3.01**

TEP Inc Tax	75,394,570
TEP RB	2,104,677,691
Tax Calculation	3.582%

All number developed from
TEP 2015 Revised Confidential CCOS

		Residential from Tab RS by Function Unless otherwise noted	**General Service Tab GS by Function** Unless otherwise noted		
Plant					
370	Meters	Cell D46	Cell D46		
Less: Accumulated Depr.					
370	Meters	Cell D78	Cell D78		
Net Plant					
	Meters	Summed	Summed		
	Total Plant Rate Base (Meters)				
	Return				
	Income Tax	3.58%	3.582%	Calculated Company Income Tax divided by RB	
	Return	7.88%	0.0788	Requested by Company	
Depreciation					
				TEP Inc Tax	75,394,570
370	Meters	Cell D27	Cell D27	TEP RB	2,104,677,691
				Tax Calculation	3.582%
	Other Expense				
586	Meter Expenses	Cell D163	Cell D163		
597	Maintenance of Meters	Cell D174	Cell D174		
	Total Extra Meter Related Expense	Summed	Summed		
	Total Return with Income Tax	11.46%	11.46%	Summed	
	12 Month Customer Count	G-6-1 Cell E43 Res times 12	G-6-1 Cell F43 GS		

BEFORE THE ARIZONA CORPORATION COMMISSION

DOUG LITTLE CHAIRMAN	BOB STUMP COMMISSIONER	BOB BURNS COMMISSIONER
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SUPPLEMENTAL TESTIMONY

OF

R. THOMAS BEACH

ON BEHALF
OF

ENERGY FREEDOM COALITION OF AMERICA ("EFCA")

September 15, 2016

Executive Summary

This supplemental testimony is submitted on behalf of the Energy Freedom Coalition of America ("EFCA") and addresses the proposal of the Residential Utility Consumer Office ("RUCO") to implement an RPS Credit option that would be available as an alternative to net energy metering ("NEM") for customers who install solar distributed generation ("DG"). The RPS Credit option would pay solar DG customers a rate ("the RPS credit") for their output that is fixed for 20 years, with the rate set at the time each DG system comes online. The fixed RPS Credit could apply either to the DG customer's entire output or just to the power that it exports to the grid. RUCO has proposed a schedule of declining RPS credits starting at the current retail rate and then decreasing according to a pre-set series of steps, with each step corresponding to a certain amount of DG capacity. The scheduled drops in the RPS Credit are supposed to track recent annual decreases in the cost of solar PV in Arizona.

The Commission should defer consideration of RUCO's RPS Credit proposal to Phase 2, notwithstanding that the Commission gave temporary approval to an RPS Credit option in the recent order in Phase 1 of the UNSE case. There are a number of issues with the design of RUCO's RPS Credit proposal that need further review in Phase 2, after the Commission completes its separate "Value of DG" proceeding. For example, RUCO has designed its proposal based on its own calculation of the long-term value of solar DG, which is the central issue that the Commission is reviewing in the Value of DG docket. Further, I show that RUCO's proposed declining series of RPS credits would result in far larger reductions in the compensation for solar DG customers than is supported by recent data on the actual trend in installed solar PV prices in Arizona. In addition, the size of the annual tranches of solar PV capacity in the RUCO proposal are far smaller than the recent pace of annual distributed solar installations in TEP's territory, and thus would represent a substantial reduction in solar deployment in the Tucson area. Finally, implementation of the RPS Credit option in this case, on a temporary basis, may create a new grandfathering issue when the option is re-visited in Phase 2. Creating such an issue is unnecessary, given that, by the time an RPS credit can be implemented for TEP, the Commission is likely to have already provided guidance in other dockets on the long-term viability and structure of any RPS Credit option.

If the Commission decides to implement the RPS Credit option for TEP in this Phase 1 case, I propose an alternative schedule of declining credits that remedies the problems with RUCO's proposal. However, the primary recommendation of this testimony is that the RPS Credit option should not be adopted now, but should be one of the alternatives that are evaluated carefully in Phase 2 of these consolidated dockets in the full light of the Commission's decision in the Value of DG docket.

