ARIZONA CORPORATION COMMISSION
Powering Arizona's Future

OPEN MEETING ITEM

0000187405

Executive Director, Ted Vogt

ORIGINAL

Bob Burns
Andy Tobin
Boyd Dunn
Justin Olson

DATE: APRIL 12, 2018

DOCKET NO.: E-01933A-15-0239 AND E-01933A-15-0322

TO ALL PARTIES:

Enclosed please find the recommendation of Chief Administrative Law Judge Jane L. Rodda. The recommendation has been filed in the form of an Opinion and Order on:

TUCSON ELECTRIC POWER COMPANY
(RATES / PHASE 2)

Pursuant to A.A.C. R14-3-110(B), you may file exceptions to the recommendation of the Administrative Law Judge by filing an original and thirteen (13) copies of the exceptions with the Commission's Docket Control at the address listed below by **4:00** p.m. on or before:

APRIL 12, 2018

The enclosed is NOT an order of the Commission, but a recommendation of the Administrative Law Judge to the Commissioners. Consideration of this matter has tentatively been scheduled for the Commission's Open Meeting to be held on:

APRIL 26, 2018

For more information, you may contact Docket Control at (602) 542-3477 or the Hearing Division at (602) 542-4250. For information about the Open Meeting, contact the Executive Director's Office at (602) 542-3931.

Arizona Corporation Commission
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EXECUTIVE DIRECTOR

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On this 12th day of April, 2018, the following document was filed with Docket Control as a Recommended Opinion and Order from the Hearing Division, and copies of the document were mailed on behalf of the Hearing Division to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the filed document to the following who have consented to email service.

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

TOM FORESE – Chairman
BOB BURNS
ANDY TOBIN
BOYD DUNN
JUSTIN OLSON

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 DECISION NO. __________ **OPINION AND ORDER (Phase 2)**

DATES OF PHASE 2 PUBLIC COMMENT:	June 26, 2017, and October 23, 2017
PLACE OF PHASE 2 PUBLIC COMMENT:	Tucson, Arizona
DATES OF PHASE 2 HEARING:	October 24-27 and 30, 2017, and November 2, 2017.
PLACE OF PHASE 2 HEARING:	Tucson, Arizona
ADMINISTRATIVE LAW JUDGE:	Jane L. Rodda[1]
PHASE 2 APPEARANCES:[2]	Mr. Michael W. Patten, SNELL &

[1] Judge Belinda Martin presided at the afternoon portion of the October 23, 2017, Public Comment.

[2] The parties listed made appearances in Phase 2 of the rate case. The following parties made appearances in these dockets during Phase 1 but not in Phase 2: Mr. Thomas Loquvam, PINNACLE WEST CAPITAL CORPORATION LAW DEPARTMENT, on behalf of Arizona Public Service Company; Mr. Scott S. Wakefield, HIENTON & CURRY, PLLC, on behalf of Wal-Mart Stores, Inc. and Sam's West, Inc.; Mr. Lawrence V. Robertson, Jr, of counsel for MUNGER CHADWICK, PLC, on behalf of Noble Americas Energy Solutions, LLC (subsequently known as Calpine Energy Solutions) and Southern Arizona Home Builders Association; Mr. Jeffrey W. Crockett, CROCKETT LAW GROUP, PLLC, on behalf of Tucson Meadows LLC; Mr. Kyle J. Smith, General Attorney, U.S. ARMY LEGAL SERVICES AGENCY, Regulatory Law Office, on behalf of the Department of Defense and all other Federal Executive Agencies; Ms. Camila Alarcon, GAMMAGE & BURNHAM, PLC, and Michelle Van Quathem, LAW OFFICES OF MICHELLE VAN QUATHEM, on behalf of SOLON Corporation; Mr. Kurt Boehm, BOEHM, KURTZ & LOWRY, on behalf of the Kroger Co.; Mr. Charles Wesselhoft, PIMA COUNTY ATTORNEY'S OFFICE, on behalf of Pima County; and Mr. Timothy Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, on behalf of Southwest Energy Efficiency Project, Western Resource Advocates, Arizona Community Action Association, and local counsel for Vote Solar.

WILMER, LLP, and Mr. Bradley S. Carroll, Tucson Electric Power Company, for Tucson Electric Power Company;

Mr. Court S. Rich, ROSE LAW GROUP, PC, for Energy Freedom Coalition of America and The Alliance for Solar Choice;

Mr. Daniel W. Pozefsky, Chief Counsel, and Jordy Fuentes, Staff Attorney for the Residential Utility Consumer Office;

Ms. Meghan H. Grabel and Ms. Kimberly Ruht, OSBORN MALEDON, PA, on behalf of Arizona Investment Council;

Mr. Michael Hiatt, Staff Attorney, Earthjustice, on behalf of Vote Solar;

Mr. Patrick Black and Mr. C. Webb Crockett, FENNEMORE CRAIG, PC on behalf of Freeport Minerals Corporation and Arizonans for Electric Choice and Competition;

Mr. Nicholas J. Enoch, LUBIN & ENOCH, PC, on behalf of International Brotherhood of Electrical Workers Local 1116;

Mr. Keven Koch, *in propria persona*;

Mr. Bruce Plenk, *in propria persona*; and

Ms. Robin Mitchell and Mr. Wesley C. Van Cleve, Staff Attorneys, Arizona Corporation Commission, Legal Division, for the Utilities Division.

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BY THE COMMISSION:

DISCUSSION

I. Background

A. Procedural History

On November 5, 2015, Tucson Electric Power Company ("TEP" or "Company") filed an application for a rate increase ("Rate Case"). The application was based on a "test year" ended June 30, 2015.As part of that application, TEP sought a change to its net metering tariff which would have modified how net metered customers would receive credit for the excess energy generated by their rooftop solar Distributed Generation ("DG") systems. TEP's initial proposal would have established a grandfather date for existing net metered customers of June 1, 2015, and would have required new DG solar customers after June 1, 2015, to take service from TEP under a three-part rate (i.e. mandatory residential demand charges). TEP proposed that the new DG solar customers would pay the retail rate for the energy provided by TEP and would be compensated for any excess energy produced by the DG system at a rate that reflected the current cost of utility-scale solar tied to the distribution grid (then 5.4 cents/kWh)[3]. TEP claimed that its proposed changes to the net metering tariff would mitigate the cost shift between DG customers and non-DG retail customers and would prevent TEP from over-paying for renewable energy.

On July 1, 2015, TEP filed its 2016 Renewable Energy Standard Tariff Implementation Plan ("2016 REST Plan"). In its filing, TEP, *inter alia,* sought to expand its Tucson Owned Rooftop Solar ("TORS") program and proposed a new Residential Community Solar ("RCS") program.[4] On April 6, 2016, the Rate Case was consolidated with TEP's 2016 REST Plan in order that rates associated with the RCS could be addressed in the Rate Case. The Commission issued Decision No. 75815 on November 22, 2016, which addressed issues related to expansion of the TORS program and found that TEP should propose the RCS program in Phase 2 of the Rate Case.[5]

By Procedural Order dated August 22, 2016, issues raised in the Rate Case related to "changes

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[3] See Ex TEP-4 Phase 1 Direct Testimony of David Hutchens at 25.

[4] The TORS program had been proposed as a pilot program in TEP's 2015 REST Implementation Plan. See Decision No. 74884 (December 31, 2014). In its 2016 REST Plan, TEP proposed the RCS program, under which TEP would either build and own, or contract with a third party to build, a 5-Megawatt ("MW") system connected to TEP's distribution system.

[5] Decision No. 75815 at 39.

to net metering and rate design for new DG customers" were deferred to Phase 2, which would follow the conclusion of Docket No. E-00000J-14-0023, *In the Matter of the Commission's Investigation of Value and Cost of Distributed Generation* ("Value of Solar" docket).[6]

In Phase 1 of the Rate Case, intervention was granted to: the Residential Utility Consumer Office ("RUCO"), Pima County, Freeport Minerals Corporation and Arizonans for Electric Choice and Competition (collectively "AECC"), International Brotherhood of Electrical Workers Local 1116 ("IBEW"), Noble Americas Energy Solutions, LLC (subsequently Calpine Energy Solutions), Arizona Investment Council ("AIC"), Vote Solar, Sierra Club, The Alliance for Solar Choice ("TASC"), the Energy Freedom Coalition of America ("EFCA"),[7] Arizona Public Service Company ("APS"), the Arizona Solar Energy Industries Association, the Arizona Utilities Ratepayers Alliance, Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively "Wal-Mart"), the Kroger Co. ("Kroger"), Western Resource Advocates ("WRA"), the Southwest Energy Efficiency Project ("SWEEP"), Arizona Community Action Association ("ACAA"), SOLON Corporation ("SOLON"), Arizona Competitive Power Alliance, the Department of Defense and Federal Executive Agencies ("DOD"), the Southern Arizona Home Builders Association ("SAHBA"), Tucson Meadows, LLC ("TM"), Arizona Solar Deployment Alliance, and the following individuals: Kevin Koch, Bryan Lovitt and Bruce Plenk.

Not all the intervenors participated in Phase 2 of the proceeding. Parties participating in Phase 2 include: TEP, AECC, AIC, IBEW, Kevin Koch, Bruce Plenk, RUCO, TASC/EFCA, Vote Solar, and the Commission's Utilities Division ("Staff").[8]

On January 3, 2017, the Commission issued Decision No. 75859 in the Value of Solar docket. In that Decision, the Commission established the Resource Comparison Proxy ("RCP") methodology to be used in pending electric utility rate cases to determine the appropriate compensation rate for exported DG solar energy. Decision No. 75859 directed that for currently pending electric utility rate

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[6] The Commission had earlier deferred consideration of the same issues in the rate case of TEP's sister company, UNS Electric, Inc. ("UNSE"). *See* Decision No. 75697 (August 19, 2016).

[7] EFCA was granted intervention in the 2016 REST Plan docket which was consolidated with the Rate Case. TASC and EFCA are similar types of organizations representing solar industry stakeholders, and are represented by the same counsel in this proceeding. They filed joint pleadings and sponsored witnesses jointly, and for ease of reference, will be referred to as "TASC/EFCA".

[8] Fresh Produce Association of the Americas ("Fresh Produce") and EFCA were intervenors in the UNS Electric, Inc. ("UNSE") rate case and participated in the combined Phase 2 proceeding.

cases, the utility would provide the underlying data upon which the RCP relies to Staff pursuant to a procedural order to be issued in those rate cases.[9] The Hearing Division was ordered to promptly issue any necessary procedural orders regarding the incorporation of the RCP into the existing proceedings. At the time the Value of Solar Decision was adopted, the following electric utilities had pending rates cases: TEP, UNSE (Docket No. E-04204A-15-0142), APS (Docket Nos. E-01345A-16-0036 and E-01345A-16-0123), Trico Electric Cooperative, Inc. (Docket No. E-01461A-15-0363), Sulphur Springs Valley Electric Cooperative, Inc. (Docket No. E-01575A-15-0312), and Mohave Electric Cooperative Inc. (Docket No. E-01750A-16-0207).

On January 5, 2017, counsel for TEP filed in both this docket, and in the pending UNSE rate case, a Request for a Joint Procedural Conference to discuss procedures and timing for Phase 2 of the TEP and UNSE rate cases.

By Procedural Order dated January 6, 2017, a Procedural Conference to discuss procedures and timing of Phase 2 of the Rate Case was set for January 19, 2017.[10]

The January 19, 2017, procedural conference convened as scheduled with appearances by the TEP and UNSE, TASC/EFCA, AIC, SWEEP, WRA and ACAA, Vote Solar, AECC, Calpine Energy Solutions, SOLON, IBEW, Pima County, TM, AZ Solar Deployment Alliance, Mr. Plenk, SAHBA Fresh Produce, and Staff. The parties proposed a procedural schedule for Phase 2 based on the directives of the Value of Solar Decision and their experience with the pending APS rate case.

On January 24, 2017, the Recommended Opinion and Order for Phase 1 of the TEP Rate Case was docketed.

By Procedural Order dated January 27, 2017, the hearing in Phase 2 of the Rate Case was set to commence on June 28, 2017, and other procedural guidelines established, including a public comment meeting on June 26, 2017, at the Commission's Tucson offices.[11]

On February 2, 2017, TEP filed a Request to Amend Notice Requirements regarding what

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[9] Decision No. 75859 at 177.

[10] Also on January 6, 2017, SOLON filed a Motion to Set Deadline for Production of Interval Data. This Motion was related to issues being considered in Phase 1 of the Rate Case and was ultimately rendered moot given the ultimate findings in Phase 1 of the Rate Case.

[11] Because of the overlap in issues and parties, TEP's Phase 2 Rate Case hearing was set to run concurrently with the Phase 2 Hearing for UNSE, although the matters were not consolidated.

documents would be available for public review. The public notice of the Phase 2 hearing was modified by Procedural Order dated February 3, 2017.

On February 24, 2017, in Decision No. 75975, the Commission approved a rate increase for TEP in Phase 1 of the Rate Case. The Commission approved a settlement agreement that provided a non-fuel base rate increase of $81,500,000 over test year ended June 30, 2015, revenues, for a total non-fuel revenue requirement of $714,022,900. Relevant to the Residential and Small Commercial ("SGS") Classes, the Commission approved four rate options—a standard two-part rate, a two-part Time-of-Use ("TOU") rate, a three-part rate, and a three-part TOU rate. The Commission found that TOU rates should be the default rate for new customers, but that the default status of the TOU rates would not take effect until TEP filed notice that it has completed the necessary revisions to its billing systems, but no later than January 1, 2018. With regard to rates affecting DG customers, the Commission approved RUCO's proposed RPS Credit option and an interim monthly meter charge based on the incremental cost of the bidirectional meter, applicable to new DG connections, of $2.05 for residential customers and $0.35 for SGS customers. The Commission also approved a one-time up-front buy-out option in lieu of the monthly meter charge. However, the Commission also determined that the DG meter fee adopted in Phase 1 would be further evaluated and possibly refined in Phase 2.[12]

On March 17, 2017, TEP filed the Phase 2 Direct Testimony of Carmine A. Tilghmen, Craig A. Jones, and Richard D. Bachmeier.

On April 3, 2017, TEP filed a Notice of Compliance indicating that TEP had the Public Notice of the Phase 2 hearing published in the *Arizona Daily Star*, a newspaper of local circulation, on March 13, 2017; mailed to customers as a bill insert beginning March 1, 2017, and ending March 29, 2017; and placed in the Joel Valdez Main Library in Tucson.

On April 19, 2017, Staff requested an extension of one day to file its Direct Testimony on the RCP, which request was granted by Procedural Order docketed April 20, 2017.

On April 20, 2017, Staff filed the Direct Testimony of Ralph Smith on the RCP.

On April 21, 2017, Staff filed a Notice of Errata to correct an attachment to Ralph Smith's

[12] Decision No. 75975 at 155.

Direct Testimony.

On May 19, 2017, Vote Solar filed the Direct Testimonies of Briana Kobor and Curt Volkman; RUCO filed the Phase 2 Rebuttal Testimony of Lon Huber; TASC/EFCA filed the Phase 2 Direct Testimony of R. Thomas Beach; AIC filed the Phase 2 RCP Direct Testimony of Gary Yaquinto; TEP filed the Rebuttal Testimony of Carmine A. Tillman Regarding RCP; and Staff filed the Phase 2 Rebuttal Testimony of Ralph Smith. On May 23, 2017, Mr. Koch filed his Phase 2 Testimony.

On May 30, 2017, Staff filed a Notice of Settlement Discussions Phase II, and TEP filed a request to modify the procedural schedule by extending the deadline to file testimony from June 5, 2017, to June 12, 2017, to allow the parties to engage in settlement discussions.

By Procedural Order dated May 31, 2017, the procedural schedule was modified to extend the deadline for pre-filed testimony as requested.

Settlement discussions took place at the Commission's offices in Phoenix on June 5, 2017.

On June 7, 2017, Staff filed a Request to Temporarily Suspend and Modify Procedural Schedule to allow settlement discussions that commenced on June 5, 2017, to continue.

On June 8, 2017, TASC/EFCA and Vote Solar filed a Response to Staff's June 7, 2018, Request stating their support for continued settlement discussions, but clarifying the need for additional opportunity to file testimony.

By Procedural Order dated June 8, 2017, the procedural schedule established in the January 27, 2017, Procedural Order, and as modified by the May 31, 2017, Procedural Order, was suspended, except for the public comment session scheduled for June 26, 2017.

Further settlement discussions were held on June 6, 2017, and June 19, 2017.

On June 23, 2017, Staff filed a Request for a Procedural Schedule/Conference. Staff reported that the parties were unable to reach a settlement and requested the establishment of a new procedural schedule for Phase 2. Staff proposed a procedural schedule that allowed time for discovery and took account of Staff's available resources, Staff proposed the following schedule:

August 28, 2017	TEP/UNSE Rebuttal Testimony on all Phase 2 issues
September 29, 2017	Staff/Intervenor Surrebuttal Testimony on all Phase 2 issues
October 13, 2017	TEP/UNSE Rejoinder Testimony

October 13, 2017	Prehearing Conference
October 23, 2017	Hearing Commences

By Procedural Order dated June 23, 2017, a telephonic procedural conference convened on June 26, 2017. The following parties attended: TEP and UNSE, RUCO, AIC, TASC/EFCA, Vote Solar, APS, Fresh Produce, Bruce Plenk, and Staff. Although parties were disappointed in the extended period of time before a hearing could be scheduled, no party objected to Staff's proposed schedule.

A public comment session convened on June 26, 2017, at the Commission's offices in Tucson, Arizona. Twenty-eight members of the public appeared to provide comment in these combined TEP and UNSE Phase 2 proceedings.