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I. INTRODUCTION / QUALIFICATIONS

Q1: Please state for the record your name, position, and business address.

A1: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q2: Have you previously submitted testimony in these consolidated dockets?

A2: Yes. In Docket E-01933A-15-0239, I submitted direct testimony on behalf of the Energy Freedom Coalition of America ("EFCA") addressing Tucson Electric Power's ("TEP") proposals to expand several utility-owned solar programs.

Q3: Please describe your experience and qualifications.

A3: My experience and qualifications are described in my previously-filed direct testimony in Docket E-01933A-15-0239 and in my CV, which is attached as **Exhibit 1** to that testimony.

Q4: On whose behalf are you testifying at this time?

A4: I am testifying on behalf of EFCA.

Q5: What is the purpose of your testimony?

A5: I address the proposal of the Residential Utility Consumers Office ("RUCO") to implement an RPS Credit option that would be available as an alternative to net energy metering ("NEM") for customers who install solar distributed generation ("DG").

II. OVERVIEW OF RUCO'S RPS CREDIT OPTION PROPOSAL

Q6: Please briefly describe RUCO's RPS Credit proposal.

A6: RUCO has presented its RPS credit proposal in its direct and surrebuttal testimony in the instant TEP rate case (Docket No. E-01933A-15-0322),[1] as well as in its exceptions to the Proposed Decision in the recent UNSE Electric ("UNSE") rate case (Docket No. E-04204A-15-0142).[2] RUCO's witness, Mr. Huber, presented the RPS or RES Credit proposal as one of four options intended as alternatives to NEM, the present compensation method for customers who install renewable DG.[3] The RPS Credit option would pay DG customers a rate (the "RPS Credit") for their output that is fixed for 20 years at the time each DG system comes online. RUCO has clarified that this fixed rate could apply either to the DG customer's entire output or just to the power that it exports to the grid.[4] There would be a schedule of declining RPS credits starting at the current retail rate and then decreasing according to a pre-set series of steps; the RPS credit in each successive step would apply to a certain amount of DG capacity. This stepwise-declining structure for the RPS credits would be similar to the schedules of declining solar incentives historically available in a number of states.[5]

Q7: Has the Commission adopted RUCO's RPS Credit proposal for another utility?

A7: Yes. In Decision 75697 in the UNSE rate case, the Commission directed UNSE to offer the RPS Credit option that RUCO proposed in that case. RUCO's proposal will be offered on a short-term, temporary basis until the parties and Commission can "address the long-term feasibility" of this option in the second phase of the UNSE rate case that will address DG issues.[6] The second phase of

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[1] RUCO, Direct Testimony of Lon Huber, at pp. 33-34 and 41-43, also Surrebuttal Testimony of Lon Huber, at pp. 7-12.
[2] Docket No. E-04204A-15-0142, RUCO's Exceptions to Recommended Opinion and Order, at pp. 1-4.
[3] RUCO Huber Direct, at pp. 32-33.
[4] RUCO Huber Surrebuttal, at p. 9.
[5] RUCO Huber Direct, at p. 41-42.
[6] Decision 75697 in Docket No. E-04204A-15-0142, at Finding 179, p. 142.

the UNSE case will follow and will apply to UNSE the Commission's decision on how to assess the benefits and costs of DG, which the Commission is considering in the "Value of DG" case (Docket No. E-00000J-14-0023).[7]

III. THE COMMISSION SHOULD DEFER CONSIDERATION OF RUCO'S RPS CREDIT PROPOSAL TO PHASE 2

Q8: Should the Commission adopt RUCO's RPS Credit proposal in this phase of the TEP rate case?

A8: No. The Commission should defer consideration of RUCO's RPS Credit proposal to Phase 2 of this case, notwithstanding the temporary approval of the option in the recent Phase 1 order in the UNSE case.

Q9: Why shouldn't the RPS Credit option also be adopted for TEP?

A9: RUCO's current proposal for an RPS credit has several flaws that need to be fixed and addressed after the Commission issues its decision in the Value of DG proceeding. As proposed by RUCO, the design of an RPS Credit option will depend directly on the outcome of the Value of DG docket. As a result, RUCO's proposal clearly will need to be reviewed and revised in the Phase 2 cases that will address net metering and DG issues, as the Commission has already provided in the UNSE decision. Thus, the temporary approval of the RUCO proposal is likely to create a grandfathering issue if the concept is revised or scrapped in the Phase 2 cases. There will be a market trial of the RPS Credit option in UNSE's territory; beyond this, there is not a need to approve the RPS Credit Option for other utilities such as TEP. Finally, the likely timing of the Phase 2 case for TEP suggests that the Commission may provide guidance on the final design for (or rejection of) the RPS Credit option in Phase 2 of the UNSE case, even before the "temporary" RPS credit option can be implemented for TEP. In that event, it makes little sense to adopt the RPS Credit option on a temporary basis for TEP.

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[7] *Ibid.* at p. 143.

A. The Value of DG Decision Will Impact the RPS Credit Option.

Q10: Please describe why the Value of DG decision will affect the details of the RUCO RPS Credit proposal, and why the RPS Credit concept will need to be examined and reviewed in Phase 2.

A10: RUCO has suggested that the average RPS Credit across all of the steps or tranches of capacity should be "the long-term value of DG."[8] This value obviously will be a key output of the Commission's adopted Value of DG methodology. As a result, RUCO's RPS Credit structure is not independent of the Value of DG decision.

For example, I do not agree with RUCO's estimate of 7.9 c/kWh as the "long-term value of DG."[9] Based on the description in RUCO's direct testimony, this value includes only a short-term, annual measure of avoided energy costs (the 2016 Market Cost of Comparable Conventional Generation [MCCCG]), plus long-term avoided generation capacity costs. This fails to recognize the long-term energy value from 20-year renewable resources with zero fuel costs. Alternatively, RUCO assumes that TEP's long-term avoided energy costs are the present cost of spot power at the Palo Verde hub, escalated at no more than the inflation rate (2.5% per year) for 20 years.[10] This assumes unrealistically that TEP will obtain all of its marginal power from the spot market over the next 20 years, and that there will be no real increases or spikes in fossil prices or marginal generation costs over this period. RUCO's resulting alleged long-term avoided energy cost of 3.65 cents per kWh is even lower than TEP's single-year 2016 MCCCG. RUCO also does not consider capacity-related avoided transmission and distribution costs or the avoided costs of air emissions including carbon.

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[8] RUCO Huber Surrebuttal, at p. 9, "[t]he basis for each capacity tranche in the RPS Credit Option was formulated to create an average blended rate across all tranches of around 7.7 cents per kWh. This conforms with RUCO's long-term breakeven analysis."

[9] RUCO Huber Direct, at pp. 37-38.

[10] For example, both TEP's *2014 Integrated Resource Plan* (at p. 298) and its March 1, 2016 *Preliminary 2016 Integrated Resource Plan* (at p. 83) show mean long-term Palo Verde price escalation of at least 5% per year. See https://www.tep.com/doc/planning/2016-TEP-IRP.pdf.

Accordingly, I disagree that RUCO's sketchy calculation includes even "the major categories of benefits,"[11] as it asserts. RUCO's direct testimony admits that there is a high degree of uncertainty around this value, in part due to a lack of "official Commission position or guidance on this issue."[12] Such guidance is hopefully precisely what the Value of DG decision will provide.

B. RUCO's RPS Credit Steps Are Not Cost-based.

Q11: Are there issues with certain details of RUCO's RPS concept that need to be reviewed?