By Procedural Order dated July 5, 2017, a hearing was set in Phase 2 of both the TEP and UNSE rate cases. Because of the commonality of parties and witnesses, in the interest of efficiency and economy, the hearing for both TEP and UNSE (collectively the "Companies") was set to proceed concurrently, although the matters were not consolidated.

On August 28, 2017, TEP filed the Phase 2 Rebuttal Testimony of Dallas J. Dukes, Susan Gray, Craig A. Jones, and Richard D. Bachmeier. On September 8, 2017, TEP filed a Notice of Errata to correct several pages of Mr. Bachmeier's Phase 2 Rebuttal Testimony.

On September 29, 2017, AECC filed the Phase 2 Surrebuttal Testimony of Kevin C. Higgins; RUCO filed the Phase 2 Surrebuttal Testimony of Lon Huber; AIC filed the Phase 2 RCP Surrebuttal Testimony of Gary Yaquinto; Vote Solar filed the Surrebuttal Testimonies of Briana Kobor and Curt Volkmann; TASC/EFCA filed the Surrebuttal Testimonies of Brian Warshay and R. Thomas Beach; Staff filed the Phase 2 Surrebuttal Testimony of Ralph C. Smith; Mr. Plenk filed the Surrebuttal Testimony of Louis Woofenden; and Mr. Koch filed his Rebuttal Testimony.

On October 6, 2017, TEP filed a proposed witness schedule that had been circulated among the parties.

On October 10, 2017, APS filed notice that it would not be appearing at the October 13, 2017, pre-hearing conference or be taking an active role in the hearing set to begin October 23, 2017.

On October 13, 2017, TEP filed the Phase 2 Rejoinder Testimony of Dallas J. Dukes, Susan Gray, Craig A. Jones, and Richard D. Bachmeier. Also on October 13, 2017, a pre-hearing conference convened for the purpose of discussing witness scheduling and other procedural matters affecting the upcoming hearing.

On October 16, 2017, Calpine Energy Solutions, LLC filed Notice that it would not be taking an active role in Phase 2 of the proceeding.

On October 18, 2017, Staff filed a Notice of Errata to correct the September 29, 2017, Surrebuttal Testimony of Ralph Smith.

On October 19, 2017, Vote Solar filed a Notice of Errata correcting Ms. Kobor's Surrebuttal Testimony filed on September 29, 2017.

A public comment meeting convened on October 23, 2017, at the Commission's Tucson offices. Sixteen members of the public appeared to provide comment.

The hearing in Phase 2 of the TEP Rate Case convened before an authorized Administrative Law Judge on October 24, 2017, and continued over 6 days, concluding on November 2, 2017. Mr. Dukes, Ms. Gray, Mr. Jones and Mr. Bachmeier testified for TEP, Mr. Higgins testified for AECC, Mr. Koch testified on his own behalf, Mr. Woofenden testified for Mr. Plenk, Mr. Warshay and Mr. Beach testified for TASC/EFCA, Mr. Huber testified for RUCO, Mr. Volkman and Ms. Kobor testified for Vote Solar, Mr. Yaquinto testified for AIC, and Mr. Smith testified for Staff. The testimony of Mr. Simer for Fresh Produce was admitted on stipulation.[13]

Following the hearing, the matter was taken under advisement pending the filing of Closing Briefs.

Initial Briefs were filed on December 4, 2017, by the Companies, Mr. Plenk, TASC/EFCA, Mr. Koch, IBEW, AECC, AIC, RUCO, Vote Solar, and Staff.

Reply Briefs were filed on December 19, 2017 by IBEW, and on December 22, 2017, by the Companies, AECC, TASC/EFCA, RUCO, Vote Solar, IBEW, and Staff[14]

Following the issuance of the Decision in Phase 1 of the Rate Case, the Commission received numerous telephone calls, emails and letters related to Phase 2 issues in addition to the in-person appearances at the Public Comment meetings. Although several commenters supported TEP, the vast

[13] Fresh Produce is a party only to the UNSE Rate Case.
[14] On December 22, 2018, AIC docketed a Notice of Filing indicating it would not be filing a Reply Brief.

majority of commenters expressed support for the rooftop solar industry and for more solar resources in general, and opposed TEP's proposed changes to net metering and the DG rate design.

B. The Company

TEP serves almost 415,000 customers in Pima County, of which approximately 90 percent are residential, 9 percent are commercial and less than 1 percent are industrial/mining.[15] TEP also provides power to Fort Huachuca, a U.S. Army base located in Cochise County. The Company's service territory includes 1,155 square miles. As of June 30, 2015, TEP owned or participated in an overhead electrical Transmission and Distribution system consisting of 616 circuit-miles of 500-kV lines, 1,109 circuit-miles of 345-kV lines, 350 circuit-miles of 138-kV lines, 479 circuit-miles of 46-kV lines, and 2,615 circuit-miles of lower voltage primary lines. TEP also operates 4,380 cable-miles of underground electric distribution lines and 106 electric substations with a total installed transformer capacity of 13,132,404 kilovolt amperes.[16] The Company owns 2,454 MW of generating capacity of which 50 percent is coal fired and 50 percent is gas fired, and owns 42 MW of solar generating capacity at ten different projects throughout the state.[17] As of the test year, TEP had contracted for 221 MW of various solar, wind, and biogas resources in Arizona and New Mexico through 12 separate purchase power agreements ("PPAs").[18]

TEP is a wholly-owned subsidiary of UNS Energy Corporation ("UNS Energy"). UNS Energy was purchased by Fortis, Inc. ("Fortis") in August 2014. Fortis is an investor-owned utility holding company based in St. John's, Newfoundland and Labrador, Canada.[19] UNS Energy is also the parent of UNSE, which provides electric service in Santa Cruz and Mohave Counties. UNSE filed its rate case on May 5, 2015, using a test year ending December 31, 2014. In its rate case, UNSE proposed changes to its Residential and SGS DG rates that included mandatory demand charges and similar changes to its net metering tariff as TEP proposed in its Rate Case.[20]

C. The Value of Solar Decision

[15] Ex TEP-18 (Gray Dir) at 2.
[16] *Id.*
[17] Ex TEP-24 (Sheehan Dir) at 2.
[18] *Id.* at 3.
[19] Ex TEP-10 (Bulkley Dir) at 1.
[20] In Decision No. 75697 (August 19, 2016), the Commission approved new rates for UNSE, but deferred consideration of issues related to DG rate design and net metering to a phase 2 proceeding. Decision No. 75697 at 143.

When they initially filed their rate cases, both TEP and UNSE proposed changes to their net metering tariffs and rooftop solar rate designs for new solar DG customers. Because the Value of Solar docket was active and proceeding concurrently with the Rate Cases, the Commission determined in both rate cases that in the interest of efficiency and uniformity, it was in the public interest to defer consideration of the Companies' proposed changes to net metering and the rate design for residential and small commercial DG customers until after the conclusion of the Value of Solar docket.

On January 3, 2017, in the Value of Solar Decision, the Commission determined that it was time to provide certainty and a path forward to resolve disputes surrounding the integration of DG with utility systems in an economic and fair manner, and adopted methodologies to determine the value of and cost of rooftop DG.[21]

The Value of Solar Decision found that rooftop solar customers are partial requirements customers who export power to the grid, and thus, are a separate class of customers. However, the Decision found that the ratemaking implications of this separate class should be determined in each utility's rate case supported by a fully vetted cost of service analysis.[22]

The Value of Solar Decision made the following determinations:

- "Net metering, and the banking of DG exports associated with net metering, should eventually be eliminated and replaced with a mechanism for the direct purchase by utilities of DG exports. Once a DG customer is subject to a DG export compensation rate determined by one of the DG valuation methodologies adopted by this Decision, there will not be further netting or banking of exported DG kWh for that customer."[23]

- "The value of DG exports should be used to inform compensation rates to be paid to DG customers for their exports."[24]

- "There is a need for a valuation of DG methodology that will provide a gradual transition away from the current net metering model for compensation of DG exports that reflects the actual value of DG."[25]

- "A five year rolling weighted average of a utility's solar PPAs and utility-owned solar generating resources used as a proxy for purposes of valuation of solar DG exports is reasonable if the valuation is re-assessed in each electric utility rate case and the inputs are updated annually and the additional benefits of avoided transmission and distribution capacity and avoided line losses are added into the

[21] Decision No. 75859 at 143.
[22] Decision No. 75859 at 146 and 174.
[23] Decision No. 75859 Findings of Fact ("FOF") 131 at 169.
[24] *Id.* at FOF 132at 170.
[25] *Id.* FOF 133 at 170.

weighted average."[26]

- "The best and most reasonable option available in the record of this proceeding for the valuation of DG is the adoption of both Staff's Avoided Cost methodology, with a short-term forecasting view limited to five years to approximately reflect the time that elapses between utility rate cases, and Staff's Resource Comparison Proxy methodology, with a five-year rolling average (based on projects with in-service dates within the last five years), as modified to account for the added benefits of DG including avoided transmission and distribution capacity and avoided line losses. Adoption of both these alternative methodologies to be used in utility rate cases on a going-forward basis will provide a path for a gradual transition away from the current net metering model to one that better reflects the value of DG."[27]

- "For the Resource Comparison Proxy Methodology with a Five Year Rolling Average (Based on Projects and PPAs with In-Service Dates within the Last Five Years), Staff shall use the spreadsheet described in this Decision to develop a proxy for rooftop solar generation, based on a utility's projects and PPAs with in-service dates within the five years up to and including the test year of the rate case. If projects of recent vintage are not available for the utility, Staff shall use pricing data from available industry sources for grid-scale solar photovoltaics ("PV") projects, with priority given to projects in Arizona to the extent available. The Resource Comparison Proxy spreadsheet described in this Decision shall also calculate the additional benefits of avoided transmission and distribution capacity and avoided line losses and those additional benefits should be added to the Resource Comparison Proxy Methodology analysis."[28]

The Value of Solar Decision established the procedure for the currently pending rate cases pursuant to which the utilities would provide the underlying data upon which the RCP relies to Staff pursuant to a procedural order.[29] Thereafter, within 45 days of Staff's receipt of the underlying data, Staff was to file a request for procedural order setting a procedural schedule for evidentiary hearing.[30] The Commission cautioned that these evidentiary hearings would not be the forum to re-litigate any issue decided in the Value of Solar proceeding.[31]

Thus, the Value of Solar Decision adopted a methodology for determining the appropriate level of compensation to be paid to rooftop solar customers for their exported energy, and declined to use it for determining a monetary value of the energy a DG customer consumes on site.[32] Specifically related to the currently pending rate cases, the Commission found that the RCP methodology should be used, with a reduction in the compensation rate not to exceed 10 percent annually, in order to provide for a

[26] *Id.* FOF 141 at 170-71.
[27] *Id.* FOF 144 at 171.
[28] *Id.* FOF 146 at 171-72.
[29] *Id.* FOF 147 at 172.
[30] *Id.* FOF 154 at 173.
[31] *Id.* FOF 155 at 173.
[32] Decision No. 75859 at 147.

gradual transition to the DG export concept.[33] The Commission stated that it was refraining from commenting on the appropriateness of any particular rate design as part of the Value of Solar proceeding, but was committed to modifying residential rate design in a manner that mitigates the recognized cost shift caused by rooftop solar customers' self-consumption.[34] Further, the Commission determined that a DG system that interconnects to a utility's distribution system after a DG export rate is set for that utility shall be placed on the DG export rate effective at the time of the interconnection for a period of ten (10) years.[35]

The Commission also adopted a suggestion from APS to use pricing data from available industry sources for grid-scale solar PV projects in situations where projects of recent vintage are not available for the utility. The Commission explained that the addition would be "useful in analyses of the value of DG in rate cases for smaller utilities with no recent grid-scale projects or PPAs to serve as suitable proxies."[36] The Commission also found:

> In order to be an accurate proxy, however, we do believe that DG should receive credit for costs that it avoids that central station solar (and other central station generation) do not avoid. As a result, the Resource Comparison Proxy we adopt herein will require that avoided transmission, distribution capacity and line losses be considered in the analysis. In order for the comparison between central station solar and DG to be meaningful and accurate, these key differences must be addressed and included in the Resource Comparison Proxy analysis that will occur in the rate case.[37]

The Commission found that in future rate cases, the Commission

> "may use either the Avoided Cost Methodology or Resource Comparison Proxy Methodology or a combination of both in determining the formula for setting the value of DG. The formula setting the assumptions and weighting of the two methodologies is to be determined in each utility's individual rate case or separate rate design phase. The formula should only be changed within a rate case to allow parties an opportunity to scrutinize the assumptions and weighting of the methodologies. However, once the formula has been set, the inputs to the formula should be updated annually to provide for more measured adjustments. We believe that this will reduce

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[33] Decision No. 75859 at 148. The Commission stated that the "Resource Comparison Proxy is the appropriate valuation methodology to utilize for pending electric utility rate cases because doing so will afford parties the necessary time to further develop the implementation parameters of Staff's alternative five-year Avoided Cost methodology. Once a five-year Avoided Cost methodology is finalized, the Commission will have the flexibility to utilize either the Avoided Cost methodology or Resource Comparison Proxy methodology (or a combination of both) in setting a formula for setting the DG export rate in subsequently filed electric utility rate cases for use in annual updates to the export rate."

[34] *Id.* FOF 163 at 175-76.

[35] *Id.* FOF 162 at 175.

[36] Decision No. 75859 at 152.

[37] *Id.* at 15 and *see also* p 153.

the risk of dramatic changes in customers and the solar industry and is consistent with our interest in rate gradualism."[38]

D. The Companies' Requests

In Phase 2 of their Rate Cases TEP and UNSE request that the Commission approve the following:

1. The proposed Residential and SGS DG rate designs for both TEP and UNSE as set forth in their Phase 2 Rejoinder testimony;

2. The monthly incremental DG meter charges of $3.50 (Residential) and $5.62 (SGS) for TEP and $3.00 (Residential) and $4.60 (SGS) for UNSE;

3. A DG Energy export rate of 10.7 cents per kWh for both Companies to be reset on July 1, 2018, to 9.63 cents per kWh for TEP and to 9.2 cents per kWh for UNSE;

4. The RCP Plan of Administration with the Companies' proposed revisions;

5. The TEP Residential Community Solar program as proposed by TEP with a rate of $19 per kW-DC.

6. The modification to TEP's Bright Tucson Tariff, reducing the Green Pricing premium to 1 cent per kWh;

7. UNSE's proposed modification to the Medium General Service ("MGS") tariff to include a seasonal agriculture provision and related authorization to modify the PPFAC to include an Agricultural Adjustment; and

8. An effective date of the new rates as of the date of the Phase 2 Decision or as soon as practical thereafter.

The Companies, Staff, and RUCO are in general agreement on the rate design for new solar DG customers, but have varying positions on the appropriate DG export rate. These parties also agree on the RCS Program and the modifications to TEP's Bright Tucson Tariff. AIC and IBEW support the Companies' positions.

Vote Solar and TASC/EFCA oppose the proposed rate design for new solar DG customers and argue for a higher export rate. Mr. Plenk and Mr. Koch also argue against some of the Companies'

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[38] *Id.* at 153-4.

proposed rate design changes.

AECC participated in Phase 2 of these proceedings to advocate for the recovery of any above-market costs associated with the RCP from the rate classes that are affected by the rate scheme.

II. Positions of the Parties

A. TEP

1. Class Cost of Service Study ("CCOSS").

TEP updated its CCOSS to reflect the final revenue requirement and rate design approved in its Phase 1 proceeding, and then modified the CCOSS to create a separate partial requirements class for Residential and SGS DG customers. In preparing the CCOSS, the Company states that it used the same fixed costs for the system based on the most recent rate case, with necessary adjustments to match the Phase 1 order.[39] TEP states that the fixed costs were then allocated using the average and excess allocation methodology for production costs and the minimum system customer costs and class Non-Coincident Peak ("NCP") for demand related delivery costs. TEP explains that the DG CCOSS is identical to that for non-DG customers except for the NCP and coincident peak ("CP") determinations. In TEP's CCOSS the DG Class NCP is based on the maximum DG Class's use of the distribution system for <u>either</u> consumption <u>or</u> export.[40] TEP argues that using both import and export capacity requirements is essential for a partial requirements customer to incorporate the appropriate maximum burden they place on the system.[41]

According to TEP's CCOSS, the allocated revenue requirement for the residential DG class is $100.40 per customer (as opposed to $87.37 for the residential non-DG full requirements class).[42] The Company asserts that its cost allocation approach understates the actual cost of serving the DG customer class because it does not directly assign increased costs associated with the additional meter, DG specific equipment, additional customer service group dedicated to rooftop solar, or the specific portion of the renewables personnel dedicated to promotion and compliance needs associated with distributed generation.[43] TEP argues these costs should be directly assigned to the DG class because

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[39] Ex TEP/UNSE-P2-9 (Jones Dir) at 5.
[40] Ex TEP/UNSE-P2-9 (Jones Dir) at 4.
[41] TEP Opening Brief at 11; *citing* Ex TEP/UNSE-P2-9 (Jones Dir) at 4.
[42] Ex TEP/UNSE-P2-9 (Jones Dir) at 10.
[43] TEP Opening Brief at 12.

they are a direct result of establishing and maintaining services for these customer and could otherwise be avoided, but for the existence of the DG class.

TEP argues that in the interest of gradualism, it has proposed fixed cost revenue recovery from the new DG customers that is well below their allocated fixed costs. TEP states that under current rate design and net metering, the rate of return for residential DG customers is negative 15.36 percent because 80-90 percent of the fixed costs incurred to serve a typical residential customer are recovered in volumetric rates, and because DG customers avoid paying most of the volumetrically recovered fixed costs due to on-site consumption and kWh banking under net metering.[44] Under its proposed rates, TEP expects to recover $56 in fixed cost revenue from the average customer who installs DG.[45] TEP claims that even under its proposed rates, the rate of return for the residential DG class will remain negative, and the SGS DG class would yield a rate of return lower than the SGS class as a whole.[46]

TEP argues that Vote Solar's and TASC/EFCA's claims that the Company's proposed DG rate design is not sufficiently gradual in mitigating the cost shift are unfounded because TEP's proposed fixed cost recovery of approximately $56 per month from an average DG customer is less than Vote Solar's DG cost allocation of $58. Further, TEP notes that TASC/EFCA's claim that the costs allocated to TEP residential DG customers should be $83 is also greater than the $56 that the Company is proposing to recover.[47]

TEP asserts that its CCOSS comports with standard principles of cost of service allocation.[48] TEP argues that Vote Solar's and TASC/EFCA's assertions that distribution costs should be allocated on the delivered energy demand to DG customers (not on the export energy demand) ignore basic cost of service principles,[49] and that ignoring the export loads in determining the allocation is poor practice, especially when these exports create additional burdens on the system.[50] TEP states that because DG customers' maximum NCP demand on the distribution system is at the time of their maximum exported

[44] Ex TEP/UNSE-P2-9 (Jones Dir) at 12.
[45] TEP Opening Brief at 13-14.
[46] According to TEP, under its proposed two-part DG TOU Rate, it would realize a negative 1.12 percent rate of return compared to a return of positive 3.13 percent on the residential class as a whole. *Id.* at 14.
[47] *Id. citing* Ex TEP/UNSE-P2-6 (Duke Dir.) at 9-10; Ex TEP/UNSE-P2-17 (Vote Solar Schedule G-6-1); Ex. TASC/EFCA-P2-4 (Beach Dir) at 15 (Table 2).
[48] TEP Reply Brief at 4.
[49] *Id.* at 3.
[50] TEP Reply Brief at 3; Ex TEP/UNSE-P2-11 (Jones RJ) at 8; Ex TEP/UNSE-P2-8 (Grey RJ) at 2-3.

deliveries, the maximum NCP for DG customers is not the same as full-requirements customers.

In response to claims that TEP should have used actual hourly usage data from solar customers, the Company states that it "used the same data and billing determinants and followed the same cost allocation principles and methodologies as used in Phase 1" [51] TEP states:

> The Companies' analysis reflects common utility practices, relies on actual customer data and applies standard analysis of load research data to develop hourly load curves in the same way for all other classes of service in the Company's CCOSS. The data is either based on actual metered data for the population or based on a statistically valid sample of the data for the customer class. The same is true for solar DG output, which was modeled from a statistically valid sample of DG installations with the sample size representing between 50 and 82 percent of the sample population as measured from available data.[52]

Finally, with respect to TASC/EFCA's arguments that the CCOSS cost allocation will result in double recovery of revenues from DG customers, the Company states that it allocated distribution costs only based on export demand and did not allocate any additional distribution costs to DG customers based on load demand.[53]

2. Rate Design

In its Rejoinder Testimony, TEP accepted two rate options proposed by Staff for new residential and SGS DG customers: a two-part TOU rate that includes a Grid Access Charge ("GAC") ("DG TOU Rate"), and a three-part TOU rate that includes a demand element ("DG Demand TOU Rate").[54] TEP states that the two rates are designed to recover approximately the same amount of fixed cost revenue from a typical new DG customer. The Company states that the basic service charge, energy delivery charges, and demand charges in the Demand TOU Rate are similar to the Company's current corresponding Demand TOU rate tariff for full-requirements service. The differences in the current full requirements Demand TOU rate and the newly proposed DG Demand TOU Rate are: (1) a 5kW tier level for the DG Demand TOU Rate compared to a 7kW tier for the full-requirements non-DG customer; and (2) a DG meter charge. The two-part DG TOU Rate would have the same basic service charge as the non-DG TOU rate, but would differ by having: (1) a single tier for the volumetric

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[51] TEP Reply Brief at 4; Ex TEP/UNSE-P2-10 (Jones Reb) at 12-13.
[52] TEP Reply Brief at 4 (citations omitted).
[53] *Id.* at 4.
[54] *See* Ex TEP/UNSE-P2-14 (Bachmeier Rejoinder) at 6-19.

component of the rate; (2) a GAC; and (3) a DG meter charge.

TEP proposed DG rates for new residential and SGS DG customers as follow:

Residential Two-Part TOU DG	**TEP/Staff/RUCO Recommended Rates**
Basic Service Charge	$10.00
DG Meter Charge	$3.50
Energy Delivery Service Charge ($/kWh)	$0.07435
DG Grid Access Charges ($/kW-DC)	$2.50
Base Power Charges ($/kWh)	
Summer On-Peak[55]	$0.066567
Summer Off-Peak	$0.026332
Winter On-Peak[56]	$0.032565
Winter Off-Peak	$0.025651

Residential Three-part TOU DG	**TEP/Staff/RUCO Recommended Rates**
Basic Service Charge	$10.00
DG Meter Charge	$3.50
Energy Delivery Service Charge ($/kWh)	$0.033988
Demand Charges ($/kW) - 1st 5 kW	$8.85
Demand Charges ($/kW) – greater than 5kW	$12.85
Base Power Charges ($/kWh)	
Summer On-Peak	$0.066567
Summer Off-Peak	$0.026332
Winter On-Peak	$0.032565
Winter Off-Peak	$0.025651

[55] The summer months are May through September; the summer on-peak period is 3:00 p.m. to 7:00 p.m. Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

[56] The winter months are October through April; the winter on-peak hours are 5:00 a.m. to 9:00 a.m. and 6:00 p.m. to 9:00 p.m. Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

SGS Two-Part TOU DG	TEP/Staff/RUCO Recommended Rates
Basic Service Charge	$22.00
DG Meter Charge	$5.62
Energy Delivery Service Charge ($/kWh)- Summer	$0.052483
Energy Delivery Service Charge ($/kWh) - Winter	$0.08130
DG Grid Access Charge ($/kW-DC)	$2.50
Base Power Charges ($/kWh)	
Summer – On-Peak	$0.071322
Summer – Off-Peak	$0.025609
Winter – On-Peak	$0.038010
Winter – Off-Peak	$0.025651

SGS Three-Part TOU DG	TEP/Staff/RUCO Recommended Rates
Basic Service Charge	$22.00
DG Meter Charge	$5.62
Energy Delivery Service Charge ($/kWh) - Summer	$0.09191
Energy Delivery Service Charge ($/kWh) - Winter	$0.08130
Demand Charge ($/kW) – 1st 5 kW	$9.95
Demand Charge ($/kW) – greater than 5kW	$13.95
Base Power Charges ($/kWh)	
Summer On-Peak	$0.071322
Summer Off-Peak	$0.025609
Winter On-Peak	$0.038010
Winter Off-Peak	$0.025651

a) Grid Access Charge

TEP designed its proposed GAC to collect some of the fixed costs related to generation, transmission, and distribution that the Company incurs to serve DG customers, but which would otherwise be unrecovered due to the use of volumetric rate design.[57] TEP explains that under the proposed DG Demand TOU Rate, a GAC is not necessary because the demand component mitigates the fixed cost under-recovery.

TEP has agreed to Staff's recommended GAC of $2.50 per kW-DC. TEP asserts that the proposed GAC provides relative parity between the DG TOU Rate option and DG TOU Demand Rate option.[58] The Company argues that without the GACs, the two rate options would not be acceptably comparable, and new DG customers would not even consider the three-part DG TOU Demand Rate option.[59]

TEP asserts that the opposition to the GAC because it is too high and will over-recover the fixed cost of service from DG customers assumes that the CCOSS over-allocates costs to the new DG customer classes and that the proposed rate options collect more fixed costs revenues than allocated under the CCOSS. TEP argues that even if one accepts Vote Solar's or TASC/EFCA's approach to cost of service, the proposed DG rate options do not collect more fixed costs revenue than allocated under the CCOSS to the new DG class.[60]

In addition, TEP argues that Vote Solar's position that DG customers should have the same rate options as non-DG customers (i.e., access to a non-TOU option) is contrary to the Commission's finding that DG customers are a separate customer class. The Company argues that it structured the DG rate options to provide a gradual migration of the fixed cost shift.[61] TEP notes that new DG customers under the APS rate case settlement are excluded from non-TOU two-part rates.[62]

The Company argues that claims that GACs cannot be imposed because they do not follow the procedural requirements for a new DG charge under the Net Metering Rules, misconstrue those rules. The Company argues that the GAC is not a stand-alone charge, but is an element of a rate option

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[57] TEP Opening Brief at 8.

[58] *See* Ex TEP/UNSE-P2-14 (Bachmeier Rejoinder) Tables 1 through 8. For example, TEP's analysis shows that a new Medium sized TEP residential DG customer, the two-part DG TOU Rate would result in an average monthly bill of $34.01, a $0.0736/kWh "offset rate", and a simple payback period of 8.9 years. (Bachmeier Rejoinder Table 1); for the same customer on the three-part DG TOU Demand Rate, would see an average monthly bill of $36.12, a $0.0688/kW "offset rate" and a simple payback period of 9.3 years. (Bachmeier Table 2).

[59] TEP Opening Brief at 9.

[60] TEP Reply Brief at 5; *see* Vote Solar Opening Brief at 14.

[61] TEP Reply Brief at 5.

[62] TEP Reply Brief at 5; *see* Decision No. 76295 (August 18, 2017).

designed to recover fixed costs allocated to a new customer class through a CCOSS. They argue that there is nothing improper or discriminatory about a rate option designed to meet a CCOSS for a customer class even if the rate option is different than another customer class. The Company argues that DG customers are dependent on the grid and should bear an equitable share of the fixed costs rather than shift costs to non-DG customers. They claim that the access charge begins to accomplish the goal of the Value of Solar Decision for those customers who opt for the two-part rate.

The Company argues that those parties who contend that new DG customers should not be assessed a GAC because a similar charge is not assessed on other power generators are assuming that "DG generators are identical to other generators from a cost of service perspective."[63] TEP asserts that the solar rooftop generators use the grid entirely differently than wholesale generators, and that "[i]f TASC/EFCA is claiming that DG customers should be treated the same as other partial requirements service ("PRS") customers, the rates for other PRS customers includes (sic) *mandatory* demand charges – there is no two-part rate option."[64] The Company states that it understands that it should not limit service to new residential DG customers to mandatory three-part rates with a demand rate element, and thus, they also offer a two-part TOU rate that includes an element that is intended to reduce the cost shift caused by DG customers.

The Company states that it does not support Mr. Koch's proposal that the GAC be based on a kWh production basis because the record does not contain sufficient information to design such a charge, and the Company is concerned that the billing determinants and customer impacts would be much more variable and provide less certainty to customers.[65]

TEP notes that RUCO has offered two other rate design options – the RPS Credit Option that was approved in the Phase 1 proceedings, and the "Advanced DG Experimental Rate." The Company states that no customer has chosen the RPS Credit Option, and asserts that RUCO's other option, the "advanced DG Experimental Rate," has not been sufficiently detailed in the record to be approved at this time.[66]

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[63] TEP Reply Brief at 6; citing TASC/EFCA Opening Brief at 4.
[64] See TEP Rider-11 Partial Requirements Service (PRS); TEP Reply Brief at 6. (Emphasis in original.)
[65] TEP Reply Brief at 6-7.
[66] TEP Reply Brief at 7.

b) **DG Meter Charge**.

In Phase 1 of the Rate Case, the Commission approved an incremental meter charge of $2.05 for new DG residential customers and $0.35 for new DG SGS customers.[67] In Phase 2, TEP proposes a monthly DG meter charge of $3.50 for residential customers and $5.32 for SGS customers. TEP argues that these charges are "well below" what the CCOSS supports and are an example of gradualism in mitigating the DG cost shift.[68]

TEP argues that because the incremental charge applies only to new DG customers and new DG installations (not to existing meters with embedded costs), the marginal cost data presented in Phase 1 of the proceeding provides the appropriate basis for the incremental bidirectional meter charge.[69]

The Company asserts that the intent of the meter charge is to recover the incremental costs associated with the more expensive bidirectional meter needed to provide service to DG customers. Thus, TEP claims that the incremental cost associated with the new installation is the marginal cost of the new meter less the embedded cost of the old standard meter. It submits that the record shows that the marginal costs for new bidirectional meters of $8.62 and $9.13 per month for Residential and SGS customers of TEP and $9.54 and $12.60 per month for Residential and SGS customers of UNSE.[70] TEP notes that the embedded cost include both standard meters and higher cost bidirectional meters that had already been deployed to DG customers. Thus, the Company states that the embedded cost of a standard meter that is being replaced for new DG customers is lower than shown by the CCOSS, which would support a higher incremental charge than that being proposed by the Company and Staff.[71]

The Company opposes any further use of a one-time upfront DG meter charge in lieu of the standard monthly charge because: (1) the up-front buy-out amounts adopted in Phase 1 were based on embedded cost data which blends all vintage meters and is not consistent with actual marginal costs being incurred for the new meters; and (2) it would exacerbate the fixed cost shift because the upfront

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[67] These charges were intended to cover the incremental cost of the bidirectional meter needed to serve a DG system over the cost of the non-DG customer meter. The Commission indicated that it would review these charges in Phase 2 of the proceeding. Decision No.75975 at 155.

[68] TEP Opening Brief at 9; TEP Reply Brief at 7.

[69] Ex TEP/UNSE P-2-9 (Jones Dir) at 15.

[70] Ex TEP/UNSE-P2-9 (Jones Dir) at 15.

[71] TEP/UNSE Reply Brief at 8.

fee makes no allowance for certain on-going costs (e.g., meter testing, additional trip fee, potential monthly cellular fees, fixed network upgrades, meter repairs or replacements and an increased use in general metering infrastructure) which would then be picked up by other customers.[72] TEP argues that the incremental DG meter charge is based on the same rate-making principles that underlie the basic service charge, and there is no rationale for administering the DG meter fee differently than the basic service charge.[73]

TEP argues that those parties that support a one-time upfront DG meter charge have not disputed that the upfront charge does not cover many costs of the DG meter, which would then be passed on to other customers. The Company argues that should the Commission adopt an upfront DG meter charge option, the charge should be higher than proposed, and the Commission should clarify that the DG customer is responsible for the repair and replacement of any DG meter.[74]

3. Resource Comparison Proxy Rate

TEP proposed an initial combined DG export rate of 9.73 cents per kWh for both Companies.[75] TEP's proposed RCP rate reflects the costs of both PPAs and utility-owned PV facilities for both TEP and UNSE that were put in place and began operating during the five-year period of January 1, 2012, through December 31, 2016.[76]

TEP states, however, that it would not oppose either of the following two options:

1. Adopt Staff's initial combined RCP of 10.7 cents per kWh for both TEP and UNSE, and:
    a. Reset the RCP on July 1, 2018, to 9.63 cents per kWh for TEP, which is a 10 percent reduction.
    b. Reset the RCP on July 1, 2018, to 9.20 cents per kWh for UNSE, which is

[72] TEP Opening Brief at 10.
[73] TEP argues that should the Commission decide to allow for an upfront payment for the incremental cost of the bidirectional DG meter, the cost should reflect the cost of the meter and installation, as well as the cost of meter repairs, meter reading, etc., that can be expected during the life of the meter. TEP argues that any one-time upfront payment should be adjusted to an amount no less than $225 for residential customers and $315 for SGS customers. Furthermore, TEP states that if an upfront payment is allowed, the Commission should make clear that the DG customer would be subject to paying the cost of any necessary meter replacement during the life of the rooftop system. TEP Opening Brief at 10-11. See Tr. at 1081, Vote Solar witness Kobor agreeing it would be appropriate to send the customer another bill for a new meter.
[74] TEP/UNSE Reply Brief at 9.
[75] TEP Opening Brief at 15.
[76] Ex TEP/UNSE-P2-6 (Dukes RJ) at 8; Ex TEP/UNSE-P2-2 and P2-3 (Tilghman RCP Reb) at 2.

equivalent to the weighted average retail rate of the Residential and SGS classes; or

2. Adopt the Companies' and RUCO's initial combined RCP of 9.73 cents, and:
    a. Reset the RCP 12 months after the decision date of Phase 2 to a combined rate of 8.76 cents.

Disagreements among the parties concerning the RCP calculation involved: (1) determining the appropriate five-year period underlying the RCP methodology; (2) whether a transmission and distribution ("T&D") adder is appropriate; (3) the appropriate line loss adjustment; and (4) the timing and amount of the first reset of the RCP export rate.

TEP argues that the initial DG export rate should be a single, blended rate for both TEP and UNSE.[77] TEP believes that using a combined RCP rate for both companies is in the public interest because: (1) the RCP should provide a timely, reliable, and objective wholesale market proxy to which a utility has access in order to determine a basis for exported energy, and TEP and UNSE have access to, and transact within, the same market; (2) the Companies are operated as a single balancing authority, with TEP providing control area services for UNSE; (3) the Companies have interconnected points of operations and can take advantage of shared facilities; and (4) the Companies utilize shared resources, such as personnel in the renewable department, wholesale marketing, control area, accounting and management.[78] In addition, TEP states that using a blended RCP rate comports with the Value of Solar Decision which states that "[i]f projects of recent vintage are not available for the utility, Staff shall use pricing data available from industry sources for grid-scale solar PV projects, with priority given to projects in Arizona to the extent available."[79] TEP states that this directive is particularly pertinent to UNSE as it is much smaller than TEP or APS, and it is more likely that smaller utilities would have "gaps" over a five-year period that should be filled with other available pricing data. TEP argues that using an affiliate's pricing data is a conservative approach to meeting the directive and moots the issue of how to fill in proxy years that do not have a specific project for that year.[80]

[77] The Companies state that no party has vehemently opposed the single rate concept, and only Staff continues to propose separate RCP rates, while stating that it does not oppose a single combined rate. TEP/UNSE Reply Brief at 9.
[78] TEP Opening Brief at 19.
[79] Decision No. 75859 at 172 *cited in* TEP Opening Brief at 19.
[80] TEP Opening Brief at 19; TEP Reply Brief at 9.