A11: Yes. I address these details below, although they also should be reviewed in more detail in the coming Phase 2 cases. First, RUCO's proposal uses the current retail rate as the starting point for the declining schedule of RPS Credits. It is important to recognize that a bill credit for DG output that is fixed for 20 years at today's retail rate already represents a substantial reduction in compensation for DG customers, because, under NEM today, bill savings escalate over time as retail rates increase. For example, **Figure 1** below shows that, if TEP's current residential rate of 11 cents per kWh grows at 2.5% per year, the 20-year levelized retail rate (at a 7.26% discount rate[13]) is 13.3 cents per kWh, which is the 20-year levelized bill savings under NEM. Thus, if the initial step of RUCO's RPS Credit is set at 11 cents per kWh for 20 years, this represents an immediate 17% reduction in expected compensation for solar customers. In addition, the benefits of DG will increase over time as avoided fuel costs increase and as utility costs grow with inflation. This is not fully recognized in RUCO's 7.9 cents per kWh long-term value of DG. These issues will need to be addressed in light of the decision in the Value of DG docket, before a reasonable RPS Credit program can be designed.

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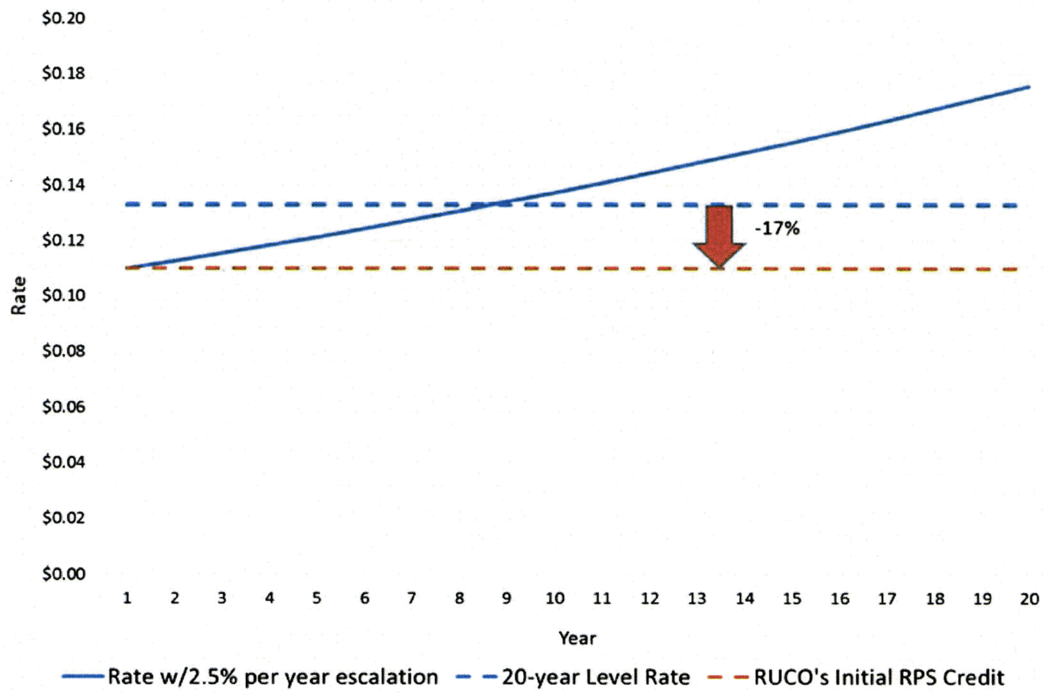
[11] *Ibid.*, at p. 37.
[12] *Ibid.*
[13] Based on TEP's weighted average cost of capital.

Figure 1: Impact of Rate Escalation



Q12: RUCO also suggests that the RPS Credit should decline by 7% between tranches, based on the annual drop in solar costs from 2008-2013.[14] Is this reasonable?

A12: No. In fact, RUCO's actual proposal includes decreases in the bill credits in the initial tranches that are much greater than 7%. As noted above, the starting tranche of $0.11 per kWh is effectively a -17% drop in compensation compared to NEM today. RUCO is also proposing declines of -9.1% and -10.0% in moving to the second and third steps, respectively. The cumulative decreases in NEM compensation in RUCO's first three tranches, compared to today, are, respectively, -17%, -25%, and -32%.