Moreover, TEP and UNSE assert that, disregarding the Basic Service Charges, the average retail rate for UNSE is currently 9.16 cents per kWh which is 15 percent lower than TEP's proposed RCP rate of 10.78 cents per kWh. They note, however, that Staff recommends an RCP rate of 12.8 cents per kWh for UNSE which is 22 percent higher than the 10.5 cents per kWh RCP rate that Staff recommends for TEP. TEP and UNSE note that the recommended stand-alone rate for UNSE of 12.8 cents per kWh is 3.6 cents, or 40 percent, higher than the UNSE retail rate. The Companies contend that it does not make sense that the value of a kWh produced by a DG solar system would be 40 percent higher than a kWh supplied by the UNSE system. The Companies argue that imposing a 40 percent premium above retail rates as compensation for excess rooftop solar generation intensifies the cross subsidization of the rooftop solar customers by the non-DG customers, and that a single blended RCP rate would help mitigate the cost shift as intended by the Value of Solar Decision.

a) <u>Five-Year Rolling Average</u>

TEP argues that the DG export rate should be based on recent information, and that it is not in the public interest to strictly adhere to a test year end point limitation that is contradicted by numerous other statements in, and the overall intent of, the Value of Solar Decision.[81] TEP argues that "[s]omething that is intended to be a reasonable market proxy based on the 'five most recent years' should not include market information that is eight years old."[82] TEP notes that the Commission stated that the RCP Rate is a reasonable proxy if it is reassessed in every rate case "and the inputs are updated annually."[83] Thus, TEP asserts, the Commission evidently believed that using current market data is critical if the RCP rate is going to be a reasonable market proxy. The Company argues that the delays in the Phase 2 proceedings exacerbate the effects of adhering to the test-year end point for both TEP and UNSE.

The Companies note that using the period 2012-2016 to calculate the RCP rate for UNSE yields 7.49 cents per kwh, and the significant difference between this and Staff's recommended rate, would mean the single rate results in a more gradual, reasonable approach for UNSE. They state that the 10.7, cents or the 9.73, cents are still above the average retail rate for UNSE, and arguably provides more

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[81] TEP Opening Brief at 16-17.
[82] *Id.* at 17.
[83] Decision No. 75859 FoF 141 at 170.

benefit to new DG customers than net metering.

b) T&D and Line Loss Adders

TEP asserts that any T&D adder would be speculative and should not be included in the DG export rate. TEP acknowledges that the Value of Solar Decision provides that "avoided transmission, distribution capacity and line losses be considered" in setting the DG export rate under the RCP methodology, but argues that because any increase to the DG export rate based on a T&D adder is passed on to customers, any such adder should be known and measurable and not speculative.[84] The Company asserts that it has not identified any transmission or distribution capacity that will be avoided by the adoption of new DG; and notes that Staff's witness searched hard for whether it could be reliably quantified, and also concluded there is no reliable amount of T&D savings.[85] TEP asserts that neither Vote Solar nor TASC/EFCA has identified any specific avoided costs, but attempt to estimate costs that might be avoided in the future. TEP argues such speculation does not yield known and measurable costs, and that the estimation methodologies utilized rely on unproven assumptions that are prone to subjective interpretation.[86]

TEP also argues that the because a higher line loss rate as advocated by Vote Solar and TASC/EFCA translates to a higher RCP rate and increases the costs paid by non-DG customers, the line loss factor should be a conservative calculation and should not reflect elements that do not actually exist.[87] The Company argues that neither Vote Solar nor TASC/EFCA have addressed why a line loss factor higher than the 3.53 percent proposed by the Companies, Staff, and RUCO should be adopted.[88]

c) Timing of RCP Reset

TEP argues that the Commission should approve the first reset of the DG export rate in this proceeding because the RCP information for the period 2013-2017 is known and measurable and the five-year rolling average can be calculated now.[89] According to TEP and UNSE, the RCP rate based on the five-year average of the Companies' grid-scale solar PV facilities and PPAs for the five years

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[84] TEP Opening Brief at 20.
[85] Tr. at 1173-1174.
[86] TEP Opening Brief at 22.
[87] TEP Reply Brief at 10.
[88] TEP Reply Brief at 10.
[89] *Id.* at 23.

ending December 31, 2017, would be \$0.0817 per kWh.[90] TEP proposes that:

1. If the initial combined RCP rate be set at 10.7 cents per kWh for both TEP and UNSE, the RCP rate be reset on July 1, 2018, to 9.63 cents for TEP, which is 10 percent less than 10.7 cents, and to 9.20 cents for UNSE, which is equivalent to the weighted average retail rate of the Residential and SGS classes; and
2. If the initial combined RCP rate is set at 9.73 cents for both companies, then the RCP rate should be reset as of twelve months from the date of the Phase 2 Decision, to 8.76 cents per kWh for both TEP and UNSE, with is 10 percent less than 9.73 cents.

TEP and UNSE believe that the July 1, 2018, date is appropriate for resetting the initial RCP rate because the Phase 2 proceedings for both companies have been delayed by a number of factors beyond the Commission's control.[91] They assert that the five-year rolling average was intended to provide a gradual reduction in the export rate to allow the solar industry to adjust to declining export rates, and that the substantial delay in the Phase 2 proceedings has already allowed for the adjustment, at the expense of extending the cost shift. Moreover, the Companies state that the Value of Solar Decision provides that any customer who installs a DG system is grandfathered under the existing RCP for 10 years, which means the non-DG customers will be paying that RCP rate, which is only slightly below TEP's retail rate, and above UNSE's retail rate, for ten years. TEP and UNSE state that they continue to see new DG installation in the range of 300-400 per month, and that the delay in holding the Phase 2 hearing means that 1,200 to 1,600 customers will be grandfathered on net metering for 20 years.

In addition, the Companies argue that for UNSE, if the initial rate is set at 10.7 cents per kWh or higher, the first reduction should be greater than 10 percent because 10.7 cents is above UNSE's average retail rate, and more advantageous than the rate under net metering, so that there is no need to provide an adjustment period to get an RCP rate that is equal to retail. They argue that establishing an

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[90] Ex TEP/UNSE-P2-4/TEP/USNE-P2-5 (Dukes Rebuttal at 24).

[91] TEP Opening Brief at 24. TEP and UNSE state that the initial RCP rate for UNSE will be set more than three years after the end of the test year and more than a year and half after the end of its Phase 1 Decision; and the initial TEP RCP rate will be set more than two and half years after the end of the test year and a year after the TEP Phase 1 Decision.

RCP rate above retail exacerbates the cost shift.

d) Rates in Year Eleven

TEP and UNSE oppose Vote Solar and TASC/EFCA's recommendation to slowly reduce the RCP rate once it expires at the end of the ten years because to do so would extend an above-market rate beyond the period delineated in the Value of Solar Decision.[92] The Companies believe it is important to recognize that the RCP rate provides a benefit to the DG customer for only a portion of the energy produced by the DG system, as self-consumption provides the benefit of reducing the amount of energy that the DG customer needs to purchase from the utility. Moreover, they state the self-consumption benefit will not end when the RCP rate drops after ten years, but will likely increase over the remaining 15 to 20 years of the DG system's useful life.[93] They state that the ratio of self-consumption to excess energy export is controlled by the DG customers, and argue that the Commission should not incent oversizing a DG system by extending above-market compensation for excess energy further into the future as that over-compensation will ultimately be paid by the non-DG customers.[94] Further, they note that the APS settlement agreement did not include such a provision impacting the RCP rate in Year 11.

e) Net Metering Rules

TEP and UNSE argue that Vote Solar's and TASC/EFCA's claims that the Commission cannot modify or waive the Net Metering Rules to implement a DG export rate, are effectively stating that the Value of Solar Decision cannot be implemented through these Phase 2 proceedings, despite the directive of the Value of Solar Decision. The Companies agree with Staff that case law supports the proposition that the Commission can always waive application of its own rules, even when no express rule allows a waiver.[95] The Companies assert that from the time the Net Metering Rules were adopted, the Commission has been clear that that it may waive the Net Metering Rules.[96] The Companies argue

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[92] TEP Reply Brief at 11.
[93] TEP Reply Brief at 11.
[94] TEP Reply Brief at 11.
[95] TEP Reply Brief at 14.
[96] TEP Reply Brief at 14-15; *citing* the statements of then-Chief Counsel Chris Kempley at the Open Meeting adopting the Net Metering Rules: "But as you know the Commission retains the authority to waive its rules or to impose in specific instances specific requirements that might be at variance with the rules." May 11, 2008, Open Meeting Transcript, Docket No. RE-00000A-0700608 at 24-25.

that Vote Solar and TASC/EFCA are either collaterally attacking the Value of Solar Decision or attempting to re-litigate that Decision. They assert that the time to appeal the Value of Solar Decision has passed and that Decision clearly states that the Phase 2 proceedings should not re-litigate the policy decisions adopted. Finally, the Companies assert that Vote Solar and TASC/EFCA should be estopped from such argument because they agreed to a settlement agreement in the APS rate case that adopted a DG export rate and eliminated net metering for APS's new residential DG customers.[97]

f) Bill Impacts

The Company asserts that although their proposed rate design and DG export rate improve the fixed cost shift, the combined impact still allows new DG customers to realize significant bill savings. According to TEP, a typical net-zero DG customer that has an average monthly usage of 964 kWh and a 6.30 kW-DC PV system, would see a monthly bill of $34.02, a decrease of $90.93, from a "pre-going solar" monthly bill of $124.95.[98] In contrast, TEP states that the Vote Solar and TASC/EFCA proposals for TEP result in greater bill savings for the new solar customer than under current net metering.[99] TEP states that under its proposal most of the DG customers' bill savings would still be paid by non-DG customers, as the Company will only be recovering a portion of the allocated fixed costs for the DG customer. Furthermore, TEP asserts that, due to the 10-year grandfathering for new DG customers, the remaining unrecovered portion of fixed costs will go unrecovered until re-allocated to other customers in the next rate case. In addition, the Company states, the cost that it pays for exported DG power will be passed on to other customers in the PPFAC (and potentially through the REST surcharge). Because the DG export rate is above the average cost of power and the Market Cost of Comparable Conventional Generation ("MCCCG"), the Company claims it is another shift of costs to non-DG customers.[100]

g) RCP Plan of Administration ("POA")

A copy of Staff's recommended RCP POA is attached hereto as Exhibit A. TEP proposed eight revisions to the RCP POA including that: (1) the POA should include references to TEP and UNSE; (2) SGS customers should be included; (3) the RCP should include data for the rolling five-year period

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[97] TEP Reply Brief at 15.

[98] Under current rates and net metering, the same customers bill would drop to $20.10, a monthly savings of over $105. *See* Ex TEP/UNSE-P2-15 (Table of DG Rate Design Positions).

[99] Ex TEP/UNSE-P2-15. TEP Opening Brief at 26-27.

[100] TEP Opening Brief at 27.

ending December 31, 2016; (4) the RCP should apply to SGS customers; (5) bill credits should roll forward to the subsequent year unless otherwise requested by the customer; (6) the base year should be 2016; (7) market data should be used if projects of recent vintage are not available; and (8) nameplate capacity limitations should be modified.

TEP and UNSE believe that Staff disagrees with proposals 1, 3 and 6 because they are inconsistent with Staff's primary recommendations for separate RCP rates. The Companies agree that depending on the resolution of the RCP rates issues, their proposals 1, 3 and 6 may need to be modified as dictated by the ultimate rulings in this Decision.

The Companies assert that if they have a single blended RCP rate, the importance of whether to use market data in the five-year rolling average when there is no data for any of the years, is reduced. However, the Companies believe that if there are separate RCP rates, the issue becomes significant for UNSE. In that instance, the Companies request that under Section 6 which addresses the calculation of RCP rate provide as follows: "If projects of recent vintage are not available for the utility, the Company shall use pricing data from available industry sources for grid-scale solar PV projects, with priority given to projects in Arizona to the extent available.[101]

4. Residential Community Solar ("RCS") Program

TEP is proposing the same RCS program as it proposed in its 2016 REST Implementation Plan. The only difference is that TEP is now proposing a rate of $19.00 per kW instead of $17.50 per KW.[102] Under the RCS, TEP will either build, own and operate a 5 MW system interconnected with TEP's distribution system, or contract with a third-party developer to construct a solar facility of approximately 5 MW in size and interconnect this facility to TEP's distribution system.[103]

TEP describes the RCS program as a hybrid of its Bright Tucson Community Solar and TORS programs, and operates much like the TORS program. The customer's equivalent net-zero value ("Solar Rate Capacity") would be calculated in the same manner (previous annual consumption/average solar production per kW), the customer would have a fixed monthly solar payment based on their Solar Rate Capacity and the proposed tariff of $19.00 per kW; the rate would

[101] UNSE Opening Brief at 30.
[102] Ex TEP/UNSE-P2-1 (Tilghman Dir) at 7.
[103] Ex TEP/UNSE-P2-1 (Tilghman Dir) at 3.

be evaluated annually and raised or lowered if consumption increased or decreased by 15 percent, and there will be regulatory out and termination clauses.[104] TEP states that the proposed $19.00 per kW rate is intended to recover an equivalent amount of revenue from a participating customer as from a non-participating customer, and TEP expects that the customer would pay about the same each month as if they were on a budget billing program.[105] TEP would make the RCS program available to residential customers who have the legal authority to enter into a contractual agreement for the premises.[106]

In Decision No. 75815, the Commission found that

> "[w]hile we approve of the concept of the RCS, we do not approve the specific RCS tariff at this time, but defer consideration of the rate and exact terms to Phase 2 of the Rate Case. At that time, we will evaluate the reasonableness of TEP's proposed $17.50 per kW price, as well as any alternative pricing options, including what price would result under a cost-based or rate-of-return approach as suggested by Staff, or other specific recommendations offered by the parties."[107]

In that Decision, the Commission noted that "community solar represents an opportunity to bring additional renewable resource options to TEP's customers cost effectively."[108]

TEP continues to believe that the RCS is in the interest of its customers as it offers them a way to benefit from economies of scale, while still providing solar facilities in the community on the local distribution grid.[109] TEP notes that the Commission has also previously found that the RCS is available to many customers who cannot access the traditional rooftop solar market because some roofs are not suitable for rooftop solar for structural reasons or shade, and because some customers may simply prefer not to have solar DG installed on their roof. In addition, TEP states that the RCS facilities can be tied into TEP's existing control and communication network, enabling control of advanced inverter functionality.[110]

TEP states that it was the only party in Phase 2 to provide any specific proposal for the RCS program. Although Staff seemed to support a cost-based rate, TEP notes that Staff did not propose such

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104 Ex TEP/UNSE-P2-1 (Tilghman Dir) at 3.
105 TEP's proposed tariff is attached as Exhibit 8 to the application in Docket No. E-01933A-15-0239.
106 Ex TEP/UNSE-P2-1 (Tilghman Dir.) at 8.
107 Decision No. 75815 (November 21, 2016), FOF 121 at 34.
108 *Id.* at Findings of Fact 120.
109 TEP Opening Brief at 11; Ex TEP/UNSE-P2-1 (Tilghman Dir) at 7.
110 Ex TEP/UNSE-P2-1 (Tilghman Dir.) at 7.

a rate in this proceeding.[111] TEP also notes that some parties expressed the desire that the program be available to renters, but TEP asserts that the specific program it advances here is based on an ability to bind the premises.[112] TEP asserts that no party presented a specific proposal on how to include renters, specifically, how to "bind" a renter for the ten-year period if a renter cannot bind the premises.[113] TEP further notes that it provides the Bright Tucson program which is a renewable energy program that is available to all residential and small business customers, including renters.[114]

In response to the TASC/EFCA claim that the RCS program relies on subsidies, TEP states that as with the TORS program, any subsidy would be significantly less than for a net metering customer, particularly given the economies of scale realized from the utility scale RCS facility.[115] TEP states further that the Commission has already rejected the potential anti-competitive effect of such a limited program.[116]

TEP argues that the RCS should be considered as residential distributed generation under the REST Rules.[117] As such TEP seeks a waiver from the current definitions of "Distributed Generation" "Distributed Solar Electric Generator" and "Distributed Renewable Energy Resources" which currently include the phrase "sited at a customer premises…." or "located at a customer's premises".[118] TEP argues that a waiver is reasonable because "[a] facility is no less 'distributed' if it is next door to a customer or up the street from the customer."[119] TEP notes that in the earlier REST Implementation Plan proceeding, Staff expressed the belief that if a renewable generation facility is connected to the distribution grid, but simply not on a given customer premises, it would be arbitrary not to consider the facility to be distributed generation, and that community solar is a newer concept that was not contemplated when the REST Rules were adopted.[120]

Further, TEP asserts that although the Commission suggested that this issue be addressed in

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[111] Tr. at 1298; TEP Reply Brief at 12.
[112] TEP Opening Brief at 32.
[113] *Id.*
[114] *Id.* at 33.
[115] TEP Reply Brief at 12; Ex TEP/UNSE-P2-1 (Tilghman Dir) at 9.
[116] See Decision No. 75815 FoF 127 at 36.
[117] *Id.* FOF 120 at 34.
[118] A.A.C. R14-2-1801(E); R14-2-1801(G); R14-2-1802(B).
[119] TEP Opening Brief at 33.
[120] TEP Opening Brief at 33, *citing* REST Hearing Ex S-1 (Gray Dir) at 6.

Docket No. E-00000Q-16-0289, "*An Examination into the Modernization and Expansion of the Arizona Renewable Energy Standard,*"[121] that docket has not progressed, and TEP argues that it is appropriate and necessary to address the issue for the limited purpose of this discreet 5 MW RCS program.[122]

5. Bright Tucson

TEP states that the Bright Tucson program provides a solar option for all TEP residential and small commercial customers, including renters. Under the current Bright Tucson program, any TEP residential or small commercial customer can contract for 150 kWh blocks of solar energy in exchange for a $0.02 per kWh premium over standard retail rates. As part of the program, the customer also receives: (1) a fixed base fuel rate for up to 20 years; (2) a proportional discount on the Commission–approved REST surcharge; and (3) a proportional discount on the Commission-approved Purchased Power and Fuel Adjustment Clause ("PPFAC") surcharge. In this proceeding, TEP seeks to lower the premium from $0.02 per kWh to $0.01 per kWh.

TEP states that the original Green Pricing premium was designed during the 2009-2010 timeframe when the cost of large community scale solar was in the $0.10-$0.14 per kWh range, which was significantly higher than traditional fuel costs. TEP explains that the premium was designed to allow customers the opportunity to support locally generated solar while helping to offset the costs to other rate payers. TEP believes that because the cost of large-scale solar facilities has dropped significantly in recent years, it is appropriate to lower the premium while maintaining the specific customer benefits associated with the program. In response, TEP asserts that this minor adjustment will further promote the existing community solar program and offer an alternative to customers who are not able to "go solar" on their own. TEP states that the program does not require a term commitment and participation may be terminated at any time without penalty.

During the preceding the only party to oppose TEP's proposed reduction was Mr. Plenk who believed that the premium be reduced to zero. In response, TEP asserts that because the base fuel rate is fixed for up to 20 years, that it is appropriate to maintain a premium, otherwise, customers would

[121] Decision No. 75815 at 38.
[122] TEP Opening Brief at 33.

have the incentive to exit the program when the rate went down and re-enter the program at a lower rate.[123]

6. Response to RUCO's Time of Generation ("TOG")

TEP states that it does not oppose RUCO's alternative RCP rate if: (1) the RCP rate only applies to energy exports from solar DG systems; (2) the rates adjust commensurately with each change in the DG export rate; and (3) the proposal is established as a pilot program subject to evaluation and adjustment, if necessary, to address any unintended consequences or if it is deemed not to be beneficial to the system or customer base. TEP asserts that if the Commission approves such a pilot program, that it should require that an appropriate tariff or rider be submitted as a compliance item.[124] TEP believes it is important to note that the record is not sufficient to adopt a specific tariff for the TOG at this time.[125]

7. Response to TASC/EFCA Residential Storage Incentive Rate

In response to arguments presented in Initial Briefs, TEP and UNSE assert that although TASC/EFCA and Staff have requested that the Companies adopt a residential rate option that would incent the deployment of storage facilities such as batteries, no party has presented a specific proposal for TEP or UNSE that reflects the specific circumstances of each company, such as cost of service, or revenue requirement. The Companies state that they are not necessarily opposed to a storage-friendly pilot program, but claim that there is not a "fulsome and complete proposal, based on the record, that could be approved in this phase of the proceeding."[126]

TEP and UNSE state that they do not believe that additional storage-specific rates should be created, and assert that the three-part rates already available to the Companies' customers are cost-based and provide appropriate price signals for customers regarding the installation of storage.[127] The Companies strongly believe that the "custom fit non-cost-based rates designed for a specific technology will be inherently unfair and rendered obsolete as new technologies are adopted."[128] However, the

[123] TEP Opening Brief at 35.
[124] TEP Opening Brief at 35.
[125] TEP Reply Brief at 13.
[126] TEP Opening Brief at 36.
[127] TEP Reply Brief at 13.
[128] Ex TEP/UNSE-P2-11 (Jones RJ) at 27.

Companies also state that if the Commission is inclined to adopt a pilot program for storage-friendly rates, it should require that appropriate tariffs or riders be submitted as a compliance item because the record is inadequate to adopt specific tariffs at this time.[129]

The Companies also claim that up-front incentives designed to promote policy objectives (e.g. increased PV, increased storage, west-facing roofs) are the more appropriate and economically efficient way to incentivize Commission policy and would avoid very expensive and time-consuming billing system and other potential modifications."[130] The Companies believe that if it is deemed necessary to create an additional storage-specific rate, that rate should be modeled after the current Large General Service Time-Of-Use tariff rate design that includes seasonal and time differentiated demand charges that recover most of the transmission and delivery costs, time-of-use volumetric charges to recover fuel costs, and a 75 percent ratchet applied to the on-peak demand.[131] According to the Companies, "use of these principles greatly improved the economics for customers installing energy storage by giving them access to the large seasonal price arbitrage that is unavailable on non-ratcheted monthly charges or daily charges. Without the ratchet, the Companies claim customers installing storage only have access to the small daily time-of-use price arbitrage."[132] The Companies request that if the Commission would like a non-ratcheted storage-friendly rate as part of a pilot program, they should also be allowed to submit both a ratcheted option and a non-ratcheted option to give customers a choice.

In response to the TASC/EFCA recommendation for a daily demand charge as part of a storage friendly rates, the Companies state that they do not currently have any active rates with daily charges, or billing systems capable of implementing daily charges.[133] They argue that if it is deemed necessary to have a daily demand charge rate, then the cost of changing the Companies' billing systems should be borne by the customers benefiting from the rate as it is a custom fit, non-cost-based rate designed for a specific technology.[134]

8. <u>Response to AECC's Cost-Recovery Proposal</u>

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[129] TEP Reply Brief at 13.
[130] TEP Opening Brief at 36.
[131] TEP Opening Brief at 36; TEP Reply Brief at 13; Ex TEP/UNSE-P2-11 (Jones RJ) at 27.
[132] TEP Reply Brief at 14.
[133] TEP Reply Brief at 14.
[134] TEP Reply Brief at 14.

TEP and UNSE agree to AECC's proposal for recovering the cost of DG energy purchases through the PPFAC up to an amount equal to the Companies' MCCCG, and through the REST surcharge for the above-market cost of purchased DG energy.[135]

The Companies do not, however, agree with AECC's proposed limitation on the ability to increase the REST caps based on DG energy purchases.[136] TEP and UNSE state that the REST caps are the result of many considerations by the Commission, and that trying to set what the Commission can and cannot do with respect to REST caps in this docket would be challenging and may inappropriately limit the Commission's flexibility to make policy decisions. The Companies assert that such determinations should be made in the REST dockets where caps can be set based on all pertinent information.

B. <u>AIC</u>

AIC asserts that to conform with the Value of Solar Decision, both the export rate and rate design for new solar DG customers need to balance: (1) the social and economic incentives supporting new and existing solar DG; (2) the economic impact of renewable energy policies on utility infrastructure and capital costs; and (3) the improved technologies that allow for more accurate measures of the financial impact on the parties. AIC states that the initial implementation of the rates should focus on improving regulatory certainty and sending a positive signal to credit rating agencies and analysts regarding the regulatory environment in Arizona. AIC recommends that to do this, the export rates must: (1) gradually transition customers, utilities, and the external solar industry away from full retail net metering and towards a more market-based approach; (2) gradually lessen cost shifts between customers with and without solar DG, by improving the utility's ability to recover an equitable share of fixed grid-related costs from DG customers; and (3) maintain fairness among all customers, while allowing the utility a reasonable opportunity to earn its authorized rate of return.[137]

1. <u>Resource Comparison Proxy</u>

AIC argues that the RCP methodology should: (1) use the five most recent years of data; (2) only account for the benefits of avoided transmission and distribution costs that are supported by

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[135] TEP Reply Brief at 15.
[136] TEP Reply Brief at 15.
[137] AIC Brief at 1 *citing* Ex AIC-P2 - 2 (Yaquinto Surr) at 3.

evidence; (3) use a combined RCP rate for TEP and UNSE; (4) set the Year 2 rate in this proceeding; and (5) base the RCP rate on specific circumstances and data of the Companies, and not model it after the rate contained in the APS Settlement Agreement.[138] AIC recommends adopting a Year 1 RCP rate of 9.73 cents per kWh, approving a Year 2 RCP rate of 8.76 cents per kWh to take effect no later than 12 months after the effective date of this Decision, and approving a rate design that includes a GAC and DG Meter charge.

AIC asserts that a five-year rolling average to calculate the RCP allows for fresh data to be used in establishing the proxy for DG solar exports.[139] AIC states that TEP and UNSE have up-to-date information (through 2017) on their own utility scale projects and PPAs and therefore, the actual data should be used. AIC acknowledges that there has been much testimony about conflicting statements in the Value of Solar Decision that refer to a five-year rolling average (without mention of the test year) and the two instances in the Decision that refer to the projects within five years "up to and including the test year."[140] AIC recognizes that normally, the difference in the calculation would not be significant, but believes that the delay in these Phase 2 proceedings makes using the test year as the last year in the analysis a poor proxy for current costs.[141] AIC argues that using old and stale data only exacerbates the problems that the Value of Solar Decision and the RCP rate seek to solve; that is, appropriately valuing exported solar and reducing the cost shift between non-DG and DG customers. Because solar costs have declined in recent years, AIC argues, using the older more expensive projects in the rolling average, does not correct, but perpetuates the cost shift. Nonetheless, AIC states that it could support the position of the Companies, Vote Solar, RUCO and Staff to use data through 2016.[142]

AIC supports the conclusions of the Companies, RUCO and Staff that the evidence has not demonstrated that there are any benefits of avoided costs to transmission and distribution capacity, and thus, a T&D adder is not appropriate.[143]

AIC supports a single RCP rate (9.73 cents per kWh) for both TEP and UNSE as the Companies

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[138] AIC Brief at 2.
[139] Decision No. 76295 at 148.
[140] Compare Decision No. 76295 at 148, 149, 150, 153 170, and 171 with pp 153 and 172.
[141] AIC Brief at 3. AIC notes that UNSE's test year was 2014, and TEP's was in 2015, which if used as the last years in the rolling average, would mean that data from 2009 and 2010 would be used to set rates that would go into effect in 2018.
[142] AIC Brief at 4.
[143] AIC Brief at 4.

are part of the same corporate family, share company management and operations resources and well as facilities, and because utilizing a combined RCP rate will reduce administrative burdens and regulatory lag. In addition, AIC states that because UNSE is a relatively small utility, it is logical to use data from its sister company to fill in gaps for the RCP calculation. AIC notes that TASC/EFCA's recommended RCP rate of 12.5 cents per kWh would make the UNSE rate higher than its average residential rate, which, AIC argues, would increase cross-subsidization of solar customers by non-solar customers, and misconstrue the policy goals of the Value of Solar Decision and rate-making in general.[144]

AIC recommends that the Year 2 RCP rate of 8.76 cents per kWh take effect 12 months after a decision in this matter. AIC believes that setting the RCP rate to more closely reflect market-based costs is important to mitigate the cost shift, and further, that because 2017 cost data is known, approving that rate now encourages administrative efficiency and reduces regulatory lag. In the circumstances of this case, AIC's support for the Year 2 RCP rate taking effect in 12 months is predicated on the lower combined RCP rate of 9.73 cents per kWh being adopted initially; otherwise, AIC recommends a quicker reduction in the RCP rate by July 2018. AIC states that if a higher rate is adopted it will be because older, staler data is used in the rolling average, and that rigidly adhering to the 12-month reset would lock in the initial rate's failure to use current data. AIC contends that given the 10 percent reduction limitation, the longer time frame before the Year 2 RCP rate takes effect, the longer the continuation of the subsidization that the Value of Solar Decision seeks to reduce.[145] AIC asserts that the APS RCP rate was set in the context of a rate case proceeding that was conducted in a single phase and as part of a settlement, and there is no need to rely on that case with respect to getting the RCP rate for TEP and UNSE where a robust record has been established.[146]

AIC believes that the Value of Solar Decision expanded the ratemaking principle of gradualism to include mitigating the risk to the solar industry due to regulatory changes to the export rate and rate design, but notes that the RCP rate and new rate design options will have no impact on existing net

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[144] AIC Brief at 5.
[145] AIC Brief at 6.
[146] AIC Brief at 7-8.

metering customers because they can stay on their current rates.[147]

2. Rate Design

AIC states that TEP and UNSE have submitted open and transparent CCOSS analysis and presented reasonable rate designs for solar DG supported by the CCOSS. AIC supports the rate design proposed by the Companies, Staff, and RUCO.[148] AIC asserts that it is necessary for solar DG customers to pay a GAC and a DG Metering Fee in order to recover fixed grid costs and to lessen the cross-subsidization of DG customers by non-DG customers. AIC argues that TEP and UNSE can have different rate designs for DG and non-DG customers because they are separate classes of customers with distinguishable characteristics in the ratemaking process.

C. IBEW

IBEW supports TEP's Phase 2 rate design and DG export proposals. IBEW asserts that the Commission must make its decisions in these dockets based on the evidence and has a duty to provide appropriate rules and orders for utility employees and utility patrons, not industry groups "looking to bankroll their profits on the backs of Arizona's utility customers."[149] IBEW argues that the solar industry's assertions concerning job loss, and collapse of rooftop solar are conclusory and not supported by fact.[150]

Moreover, IBEW argues that fears of job loss and reduced economic growth are not within the purview of the Commission.[151] IBEW states that those opposing the Company's proposals fail to acknowledge that the Arizona Constitution mandates that the Commission make rules and issue orders "for the convenience, comfort and safety, and the preservation of the health of employees and patrons of [public service corporations]."[152] IBEW criticizes the solar industry for failing to acknowledge their reliance on the utility's grid. IBEW supports TEP's and Staff's proposals because they take into consideration all patrons of the utility.[153]

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147 AIC Brief at 9.
148 AIC Brief at 8.
149 IBEW Reply Brief at 1.
150 *Id.* at 2.
151 *Id.* at 3.
152 Ariz. Const. art. XV § 3.
153 IBEW Reply Brief at 4.

D. RUCO

1. Time of Generation DG Export Rate

RUCO asserts that its TOG Proposal is designed to encourage west facing rooftop systems and systems that incorporate solar storage, which in turn will encourage reduced peak demand. RUCO notes that in TEP's service territory nearly 38 percent of DG solar installations are either north or east facing, 37 percent are south facing, 7 percent are southwest facing, and only 19 percent are west facing.[154] RUCO believes that these statistics show that reducing the utilities' peak demand through solar generation has largely been overlooked.[155]

Under RUCO's TOG Proposal, the RCP will be applied to systems that orient to the south, but the rate for rooftop systems that orient to the west, or that incorporate solar storage, will be higher when system demand is at peak. Lower rates will be applied at shoulder times and even lower rates at off-peak times. RUCO recommends that the variable pricing be applied to all production, not just exports.[156] The TOG rate would decline by a fixed percentage per year equal to the flat RCP rate, with the same ten-year lock. Under this proposal, the on-peak period is pegged to the corresponding Company's on-peak summer period for its TOU rate (i.e., 3-7 p.m.), and the time period would hold year-round, weekends and holidays included. Based on a TOU RCP of 9.7 cents per kWh, RUCO recommends a peak rate of 21 cents per kWh, a shoulder rate of 12 cents per kWh, and an off-peak rate of 3 cents per kWh.[157]

RUCO states that there was little that the parties could agree upon in these proceedings with respect to solar rate design, except for RUCO's TOG Proposal. RUCO claims that all parties agree with the proposed concept of better aligning peak solar generation with the peak demand. RUCO asserts such a proposal promotes current and new technologies, grid efficiencies, and will result in quantifiable avoided costs. RUCO believes that the utilities make a solid argument that solar DG generation, which peaks around noon, does little to reduce peak demand which occurs in the later part of the afternoon. RUCO notes that if peak demand is not reduced, there will not be quantifiable avoided costs.[158]

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[154] Ex RUCO-P2-2 (Huber Surrebuttal) at 30.
[155] RUCO Brief at 6.
[156] Ex RUCO-P2-2 (Huber Surrebuttal) at 24-25.
[157] RUCO Brief at 4.
[158] RUCO Brief at 2.

RUCO asserts that a flat RCP rate also does little to advance solar technologies, reduce peak demand, modernize the grid, or produce quantifiable avoided costs. RUCO believes that when the Commission adopted a methodology for gradually transitioning away from net metering in the Value of Solar Decision, it did not intend to ignore ways to modernize the grid and improve system efficiencies.[159]

2. Rate Design

In addition to its TOG Proposal, RUCO recommends four other options for residential DG customers as follows:[160]

Recommended Rate Options for Residential DG Customers	Applicability and RCP Treatment	Details
3-part TOU	Default for DG customers. Standard flat RCP with a 10-year lock	On-peak hours of 3 p.m. to 7 p.m. for summer, 6-9 a.m. and 6-9 p.m., winter – weekdays, excluding designed holidays, for both winter and summer (May-Oct) seasons.
2-part TOU rate with a Grid Access Charge	Optional for DG customers TOU adjusted RCP rate with a 10-year lock	Flat volumetric rate, slightly higher Basic Service Charge.
RPS Credit Option	Optional for DG customers. Starting RCP value applies to all PV production and is locked for 20 years.	A customer must be on a TOU rate for their underlying tariff.
Advanced DG Experimental Rate	Optional for DG customers. No RCP for exports. Export rate is linked to underlying rate plan with no netting or banking.	Limited to a fixed number of customers. On-peak hours of 3 p.m. to 7 p.m. for summer, 6-9 a.m., 6-9 p.m., winter-weekdays, excluding designated holidays, for both winter and summer (May-Oct) seasons.