Moreover, the Commission should use the most recent data on solar costs from 2014 and 2015. RUCO cites only data ending in 2013.[15] The more recent data

[14] RUCO Huber Surrebuttal, at p. 10.
[15] *Ibid.*

from 2014 and 2015 shows that the decline in solar costs has slowed significantly in Arizona, compared to the years that RUCO is using. The Lawrence Berkeley National Lab's most recent *Tracking the Sun VII and IX* reports from August 2015 and August 2016 include the results of their extensive survey of the trends in solar prices in 2014 and 2015. LBNL's authoritative price surveys of PV installations are based on data from almost one-half of the 965,000 solar PV systems installed in the U.S. through calendar year 2015.[16] **Table 1** shows this price data from Arizona for 2014 and 2015.

Table 1: *2014 and 2015 Solar PV Installed Price Data for Arizona*[17]

Market Segment	Cost Percentile	Solar PV Costs ($ per watt DC)		
		2014	2015	Change
Residential (< 10 kW)	Median	**3.59**	**3.59**	**No change**
	20%	2.79	2.68	
	80%	4.98	4.40	
Small Commercial (10 kW to 500 kW)	Median	**3.63**	**3.48**	**-4.1%**
	20%	2.91	2.54	
	80%	5.40	5.36	

This data shows no change in median installed prices for residential PV from 2014 to 2015, and a 4% drop for small commercial systems. For the entire U.S., LBNL reports that installed residential PV prices declined by about 5% from 2014 to 2015, based mostly on data from states such as California with more expensive systems.[18] Thus, the RUCO bill credit proposal is based on reductions in the compensation for DG customers that is far greater than the recent trend in cost reductions for solar DG in Arizona. RUCO has not provided any calculations that solar DG will be economic for participating customers in the near future in TEP's territory at RPS credits in the first three tranches that represent decreases in compensation of -17%, -25%, and -32% compared to NEM today. This is the

[16] LBNL, *Tracking the Sun IX* (August 2016), at p. 1. These reports are available at https://emp.lbl.gov/sites/all/files/lbnl-188238_1.pdf and https://emp.lbl.gov/sites/all/files/tracking_the_sun_ix_report.pdf.

[17] LBNL, *Tracking the Sun VIII* (August 2015), data for Figures 19 and 20, and *Tracking the Sun IX* (August 2016), data for Figures 18 and 19.

[18] *Tracking the Sun IX*, at p. 1.

type of issue that will need to be examined in more detail in Phase 2, in order to ensure that any RPS Credit that is adopted provides a realistic path forward for future customers who choose to install solar DG systems.

C. The Sizes of RUCO's Proposed Tranches Are Too Small.

Q13: Do you share the concern that Ms. Kobor expresses in her surrebuttal testimony for Vote Solar that the sizes of RUCO's proposed tranches are too small?

A13: Yes, I do. If the decline in the credit from tranche to tranche is based on the recent trend in year-to-year changes in annual costs, then the size of the tranche should match the recent trend in annual installations, as Ms. Kobor recommends. RUCO's tranches average about 1,300 residential customers per tranche,[19] compared to TEP's recent experience of adding almost 4,000 solar customers per year. If the tranches are too small and if this option is attractive to customers (which is questionable given the significant reductions in compensation that RUCO proposes), the market will drop quickly to the lowest economic tranche, exhaust the limited available capacity, and go bust. This is similar to the experience in solar markets where incentives have been offered for only a limited amount of capacity. The incentives sell out quickly, and installers must deal with periods of boom and bust.