RUCO states that the final positions of Staff, the Companies, and RUCO are aligned for most of the rate elements for both TEP and UNSE, including the GAC, Basic Service Charge ("BSC"), Energy Delivery Charge, Base Power, PPFAC Charges, and Statement of Charges. The parties disagree, however, about the RCP rate and methodologies for calculating it.

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[159] RUCO Brief at 3.

[160] RUCO Brief at 5.

3. Resource Comparison Proxy

RUCO recommends a 9.7 cent/kWh blended RCP for both Companies.[161] RUCO notes that the current market rate for utility scale solar is below 3 cents/kWh; and RUCO believes that its proposed rate, if anything, is on the high side.[162] RUCO questions why, if the utilities can acquire solar generation cheaply from other sources, the Commission should require them to pay an RCP rate more than 3 times the wholesale rate, and believes that there is no logical reason why the utilities should pay more than retail.[163] RUCO notes that the Commission adopted the RCP and avoided cost methodologies in the Value of Solar Decision as a way to gradually transition away from net metering, and RUCO argues that the Commission clearly intended the transition to encompass a lower rate than the net metering rate to address the cost shift.[164] RUCO claims that because its blended rate is below TEP's retail rate and slightly above UNSE's retail rate, it best follows the Commission's directives in the Value of Solar Decision. RUCO argues that the other parties' recommendations are unjustifiably high because they use out-of-date and incomplete inputs that do not comply with the directives in the Value of Solar Decision.[165]

RUCO does not believe that the parties or Commission should re-litigate the Value of Solar Decision. RUCO states that the Value of Solar Decision is clear that the inputs to the RCP formula should be updated annually.[166] RUCO asserts that the Value of Solar Decision did not provide for an annual step down or any other treatment after the 10 year lock-in period, and argues that the Decision's silence on an issue does not mean that this Phase 2 proceeding is the appropriate time or place to litigate the issue.[167] Further, RUCO notes that the Value of Solar Decision does not distinguish the number of years of available data necessary before the parties must use market data, nor does it make market data

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[161] RUCO Brief at 6.

[162] Ex RUCO-P2 (Huber Surrebuttal) at 5. TEP recently signed a solar plus storage PPA for 4.5 cents/kWh with the solar portion projected at below 3 cents/kWh.

[163] The current retail rate for UNSE is 9.2 cents/kWh and 10.8 cents/kWh for TEP.

[164] RUCO Brief at 7. At pages 175-176, the Value of Solar Decision provides: "[W]hile we refrain from commenting on the appropriateness of modifying any particular rate design as part of this proceeding, the Commission is committed to modifying residential rate design in a manner that mitigates the recognized cost shift caused by rooftop customer's self-consumption.

[165] RUCO Brief at 8.

[166] RUCO Brief at 8. Decision No. 75859 at 173. "However, once the formula has been set, the inputs to the formula should be updated annually to provide for more measured adjustments. We believe that this will reduce the risk of dramatic changes to customers and the solar industry and is consistent with our interest in rate gradualism.

[167] RUCO Brief at 9.

a substitute only when data is not available for all five years. Thus, RUCO believes that Staff's approach of using market data only if there are no years in the five-year period when projects went into service is inconsistent with the spirit and logic of the Value of Solar Decision. RUCO states that Staff's proxy rate for UNSE is inflated as a result because it relies on projects in the earlier years when rates were higher. RUCO states, however, that the "most troubling" aspect of Staff's interpretation is the staleness of the data used to arrive at the RCP rate for UNSE.[168] RUCO believes there is a danger from data manipulation under Staff's approach if utilities opt not to build projects in a rising cost market.[169] RUCO believes that the Commission intended the five-year average pricing to be a market-based methodology and the RCP to reflect current market based pricing. RUCO asserts that its methodology of using projects from 2012-2016 for UNSE and using TEP projects as proxies when UNSE had no projects (resulting in an RCP rate of 8.2 cents/kWh for UNSE) most closely follows the intent to use market pricing.[170] RUCO believes that maintaining the integrity of the RCP is critical for the long-term success of the methodology, and the Commission should not use "gimmicks," such as post-test year data, to reach an acceptable compensation rate, and if an adder is needed to maintain the viability of the rooftop solar industry, it should be transparent and adjustable annually.[171] With respect to Staff's and the Companies' recommendation for an RCP of 10.7 cents/kWh with a six-month reset, RUCO argues that the higher rate for the shorter period is unwarranted as the goal of the RCP rate should not be to approximate the net metering rate.

RUCO does not support adders for transmission and distribution facilities.[172] RUCO states that "[f]or there to be a true avoided cost, the DG production must be located on a circuit where there is a capacity need, it must be perfectly timed to coincide with the capacity needs, and it must displace 100%

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[168] RUCO Brief at 11.
[169] RUCO Brief at 12.
[170] RUCO Brief at 13; RUCO Reply Brief at 6 & 9. RUCO views its position on how to resolve the ambiguity in the Value of Solar Decision over which years to use in calculating the RCP from the perspective of the spirit and objective of the Value of Solar Decision, and from that perspective, cannot understand how using stale data will result in the current actual value of DG. RUCO also disagrees with Staff's approach to leave certain years blank if there were not projects put into service because it does not consider how the average is affected by increasing the weight of other years. RUCO argues that to neglect years where data peculiar to the Company is unavailable will not result in a representative market value for the five years in question.
[171] RUCO Brief at 13.
[172] RUCO Brief at 14.

of the capacity need."[173] RUCO states that no party has made such a calculation and RUCO questions whether it is even possible; at best, RUCO claims, the Commission would be dealing with an estimate. RUCO asserts that if parties had wanted, they could have engaged in discovery and conducted a hosting analysis, but that in the absence of such analysis, unreliable estimates should not be adopted. RUCO argues that the burden is on the party propounding the position to support its position and the Value of Solar Decision did not shift the burden.

RUCO asserts that the Value of Solar Decision was obviously concerned with maintaining the integrity of the RCP and the Avoided Cost methodologies and rejected speculative quantifications of costs.[174] RUCO interprets the Commission's plain language in that Decision to mean that in order for the RCP to reflect the actual value of DG, its calculation should be based on actual numbers not speculation.[175] RUCO argues that the studies conducted by Vote Solar and TASC/EFCA were too crude and violate the Value of Solar Decision because: (1) neither Vote Solar nor TASC/EFCA identified any actual project or general locations where solar exports might defer a distribution or transmission project; and (2) Mr. Beach included self-consumed solar as the basis of his analysis, while the Value of Solar Decision clearly only pertains to exports which, RUCO notes, occurs in the early afternoon rather than during peak times.[176] RUCO states that the more beneficial solar production (i.e. that produced during peak times) is often self-consumed. RUCO argues that neither Vote Solar nor TASC/EFCA examined how only mid-day export can lead to transmission and distribution savings.

RUCO does not believe that adopting Staff's, the Companies', or RUCO's RCP proposals will drastically affect the economics of solar.[177] RUCO states that when the actual proposals for the RCP are compared with actual retail/net metering numbers, there is a large disconnect with the solar industries' arguments, because an RCP proposal that is either greater than, or only slightly below, the current retail rate will not devastate the rooftop solar industry. RUCO acknowledges that the first year RCP is not the entire story, and recognizes there will be a negative impact, but believes that the impact

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[173] RUCO Brief at 14.

[174] E.g., Decision No. 75859 at 150: "We agree with the parties who argued that quantifying the societal and economic development benefits of DG in an avoided cost forecast, as proposed by Vote Solar and TASC, is a speculative endeavor that has no place in ratemaking."

[175] RUCO Reply Brief at 5.

[176] RUCO Reply Brief at 5.

[177] RUCO Reply Brief at 1-3.

is not likely to be as catastrophic as the solar industry argues. RUCO states that the current average payback for rooftop solar under net metering is 7.8 years, and if the Commission adopted RUCO's TOG proposal, the average payback for a system with south facing panels would be 8.2 years and for west-facing systems 8.0 years.[178] Moreover, RUCO points out that the Value of Solar Decision adopted Staff's RCP methodology which limits the reduction in the RCP to 10 percent annually, a minor change in the rate, which RUCO claims is causing the same "knee-jerk" reaction from the solar industry as always.[179]

4. Community Solar

RUCO supports TEP's Bright Tucson Program, and believes that it will provide renters with an option for participating in clean energy. RUCO states it would "like to see some consideration for a third-party community solar program with bill credits set competitively below retail."[180]

RUCO however, did not address TEP's proposed RCS program in its Briefs. In Mr. Huber's testimony, RUCO supports the concept of the RCS, but would still like to see consideration of a third-party community solar program with bill credits set competitively below retail.[181]

5. Residential Battery Storage

RUCO states that it could support a daily demand charge if TEP's billing system could implement it and if the daily demand charge was also accompanied by a more standard demand charge to ensure proper cost causation and recovery.[182] RUCO states that the problem with a daily demand charge is that although it has the benefit of not over-penalizing for one bad day, acting alone, it does not ensure proper cost recovery for the Company and nonparticipating ratepayers.[183] If the Company's billing system cannot implement a daily demand charge without significant expense, and the additional demand charge as recommended by RUCO is not included, then RUCO reverts to its original storage rate proposal with an on-peak monthly demand charge.[184]

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178 RUCO Reply Brief at 3; Ex RUCO-2 at 28.
179 RUCO Reply Brief at 4.
180 RUCO Brief at 15.
181 Ex RUCO -P2-1 (Huber Reb) at 20.
182 RUCO Reply Brief at 10-11.
183 Tr. at 871-872.
184 RUCO Reply Brief at 10.

6. Data Availability (Plenk Proposal)

RUCO supports Mr. Plenk's recommendation that the Companies should supply customers with their historic hourly load data when requested, and that it should be set up as soon as practical and provided in a low cost and streamlined way using an electronic format.[185]

E. TASC/EFCA

1. CCOSS and Rate Design

TASC/EFCA argue that the basic premise of the Companies' GAC is flawed because no other generator is asked to pay for the cost of the grid when the Companies take that generator's power and deliver it to their own customers.[186] TASC/EFCA argue that the Companies spuriously assume that DG generators are the ones "using the grid" when the Companies are delivering DG-generated power to the utilities' own customers. As a result, TASC/EFCA asserts the CCOSS assigns unwarranted costs to the DG customer by calculating the DG class NCP using the time of maximum delivered and exported load added together.[187] TASC/EFCA argue that the Companies' CCOSS must be rejected for this unsupportable flaw that treats DG generators differently from all other generators. TASC/EFCA argue that if the CCOSSs are not corrected, the Companies will be recovering the same capacity costs twice—once from all customers and again from DG customers. TASC/EFCA argue that the cost to serve DG customers should be based on the delivered load, as it is with other customers.

TASC/EFCA state that in terms of cost recovery, when the Companies acquire power from DG customers that they then deliver to other customers, the acquisition is treated the same as the acquisition from PPAs with third–party generators. TASC/EFCA state that third-party generators and DG generators both deliver power to the utility at the point of interconnection and relinquish all control of the power to the Companies after the Companies take possession.[188] TASC/EFCA criticize Mr. Jones' testimony that the distinction between third-party PPAs and DG generators is that the former are not retail customers. TASC/EFCA assert that generators are not charged for the capacity necessary to distribute the electricity they generate because it is the retail customers who pay for the capacity

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[185] RUCO Reply Brief at 10.
[186] TASC/EFCA Opening Brief at 4.; TASC/EFCA Reply Brief at 13.
[187] TASC/EFCA Opening Brief at 4; Ex TEP/UNSE –P2-9 (Jones Dir) at 4.
[188] Tr. at 162, 175 and 274.

necessary to deliver power to them.[189] TASC/EFCA claim that the Companies' witnesses admit that it is the utility, and not the generator, that is "using the grid" when the utility delivers third-party generated power to the utility's own customers.[190] They note that Mr. Smith, for Staff, also testified that the utility uses the grid when it takes electricity from the generator and distributes it to its customers.[191] TASC/EFCA's witness Mr. Beach explained the flaw they find in the Companies' position:

> The fundamental flaw in the utilities' approach is the assumption that, when a solar customer exports power to the grid, it is the solar customer who is taking service from the utility. This is obviously not true: when a solar customer exports power to the utility, it is the solar customer that is providing a service – generation – to the utility. The utility takes title to the exported power at the solar customer's meter. It is the utility that delivers the exported DG power to the DG customer's neighbors. It is the utility that is compensated by the neighbors for the service that the utility provides in delivering the DG exports to them. [] DG exports are a service-generation – that the DG customer provides to the utility, and it is a service that ends at the DG customer's meter when the utility accepts the DG exports into its distribution system. This is no different in the generation service that any other third-party generator, of any size, provides to the utility. The service that the generator provides ends at the generator's busbar where the utility accepts the generated power into its transmission and distribution system.[192]

TASC/EFCA argue that cost of service should be based on delivered load to the customer, but in the case of DG customers, the Companies disregard significant precedent for the standard cost of service study cost allocation methodology and single out DG customers to be assigned costs of load that is not delivered to, or used by, the DG customers.[193] They also argue that the Companies' methodology double-recovers the delivery costs, and assert that Mr. Jones, for the Companies, admitted that the costs of the capacity needed to deliver DG generated energy to non-DG customers was already allocated to all retail customers in the CCOSS.[194]

In response to the Companies' claims that "[u]sing both the import and the export capacity

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[189] TASC/EFCA Opening Brief at 6-7.

[190] Tr. at 275. Ms. Gray testified for the Companies that third parties with PPAs are not using the grid to deliver power to the utility because they deliver it at the point of interconnection, at which point it is on the utility system. *See* TASC/EFCA Reply Brief at 14.

[191] Tr. at 1190. TASC/EFCA claim that Mr. Smith's admission demonstrates that the DG customer is not the one utilizing the grid while exporting and as a result, the associated costs should be allocated to the consumers of the power, not the generator.

[192] Ex TASC/EFCA–P2-5 (Beach Surr) at 22-23.

[193] TASC/EFCA Opening Brief at 9.

[194] Tr. at 364-365.

requirements is essential for a partial requirements customer in order to incorporate the appropriate maximum burden they place on the system,"[195] TASC/EFCA cite Mr. Jones' testimony that the Companies have designed rates for non-DG partial requirements customers "based on the full requirements rate."[196] TASC/EFCA assert that this means the Companies do not treat non-DG partial requirements customers in the manner that they claim is essential for DG customers.[197] They argue "[i]t is not credible for the Company to argue it is essential that it do something to DG customers that it does not do to non-DG partial requirements customers."[198]

TASC/EFCA believe it is telling that Staff offered no analysis of the CCOSS methodology in its Closing Brief, and has not explained how it could support allocating costs to DG customers.[199] TASC/EFCA argue that no party offered a compelling reason to single out DG customers in order to allocate costs to them that are not allocated to any other generator.

Furthermore, TASC/EFCA argue that the evidence proves that DG customers place less burden on the grid than average residential customers. TASC/EFCA assert that their corrections to the CCOSS show that the costs to serve DG customers are less than the cost to serve full requirements residential and small commercial customers.[200] They note that Ms. Kobor's testimony for Vote Solar shows that at the time of residential class peak, DG customers "have a lower capacity per customer as opposed to the same customer who did not have solar."[201]

In addition, TASC/EFCA argue that the proposed GACs ($2.50 per kW for TEP and $1.00/kW for UNSE) violate the principle of gradualism. They assert that the fixed charge will send no price signal other than incenting a customer to install a smaller DG system, and would be the highest such charges in the state, as well as be entirely new to TEP and UNSE customers.[202] They argue that the dramatic fee hike is not in keeping with gradualism.

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195 TEP Opening Brief at 11.
196 Tr. at 360-361.
197 TASC/EFCA Reply Brief at 14.
198 TASC/EFCA Reply Brief at 14.
199 TASC/EFCA Reply Brief at 14. TASC/EFCA notes that in its Opening Brief, Staff merely states that it accepted the Companies' CCOSS.
200 TASC/EFCA Opening Brief at 10; Ex TASC/EFCA-P2-4 (Beach Dir) at 14.
201 Tr. at 1104.
202 TASC/EFCA Opening Brief at 10. They note that the experience with APS's Grid access charges is vastly different than in this case, as the APS Grid Access Charges was set at $0.70 per kW for five years before being raised to $0.93 per kW in the recent rate case.

TASC/EFCA also argue that the Companies have not met their burden to justify new charges on DG customers.[203] They state that the Net Metering Rules place a heavy burden on utilities looking to levy charges on customers with DG solar devices. A.A.C. R14-2-2305 states:

> Net Metering charges shall be assessed on a nondiscriminatory basis. Any proposed charge that would increase a Net Metering Customer's costs beyond those of other customers with similar load characteristics or customers in the same rate class that the Net Metering Customers would qualify for if not participating in Net Metering shall be filed by the Electric Utility with the Commission for consideration and approval. The charges shall be *fully supported* with cost of service studies *and benefit/cost analyses. The Electric Utility shall have the burden of proof on any proposed charge*. (Emphasis added.)

TASC/EFCA assert that the Companies did not perform a cost/benefit analysis nor carry their burden of proof to justify the high GACs.[204]

2. <u>Resource Comparison Proxy</u>

TASC/EFCA propose that the initial RCP be set at 12.5 cents/kWh for both utilities. Their proposed RCP includes a 2-cent/kWh adder to recognize the costs avoided by DG solar that are not avoided by other central station generation including solar and non-solar generation. The rate is based on utility-scale costs for five years ending December 31, 2015, and factors in distribution and transmission losses as well as avoided transmission and distribution costs.[205]

TASC/EFCA argue that an initial RCP greater than the retail rate does not mean that the value is actually higher than current net metering, as the first year of the RCP "does not tell the entire story in such a comparison."[206] They state that there are significant differences between the current net metering structure and the RCP, each of which worsens the economics of DG solar to the customer under the RCP compared to net metering. And furthermore, they assert, even an RCP set above retail could result in a diminution in the cost shift or a higher rate of recovery for the utility.[207] TASC/EFCA state that one of the most obvious advantages to the DG customer of net metering over the RCP methodology is the length of the period of certainty in rates because the RCP is only locked-in for ten

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[203] TASC/EFCA Opening Brief at 11.
[204] TASC/EFCA assert that Ms. Gray admitted that the Companies didn't perform a cost/benefit analysis when she testified that the Companies "didn't quantify the benefits or necessarily the costs." Tr. at 269.
[205] TASC/EFCA Opening Brief at 12.
[206] TASC/EFCA Opening Brief at 12.
[207] *Id.* at 13.

years while current net metering provides twenty years of certainty based on the Commission's current grandfathering policy. TASC/EFCA point out that uncertainty is increased because the RCP in year 11 is unknown, and DG customers will not know the level of compensation they can receive for more than half of their facility's useful life.[208] A third disadvantage TASC/EFCA see with the RCP methodology is that the value of net metering rises over time as retail rates increase, but the RCP value is fixed. In addition, TASC/EFCA note that each successive tranche of utility customers gets a lower RCP, while net metering is constant, such that the economics of installing a system become less favorable over time.[209] Finally, TASC/EFCA claim that the difference between the value of the self-consumed and exported power does not align with a TOU rate structure.[210] They argue that under the RCP, an exported kWh will be worth something different than a self-consumed kWh, which adds an extra level of complexity to the analysis of a DG facility as the customer must make long-term assumptions about their future energy usage. Furthermore, TASC/EFCA argue, a fixed RCP does not incent a consumer to export during the system peak.

a. <u>T&D Adder</u>

TASC/EFCA argue that avoided transmission and distribution costs have been demonstrated and must be added to the RCP.[211] They state that it is future avoided costs that must be considered pursuant to the Value of Solar Decision. They claim that those parties arguing against a T&D adder are focusing on costs incurred in the past, and are asking the Commission to adopt a standard that makes it impossible to quantify future avoided T&D benefits. They argue that failing to calculate future avoided costs because the costs have not yet been avoided undermines the Value of Solar Decision.

In addition, TASC/EFCA argue that the Companies admitted that DG provides benefits, but made no attempt to quantify these benefits,[212] and that the Commission can have no basis for any decision that the costs of DG outweigh its benefits when the Companies did not perform even a basic analysis. Moreover, TASC/EFCA assert that the Companies did not look at the costs that DG avoids

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[208] TASC/EFCA Opening Brief at 13-14.
[209] TASC/EFCA Opening Brief at 14.
[210] *Id.*
[211] TASC/EFCA Opening Brief at 15.
[212] TASC/EFCA Opening Brief at 16, citing Ms. Gray's testimony that "we didn't quantify the benefits or necessarily the costs." Tr. at 269.

when compared to central station generation.[213] TASC/EFCA state that the Value of Solar Decision is unequivocal that DG is to be compared not only to utility scale solar, but also to other "central station generation."[214]

TASC/EFCA assert that their estimate of avoided transmission and distribution cost benefits is reasonable and supported.[215] They state that DG solar was shown to reduce load during times of system peak,[216] and that it is loads during peak periods that drive the need for transmission and distribution investment. They state that Mr. Beach performed two detailed analyses (a marginal cost study and an embedded cost study) to support a conservative 2-cent/kWh avoided cost adder.

> The cost of service (COS) models used by TEP and UNSE allocate transmission costs based on a combination of monthly coincident peak (CP) demands and non-coincident class peak (NCP) demands in the four summer months. The COS models use NCP demands in the four summer months to allocate distribution costs. In my direct testimony, I showed that customers who add solar will see a significant reduction in the 4CP and 4NCP loads.[217]

TASC/EFCA state that Mr. Beach's 2-cent/kWh T&D adder is consistent with the APS rate case which included "an allocation within the RCP to account for avoided transmission capacity cost, avoided distribution capacity cost, and line losses in the amount of 2 cents/kWh."[218]

TASC/EFCA assert that the Companies and Staff are proposing an impossible standard for demonstrating transmission and distribution avoided costs when they argue that future transmission and distribution costs must be "known and measurable."[219] TASC/EFCA assert that "known and measurable" by its plain meaning, is an historic measure of costs and entirely inapplicable to the measurement of future avoided costs. They argue that if the Commission adopts a "known and measurable" standard for calculating future avoided costs, it would be contradicting the Value of Solar

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[213] TASC/EFCA Opening Brief at 16.
[214] Decision No. 75859 at 152. See also Tr. at 167 where Mr. Dukes stated that the Companies compared solar generation at a utility scale to distributed generation.
[215] TASC/EFCA Opening Brief at 17.
[216] Tr. at 1103-1104 Kobor testimony.
[217] Ex TASC/EFCA-P2-5 (Beach Surr.) at 18.
[218] TASC/EFCA Opening Brief at 19; See Decision No. 76295, Appendix (H) at 5 of 21, Sec. 8. TASC/EFCA acknowledge that the APS settlement is not controlling, but offer the comparison to show that the Commission has deemed a proposal that is like the one in this case to be just and reasonable.
[219] TASC/EFCA Reply Brief at 7.

Decision, which said these avoided costs should be measured.[220] TASC/EFCA state that there are well-accepted ways to measure avoided or marginal costs from DG, including transmission and distribution avoided costs based on the correlation between known and measurable historic investments in transmission and distribution infrastructure and historic peak demands. TASC/EFCA assert that it is uncontroverted that peak load growth drives infrastructure investment needs, and that DG lowers demand during system peak;[221] and it is this relationship that will necessarily lead to future avoided transmission and distribution investments. TASC/EFCA claim that no party performed a study that contradicts their avoided cost analysis.

b) Five-Year Rolling Average and Timing of Reset

TASC/EFCA claim that the Companies propose numerous deviations from the Value of Solar Decision that result in a more abrupt change to the export rate and a lower RCP rate.[222] They point to the Companies' proposal to use proxy utility-scale projects and PPAs that are outside of the timeframes adopted in the Value of Solar Decision (which mandates projects and PPAs in service within five years up to and including the test year).[223] In addition, TASC/EFCA assert that the proposal to reset the initial RCP only four months after it is set should be rejected because the Value of Solar Decision specifies annual step-downs in order to mitigate the impact of the transition from net metering.[224] TASC/EFCA also assert that the Companies' proposed first step down for the UNSE RCP rate is greater than the 10 percent annual reduction adopted in the Value of Solar Decision.[225] TASC/EFCA argue that these deviations form the Value of Solar Decision undermine the parties' ability to rely on prior Commission decisions and should not be permitted.[226]

TASC/EFCA argue that principles of statutory interpretation provide guidance in analyzing the

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[220] TASC/EFCA argue that such a standard would also conflict with the provisions of R14-2-2401 of the Energy Efficiency ("EE") Rules which prescribe that future avoided costs benefits must be calculated as part of the state's cost effectiveness test for EE measures. TASC/EFAC Reply Brief at 7.

[221] TASC/EFCA Reply Brief at 9, *citing* Tr. at 1318-19 and 1103-1104.

[222] TASC/EFCA Opening Brief at 19; TASC/EFCA Reply Brief at 10.

[223] Decision No. 75859 at 153.

[224] Decision No. 75859 at 154. "Once the formula has been set, the inputs to the formula should be updated annually to provide for more measured adjustments. We believe this will reduce the risk of dramatic changes to customers and the solar industry and is consistent with our interest in rate gradualism."

[225] TASC/EFCA Opening Brief at 20; Decision No. 75859 at 148.

[226] TASC/EFCA Reply Brief at 10.

Value of Solar Decision's directives.[227] TASC/EFCA argue that the plain language of the Value of Solar Decision is clear and unambiguous: "Staff shall use the spreadsheet described in the Decision to develop a proxy for rooftop solar generation, based on a utility's projects and PPAs with in-service dates within the five years up to and including the test year of the rate case."[228] TASC/EFCA assert this language makes no exception based on the individual circumstances of each rate case.[229] Similarly, TASC/EFCA assert that the Value of Solar Decision is clear and unambiguous that updates to the RCP will be annual, and will not exceed 10 percent annually.[230]

TASC/EFCA recommend that the Commission act now to provide some level of certainty in years 11 to 20 for new DG customers.[231] TASC/EFCA support Vote Solar's proposal to provide a transition to DG customers in year 11 by establishing a 10 percent floor on annual export compensation in years 11 through 20.[232] TASC/EFCA believe that the Vote Solar proposal is a common sense approach because it establishes a long-term decline in the rate while providing certainty to customers making investment decisions. TASC/EFCA point out that PPA prices from traditional generators reflect the developer's required payback and that the PPA pricing terms can last the life of the project. TASC/EFCA argue that the utilities should provide their customers a similar level of certainty.[233] TASC/EFCA claim that the uncertainty in the export rate in year 11 fundamentally changes the value proposition due to the expected drastic reduction in the benefits after the proposed 10-year lock-in.[234] TASC/EFCA assert that Vote Solar's proposal is prudent public policy and does not conflict with the Value of Solar Decision, which is silent on the export rate after the initial 10-year lock-in.

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[227] TASC/EFCA Reply Brief at 10. Those principles cited include fulfilling the legislative intent; if the plain language is clear and unambiguous when considered in context, not resorting to other methods of statutory construction; interpreting the law so no clause, sentence, or word is rendered superfluous or void; and in the absence of ambiguities, the entire statute must be given its complete import with the presumption that the lawmaker had a definite purpose in mind.

[228] Decision No. 75859 FoF 146 at 172.

[229] TASC/EFCA state that language in the Value of Solar Decision regarding the "last five years" is used when generally discussing the appropriateness and benefits of the RCP methodology, and when the Decision sets forth the specifics of how the methodology was to be employed, uses the language "based on the five years up to and including the test year of the rate case." TASC/EFCA Reply Brief at 11.

[230] Decision No. 75859 at 148.

[231] TASC/EFCA Opening Brief at 21.

[232] Ex Vote Solar-P2-9 (Kobor Surr) at 38.

[233] TASC/EFCA Opening Brief at 21-22; TASC/EFCA Reply Brief at 12.

[234] TASC/EFCA Reply Brief at 13, *citing* Mr. Woofenden's testimony at Tr. at 614-15; and Ex Koch-P2-1 (Koch Dir) at 2.

3. DG Meter Fee

TASC/EFCA assert that the proposed increases in TEP's DG Meter Fee, from $2.05 to $3.50 per month for residential customers, and from $0.35 to $5.62 per month for SGS customers, are dramatic and excessive. TASC/EFCA support the meter fees proposed by Vote Solar - $2.23 per month for residential customers and $0.90 per month for SGS customers.[235] They argue that the Companies did not justify their proposed meter fee, and that the proposals are in stark contrast with the direction that the Commission has already provided on the issue.[236] Citing the TEP Phase 1 Decision, TASC/EFCA argue that only incremental costs of the bidirectional meter can be included in the fee.[237] Further, TASC/EFCA assert, the proposed fees include embedded costs, which was rejected in Decision No. 75975.

TASC/EFCA also argue that the upfront payment option for the meter fee should be retained, as the one-time fee is sufficient to cover the incremental capital and labor costs of the meters.[238] Furthermore, they argue that the Companies' proposed one-time fees of $225 for Residential customers, and $315 for SGS customers, are inflated and include costs in addition to the meters. TASC/EFCA note that the DG customers are also paying the BSC, which includes costs for standard meters, meter testing, repairs and replacement.

TASC/EFCA argue that the Companies did not identify any new cost data and that nothing has changed since the Phase 1 proceeding when the Commission directed that the meter fee should be based on the incremental cost of the bidirectional meter. TASC/EFCA assert "[t]he Companies willfully neglect this mandate, simply claiming that because the meter fees apply to new DG customers, the 'marginal cost data presented in the TEP and UNSE Phase 1 proceedings provides the appropriate bases' for the meter fee."[239] They also claim that Staff has not supported its recommendation for a higher meter fee and ignores the Commission's earlier mandate. TASC/EFCA state that unlike the fees proposed by the Companies and Staff, Vote Solar's proposed fees were developed in accordance with

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[235] TASC/EFAC Reply Brief at 17.

[236] TASC/EFCA Opening Brief at 22.

[237] Decision No. 75975 at 155, "the fee should not be specified on the cost of the production meter, but on the incremental cost of the bidirectional meter that is necessary for the DG customers to receive credit for their systems' production and to receive compensation for their excess production."

[238] TASC/EFCA Opening Brief at 24.

[239] TASC'EFCA Reply Brief at 16.

Decision No. 75975, as they are based on the incremental capital and labor costs of the bidirectional meter. [240]

4. Impacts on Solar Providers

TASC/EFCA assert that the numerous changes being proposed in this docket will have profound effects on future solar customers and the businesses that service them. TASC/EFCA believe that the Commission should consider these impacts and should support gradual changes to avoid risking jobs and customers' abilities to implement DG.[241] TASC/EFCA assert that all of the Companies' proposals are abrupt and dramatic and they offer no explanation for not opting for more gradual options.[242] TASC/EFCA argue that the Value of Solar Decision addressed mitigating the cost shift with an end to net metering and declines in the export rate, but stressed that the transition should be gradual to reduce the dramatic changes to customers and the solar industry.[243]

TASC/EFCA argue that the payback periods under the Companies' proposals would be too long and render DG solar uneconomic for utility customers. TASC/EFCA's witness, Mr. Beach's discounted payback analysis showed that for both TEP and UNSE service territories, the discounted payback for a DG investment under the Companies' proposed DG rates would be more than 25 years, which is 12 years longer than the discounted payback period for solar customers under the recently approved APS rate case.[244]

TASC/EFCA assert that the Companies' simple payback analysis failed to account for significant inputs, such as a discount rate, or ongoing costs of operation and maintenance or inverter replacement. Even without these inputs, however, TASC/EFCA note that the Companies' payback analysis showed payback periods longer than ten years starting in the third year of the new rates.[245]

TASC/EFCA assert that jobs will be lost if the Companies proposals are adopted, but that gradual changes can mitigate the impact. TASC/EFCA cite the testimony of Mr. Woofenden and Mr. Koch, both of whom were concerned that if the Commission goes too far they will face layoffs or

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[240] TASC/EFCA Reply Brief at 16.
[241] TASC/EFCA Opening Brief at 25.
[242] TASC/EFCA Reply Brief at 4-5.
[243] Decision No. 75859, FoF 151 at 173.
[244] TASC/EFCA Opening Brief at 26; Ex TASC/EFCA- P2 - 5 (Beach Surr) at 14 (Tables 5a and 5b).
[245] Tr. at 155-156.

closure.[246]

5. **Residential Energy Storage**

TASC/EFCA advocate for a residential storage-friendly rate design, including a daily demand charge, be implemented. TASC/EFCA submit that the storage-friendly rate design elements that they advance align with Commission precedent, and argue that the Commission should reject the Companies' request to insert a demand ratchet into a storage-friendly rate.[247] TASC/EFCA state that they and RUCO reached consensus on the use of a daily demand charge as the key element of the storage-friendly rate.[248] TASC/EFCA state that the Commission has consistently and appropriately rejected the inclusion of demand ratchets in approving storage-friendly rates. They state that the Commission's decisions in Phase 1 of the TEP Rate Case and APS's recent rate case provide guidance:

> In Phase 1 of the TEP case the Commission found, "the demand ratchet mechanism featured in this rate design may be incompatible with battery storage technology." Indeed, it was the presence of the demand ratchet mechanism in TEP's standard LGS rate design that necessitated the formation of the LGS-TOU-S rate in the first place. The recent APS rate case decision also demonstrated the Commission's understanding of the ratchet problem. In the APS decision, the Commission approved two rates to facilitate storage, for both residential and commercial customers. The R-Tech Pilot Rate Program was made available to APS' residential and commercial customers installing several qualifying technologies, including battery storage systems, and does not include a demand ratchet. For APS' large commercial customers, the Commission stated "it would be useful to create a new, optional, non-ratcheted storage friendly rate. This new, optional rate should eliminate the demand ratchet, off-peak demand charge, and declining block demand charge currently included in APS' E-32L and E-32L TOU rate." Accordingly, the Commission directed APS to file a commercial tariff similar to the R-Tech and TEP LGS-TOU-S rates.[249]

TASC/EFCA believe that a ratchet increases investment risk substantially and unnecessarily, particularly under the 15-minute interval proposed by the Companies. TASC/EFCA state that residential customers do not have perfect foresight into their future demand needs, and that even a single increased demand event caused by a customer increasing load for a short time can eliminate up to 75 percent of their savings for the next year under a ratchet scheme. In addition, TASC/EFCA state,

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[246] TASC/EFCA Opening Brief at 27; Tr. at 584 and 649.
[247] TASC/EFCA Opening Brief at 28.
[248] Mr. Huber testified for RUCO that "I think I could certainly support a daily demand charge when it is coupled with the type of non-coincident demand charge that I just described. I think that could be a good rate." Tr. at 872.
[249] TASC/EFCA Opening Brief at 29 (citations omitted).

the ratchet creates perverse incentives, such as signaling customers to size their systems to serve less than 25 percent of peak demand, which limits both the peak reduction benefit of storage and the customer's control over their bill. They state that it would also discourage investment in any kind of increase in load, such as the purchase of an electric vehicle.[250] TASC/EFCA dismiss the Companies' hypothetical in support of demand ratchets as unrealistic and inapplicable, as well as their claim that daily battery cycling negatively impacts storage economics.[251] TASC/EFCA state that its witness, Mr. Warshay, an expert in battery storage technology, testified that battery manufacturers warrant product performance to include cycling even more frequent than once a day.[252]