D. EFCA's Recommended RPS Credit Option

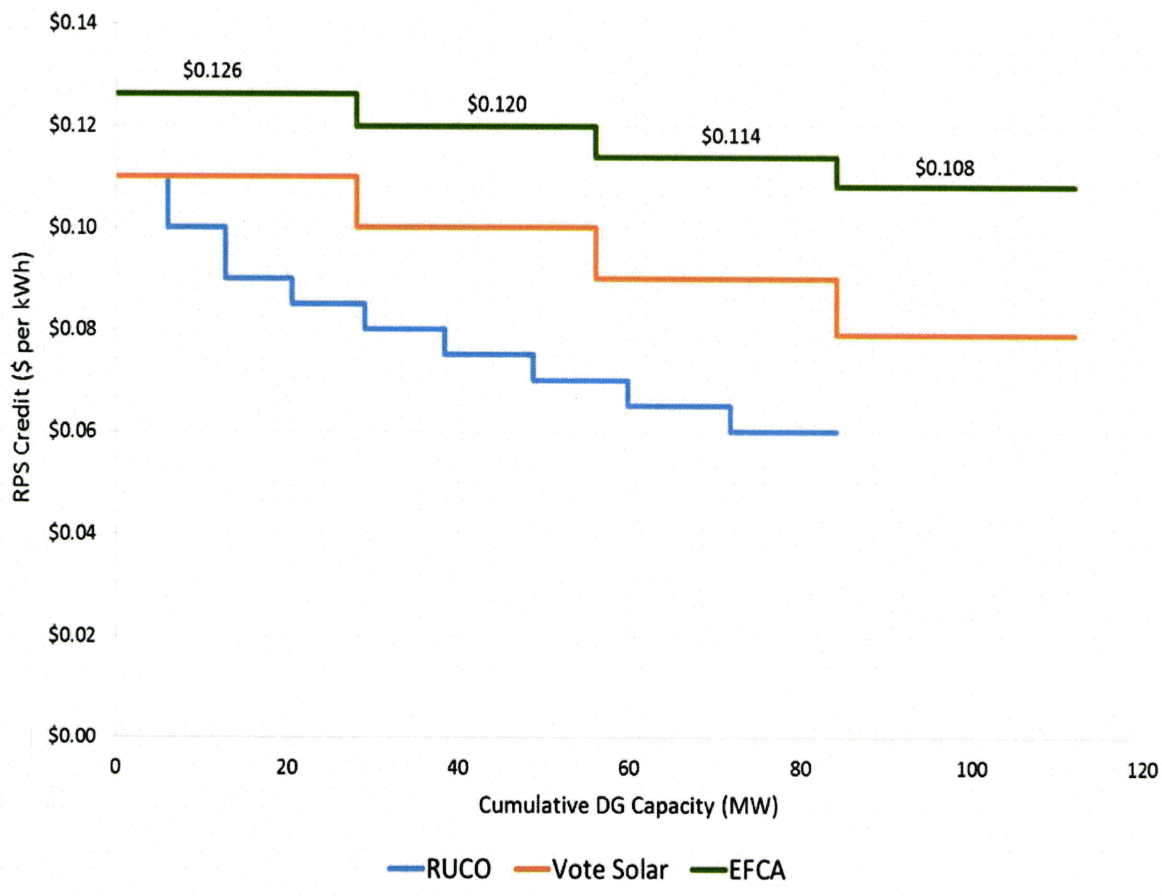
Q14: What would you recommend as the structure for a successful RPS Credit option, if the Commission decides to adopt this option on a temporary, pilot program basis for TEP?

A14: My primary recommendation is that it is most appropriate to explore the details of the RPS Credit alternative in Phase 2. However, if the Commission chooses to

[19] Based on RUCO's average tranche size of 9.4 MW and an average system size of 7.3 kW in the fourth quarter of 2015. See TEP, Tilghman Direct Testimony in Docket E-01933A-15-0239 , at p. 10.

adopt a temporary RPS Credit option here, the initial RPS credit rate should be close enough to compensation under NEM to be reasonable as an option for new solar customers. Thus, I would use 95% of the current 20-year levelized TEP rate (12.6 cents per kWh) as the starting credit, then reduce the credit by 5% in each successive tier. The size of each tier would be 28 MW, the same as recommended by Vote Solar's Ms. Kobor. Again, while I think that this recommended program would be a significant improvement over the RUCO proposal and acceptable on an optional basis, it will continue to be important to explore and refine the details of this program in Phase 2. **Figure 2** below compares the EFCA, Vote Solar, and RUCO proposals for the RPS Credit option.

Figure 2: Proposals for the RPS Credit Option



E. Avoid Grandfathering Issues

Q15: Do you expect that, if the RPS Credit option is adopted in this case for TEP, the Commission will re-evaluate the option in Phase 2 of this case, as it is planning to do for UNSE?

A15: Yes, that would make sense. The Commission clearly stated in the UNSE order that Phase 2 of the UNSE case will re-evaluate both the need for and the details of the RPS Credit option, after the Value of DG decision is issued. EFCA assumes that the same provision would apply if an RPS Credit option is adopted for TEP.

Q16: Does the likelihood that the RPS Credit option will be changed or even scrapped in Phase 2 create grandfathering issues?

A16: Yes, it does. Any adoption now of an RPS Credit program will be on a short-term basis. However, the essence of the program is the ability of customers to select a 20-year RPS credit rate to apply either to the entirety of their DG output or to their exports to the grid. As a result, even a temporary approval of this option will create, in essence, a 20-year pilot program that TEP will have to implement and maintain over a 20-year period (if it is successful), even if the program is quickly terminated as a result of taking a different direction on NEM in Phase 2.

Alternatively, if the RPS Credit is continued as a result of Phase 2, the tranche structure and rate levels for the RPS Credit may be changed in Phase 2. This obviously would create a grandfathering issue with respect to those DG customers who elect the RPS Credit before it is revised in Phase 2. These grandfathering issues can be avoided if the RPS Credit is evaluated on the same basis and at the same time as all of the other Phase 2 proposals.

F. Implementation Timing and Cost Concerns

Q17: Would the implementation of RUCO's RPS Credit option, on a temporary basis after the decision in this phase, involve significant effort and costs for TEP?

A17: The implementation would require a substantial effort, including customer education about the new option, website development to provide public tracking of the tranches, and the re-design of billing systems. I do not have a cost estimate for this work, but it would not be trivial if this program is to be successful as an alternative to NEM.

Q18: What is the expected timing for the review of the RPS Credit Option in Phase 2 of the UNSE case?

A18: Assuming that a Value of DG order is issued this fall, it is my understanding that Phase 2 of the UNSE case would begin immediately thereafter, with a decision in March 2017.[20]

Q19: Is it possible that this Phase 2 decision could be available prior to the implementation of a temporary RPS Credit option for TEP?

A19: Yes. If Phase 1 of this case concludes in December 2016 or January 2017, the implementation of a temporary RPS Credit option would require an additional four months (120 days), that is, until April or May 2017, as was provided in the recent UNSE decision.[21] TEP would have to expend significant effort, and unknown but non-trivial costs, to implement a temporary RPS Credit program that might have been supplanted by other Commission determinations before it is even implemented. This timing argues in favor of not adopting an RPS Credit option for TEP on a temporary basis, but instead reviewing this option for TEP in Phase 2 in light of the preceding Phase 2 decision for UNSE.

[20] Decision No. 75697, at pp. 116-117: "In no case should a final Commission determination of the DG issues in this docket take place later than the March 2017 Open Meeting."
[21] *Ibid.*, at p. 146.

IV. CONCLUSION

Q20: Do you agree that the limited initial trial of the RPS Credit in UNSE service territory which the Commission adopted in Decision No. 75697 is adequate as a limited "proof of concept" to see if RUCO's idea has traction in the DG marketplace?

A20: Yes, I do. The RPS Credit concept has a number of positive features: a long-term credit, the certainty of a fixed credit, and the applicability to either all output or just to exports at the customer's election. Nonetheless, the concept is clearly an alternative to net metering and key details of the RPS Credit option depend directly on the Commission's decisions in the Value of DG docket. As discussed above, there are a number of important details of the RUCO proposal that need to be reviewed and changed, preferably in Phase 2, if the option is to be a reasonable alternative to NEM. Accordingly, the RPS Credit option as proposed by RUCO should not be adopted on an interim basis in this case, without the changes recommended above, and must be further reviewed in Phase 2.

Q21: Does this conclude your prepared supplemental testimony?

A21: Yes, it does.