Furthermore, TASC/EFCA assert that the Companies failed to demonstrate that demand ratchets reduce battery cycling because they limited their evaluation of residential storage-friendly rates to looking at large commercial rates. Mr. Warshay testified that, "due to a lack of specific analysis relating to a residential rate or demand ratchet cycling the only information available was TEP's LGST and LGSTB analysis," and "not only does their model not support their conclusion, there are several other modeling issues as well that further demonstrate that the proposed demand ratchet will not reduce battery cycling in addition to a clear misunderstanding by the utilities of storage-friendly rates and storage technology."[253] Mr. Warshay testified that the Companies' modeling was flawed because it assumed "perfect knowledge" of future building energy consumption, and employed an unrealistic approach to sizing the battery,[254] and that even on a ratcheted rate, the residential customer would have to cycle their battery daily to ensure that each new day was not the day that they set their peak.[255] Mr. Warshay also noted that most storage customers do not look at their expected peak demand and then size a battery based on the kilowatt reduction it will achieve, but rather by evaluating historical load and choosing one that will achieve the maximum return on investment against their specific rate, which was not the approach in the Companies' modeling.[256]

TASC/EFCA assert that the record supports the establishment of a residential storage rate now,

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[250] *Id.* at 30.
[251] TASC/EFCA Opening Brief at 31-32.
[252] Ex TASC/EFCA-P2-3 (Warshay Surr) at 3-4.
[253] Ex TASC/EFCA-P2-3 (Warshay Surr) at 6.
[254] Tr. at 677-78.
[255] Tr. 677.
[256] Tr. at 678.

and that the Companies' claim that the record is not sufficiently complete is misleading because it mischaracterizes TASC/EFCA's request and what the Commission has previously ordered.[257] TASC/EFCA explain that they have merely proposed certain rate design elements that they believe should be included in a residential storage rate, and not a specific tariff to be approved in the Decision. TASC/EFCA request that the Commission order the Companies to work with stakeholders to file a tariff that includes either a daily demand charge or an appropriately differentiated time-of-use rate, within 90 days of the completion of this docket.[258]

TASC/EFCA argue that the Commission should reject proposals for upfront incentives to promote the adoption of battery storage in lieu of an appropriate rate design.[259] TASC/EFCA claim that the Companies' arguments that up-front incentives are more economically efficient and avoid expensive billing system modifications are not supported by the record or Commission precedent. TASC/EFCA assert that the correct way to encourage storage deployment is not with ratepayer funded incentives to overcome flawed rate design barriers, but to remove the barrier.[260] TASC/EFCA state that in the APS case, the Commission ultimately sided with this strategy and did not adopt up-front incentives, but recognized "it would be useful to create a new, optimal, non-ratcheted rate."[261] TASC/EFCA cite the testimony of Mr. Dukes, for the Companies, in which he states that the Company has not yet looked at how a storage-friendly rate as proposed by TASC/EFCA would affect the Companies' billing system.[262] Furthermore, TASC/EFCA state, the record contains no discussion of how up-front incentives might be implemented. TASC/EFCA argue that the Companies have no adequate reason for the Commission to depart from its precedent.

6. Residential Community Solar Program

TASC/EFCA argue that the RCS program suffers from so many defects that it must be rejected. TASC/EFCA state that the RCS program is flawed because: (1) it requires subsidization; (2) it would

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[257] TASC/EFCA Reply Brief at 17.

[258] TASC/EFCA Reply Brief at 21.They urge the Commission to order the Companies to work with stakeholders and file a tariff within 90 days of the Decision in this matter that has: 1) a coincident 60-minute, on-peak daily demand charge, plus a time-of-use volumetric element, or (2) a differentiated all-volumetric time-of-use rate design, and be available to residential and small commercial customers that install a minimum 4 kWh storage system.

[259] TASC/EFCA Reply Brief at 19.

[260] TASC/EFCA Reply Brief at 19.

[261] Decision No. 76295 at 78.

[262] Tr. at 88.

not reach customers most in need of its purported benefits; and (3) it is unfair and anticompetitive with free market alternatives. First, TASC/EFCA's witness, Mr. Beach, testified that that the RCS Program requires that non-participant ratepayers subsidize program participants at a level that would be "larger than any alleged cost shift associated with customer-owned or third-party solar DG."[263] Mr. Beach explained that the subsidy results from the added expense of recovering the cost of the solar facility through TEP's rate base, and the cost of the 15 percent margin of "free electricity" that TEP would allow.[264] Mr. Beach believed that utility-owned programs like TEP's RCS and TORS will be more expensive than systems installed by third-parties by approximately $2.1 million annually or $53 million over their 25-year lives.[265] Mr. Beach's analysis indicated that the RCS Program costs would be higher than third-party solar because the monthly revenue would be less than the revenue requirement for the systems once they were added to TEP's rate base. In addition, TASC/EFCA claim that TEP did not fully account for program costs by neglecting to include costs associated with the use of its existing embedded administrative and generation resources needed to provide overhead services. Accounting for these costs, Mr. Beach found that the RCS costs are no different than those of third party solar providers.[266]

TASC/EFCA argue that the proposed 15 percent variability allowance provides program participants with incentives that third-party providers cannot offer – i.e. the option to use an additional 15 percent of historical usage for free, and to purchase additional electricity beyond the initial free 15 percent allowance at a fixed price that does not change for 25 years. They argue this position encourages less efficiency because the RCS rate is not directly related to usage.

TASC/EFCA assert that although touted as an option for customers interested in solar energy but who are unable to install panels on their own roofs, the program is unavailable to renters. They state that in TEP's Phase 1 Order, the Commission was hesitant about the RCS program absent renter inclusion, stating "we do not find that the RCS must necessarily be modified to allow for renter

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[263] Tr. at 720.
[264] Tr. at 721.
[265] Ex TASC/EFCA-P2-4 (Beach Dir) at 49; *see* TASC/EFCA Reply Brief at 21 where they argue that the Companies have ignored Mr. Beach's analysis.
[266] Ex TASC/EFCA-P2-4 (Beach Dir) at 50.

participation, but can evaluate specific proposals for expansion in Phase 2 of the Rate Case."[267] TASC/EFCA state that TEP failed to make any proposals for expanding RCS availability to renters, and bars renters because they cannot contractually commit a premises for the required 10 years of the program. TASC/EFCA state that the condition to tie the program to specific premises is not necessary because the program does not require any equipment to be installed at the residence.

TASC/EFCA argue that just because the Company has designed the RCS Program to operate in a certain fashion, doesn't mean the design should not be fixed, and if that means altering the contractual time period so that renters can participate, or altering other attributes, it should be done. TASC/EFCA assert that the Bright Tucson Program is no substitute for the RCS for renters because Bright Tucson is more expensive as it is priced at a premium. They argue that the RCS's rental exclusion sends a perplexing message to renters that if you cannot afford your own home, the utility will only allow you to access solar at a higher price than those who own their own home.[268]

Finally, TASC/EFCA argue that the RCS is anti-competitive and would be implemented at the very worst time for third party providers because the benefits of the 15 percent free allowance and 10-year locked-in rate would be offered just as the DG rate design changes and RCP rate are implemented.[269]TASC/EFCA assert that a better alternative to the RCS would be to use a competitive, free-enterprise model similar to other states where "community solar developers and potential customers are free to negotiate long-term arrangements for the development of the solar facility. Under this model TEP would receive its full delivery margin and non-bypassable costs for the delivery service that it provides from the community solar facility to its customers."[270]

TASC/EFCA argue that if approved, the RCS should not be treated as DG under the REST Rules as it is the customer siting component of the DG resources which render them "distributed." They argue that the fact that a utility-owned RCS system is located on the distribution system is not a substitute for the fact that the customer-sited requirement guaranteed customer involvement in the construction and funding of the distributed solar system. They state that utility control of a utility scale

[267] Decision No. 75815 at 35.
[268] TASC/EFCA Reply Brief at 22.
[269] TASC/EFCA Opening Brief at 38; TASC/EFCA Reply Brief at 21.
[270] Ex TASC/EFCA-P2-4 (Beach Dir) at 55-56.

system is uniquely different from customer-sited DG, and no similarity warrants a waiver from the Rules.[271] TASC/EFCA argue that if TEP is dissatisfied with the definition of "distributed solar electric generator" or "distributed renewable energy resources" the appropriate place to voice those concerns is in the open REST rulemaking docket.

7. Impact of the APS Rate Case (Response to AIC)

TASC/EFCA argue that it would be a mistake for the Commission to disregard the APS settlement not only because it considers the same issues in these proceedings, and because APS is a nearby utility, but because APS is the only utility in the country to implement an RCP rate or a GAC.[272] TASC/EFCA assert that it is common practice in rate proceedings to compare what other utilities are doing; and TASC/EFCA note that APS has had a GAC for years, and only recently raised it to \$0.93/kW. TASC/EFCA argue that there is no compelling reason to impose a dramatic increase in the GAC in Tucson, Nogales and Kingman, while customers in Phoenix, Flagstaff and Yuma enjoy a more measured and gradual implementation.[273] TASC/EFCA note further that the APS RCP includes a \$0.02/kWh adder for avoided transmission, distribution and line losses from DG. In addition, TASC/EFCA note, in the APS case future DG customers were permitted to continue to take service under the same rates as non-DG customers, which clearly demonstrates the Commission's comfort with adopting resolutions that permit DG customers to take service under other generally available rates.

F. Vote Solar

1. Resource Comparison Proxy Rate

Vote Solar recommends that the Commission adopt an initial combined export rate for both Companies of 12.4 cents per kWh, comprised of a base RCP of 9.4 cents per kWh, a 0.7 cent/kWh line loss adder, a 1.1 cent/kWh transmission adder and a 1.2 cent/kWh distribution adder. Vote Solar believes that its base RCP is conservative because it reflects more recent utility-scale prices than the Value of Solar Decision requires.[274] Vote Solar asserts that the T&D adders are consistent with the Value of Solar Decision which states that these adders should be included for utility scale prices to be

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[271] TASC/EFCA Opening Brief at 40; TASC/EFCA Reply Brief at 23.
[272] TASC/EFCA Reply Brief at 24.
[273] TASC/EFCA Reply Brief at 25.
[274] Ms. Kobor, Vote Solar's witness, testified that the evidence supports an initial export rate of 15.4 cents/kWh for TEP and 15.2 cents /kWh for UNSE.

an "accurate proxy" for rooftop solar.[275] Vote Solar asserts that the initial export rate should go into effect when the Commission issues its final decision in this case, and remain in effect for one year, as the Value of Solar Decision makes clear that the initial export rate should remain in effect for a year and then adjusted annually.[276] Vote Solar also proposed that the Commission set the RCP rate for Year 2 now because the information needed for the calculation is known. Vote Solar recommends a Year 2 RCP of 11.2 cents/kWh which is a 10 percent decrease from its initial proposed RCP.[277]

Vote Solar also recommends that the Commission explicitly adopt a 10 percent floor on the annual export rate decline after the 10-year lock-in period expires. Vote Solar states that because rooftop solar systems have useful lives of 20 to 30 years, new solar DG customers would face significant uncertainty in year 11 and beyond, and the uncertainty makes it nearly impossible for a family or small business to assess the economic viability of their investment. Vote Solar states that its proposal for years 11 and beyond will address the potential cliff, provide a minimal level of pricing certainty, and mitigate customer protection issues. Further, Vote Solar asserts, no other parties have offered any substantive arguments against the proposal.[278] Vote Solar's proposal is illustrated in the following table:

	Initial Export Rate	Second Year Export Rate
Year 1	$0.124	$0.112
Year 2	$0.124	$0.112
Year 3	$0.124	$0.112
Year 4	$0.124	$0.112
Year 5	$0.124	$0.112
Year 6	$0.124	$0.112
Year 7	$0.124	$0.112
Year 8	$0.124	$0.112
Year 9	$0.124	$0.112
Year 10	$0.124	$0.112
Year 11	$0.112	$0.100
Year 12	$0.100	$0.090
Year 13	$0.090	$0.081
Year 14	$0.081	$0.073
Year 15	$0.073	$0.066
Year 16	$0.066	$0.059
Year 17	$0.059	$0.053
Year 18	$0.053	$0.048

[275] Vote Solar Initial Brief at 3.
[276] Decision No 75859 at 148, 154.
[277] Vote Solar Initial Brief at 4; Vote Solar Reply Brief at 1-2.
[278] Vote Solar Initial Brief at 5.

Year 19	\$0.048	\$0.043
Year 20	\$0.043	\$0.039

Vote Solar asserts that its RCP rate proposal is consistent with the Value of Solar Decision and dismisses claims that an initial export rate that is above the retail rate would essentially be leaving net metering in place and be contrary to the intent of the Value of Solar Decision. First, Vote Solar claims the Value of Solar Decision says nothing about capping the export compensation rate at an amount less than the retail rate.[279] Vote Solar believes that the Commission's decision not to cap the export rate below the retail rate is significant because RUCO explicitly urged the Commission to do just that.[280] Second, Vote Solar states that the RCP proposal is a significant change to the status quo under net metering, which allows a solar customer to lock-in an export rate equal to the retail rate for 20 years (during which time the retail rate is likely to rise), with the result that even if the initial export rate is set above current retail rates, customers who install solar after this Decision will receive significantly less compensation for their exports over the life of their system.[281] Moreover, Vote Solar asserts that because the export rate will likely decrease annually, it will fall below the retail rate in a few years.[282]

a. <u>Adders</u>

Vote Solar argues that the Companies, Staff, and RUCO's opposition to Vote Solar's proposed T&D adders is based on an "unreasonably cursory and one-sided 'analysis'."[283] Vote Solar quotes the Value of Solar Decision: "In order to be an accurate proxy…[rooftop solar] should receive credit for costs that it avoids that central station solar (and other central station generation) do not avoid."[284] Vote Solar asserts that unlike the Companies, RUCO, and Staff, it meaningfully analyzed the data and calculated the avoided transmission and distribution costs; and that its proposal is a simple, conservative proxy for avoided transmission and distribution costs that is well-suited to "formulistic annual updates."[285]

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279 Vote Solar cites Staff's witness, Mr. Smith, who testified that "the utility's average retail rate does not provide either a ceiling (upper limit) on the [export] rate, nor does it provide a floor (lower limit) on the [export] rate." Ex Staff-P2-4 (Smith Surr) at 12.

280 *See* Ex Vote Solar-P2-4 (RUCO Exceptions to the Recommended Op. & Order in Docket No. E-00000J-14-0023 (November 15, 2016)).

281 Vote Solar Initial Brief at 7.

282 Vote Solar Initial Brief at 7-8.

283 Vote Solar Initial Brief at 8.

284 Decision No. 75859 at 152.

285 Vote Solar Initial Brief at 8.

Vote Solar argues that the parties opposed to the T&D adder take an overly narrow and restrictive view of the transmission and distribution capacity benefits that rooftop solar provides, and believe that rooftop solar provides no benefits unless a utility can identify specific transmission or distribution upgrades that would have occurred in the absence of rooftop solar.[286] Vote Solar agrees with TASC/EFCA witness Mr. Beach who explained that avoided transmission and distribution costs "are by definition costs that will never materialize," so it is rare for utilities to identify specific upgrades and investments that would have been made but for rooftop solar.[287] Moreover, Vote Solar asserts that "it is incorrect to assume rooftop solar provides zero benefits if the Companies do not have imminent and concrete plans to upgrade their transmission and distribution system, as small and incremental contributions to capacity provide real benefits."[288] Further, Vote Solar asserts that it is entirely appropriate to base the adders on an estimate of avoided costs, as the avoided cost benefits of rooftop solar accrue over time and into the future.[289] Vote Solar argues that by only reflecting historic and imminent avoided costs, the opposing parties exclude a significant portion of the benefits of rooftop solar, including avoided future upgrades. Vote Solar asserts that the Value of Solar Decision recognizes that a forward-looking analysis is necessary when assessing avoided costs.[290]

In addition, Vote Solar proposes that the export rate include a 0.7 cent/kWh line loss adder to reflect that rooftop solar avoids both transmission and distribution line losses.[291] Vote Solar argues that the Value of Solar Decision did not intend the line loss adder only to compare rooftop solar to utility-scale solar, but that the adder should reflect that rooftop solar avoids line losses compared to all types of centralized generation:

> In order to be an accurate proxy. . . [rooftop solar] should receive credit for costs that it avoids that central station solar (<u>and other central station generation</u>) do not avoid. As a result, the Resource Comparison Proxy . . . will require that avoided transmission, distribution capacity and <u>line losses</u>

[286] Vote Solar Reply Brief at 3.
[287] Ex TASC/EFCA-P2-5 (Beach Surr) at 21.
[288] Vote Solar Reply Brief at 3; See Decision No. 75859 at 64-65.
[289] Vote Solar Reply Brief at 3; Ms. Kobor explained that Vote Solar's transmission and distribution adders are not a precise measurement of avoided costs, but rather are estimates that "use a conservative and simple methodology well-suited to formulaic updates." Ex Vote Solar-P2-9 (Kobor Surr) at 20.
[290] Vote Solar Reply Brief at 4.
[291] Vote Solar Reply Brief at 4. The Companies and Staff believe the adder should only reflect distribution line losses because the utility-scale solar facilities connect to the distribution system.

be considered in the analysis.[292]

Vote Solar argues that the fact that most of the Companies' utility-scale solar facilities connect to the distribution system does not mean that rooftop solar avoids no transmission line losses. Vote Solar argues that regardless of whether the utility-scale solar facilities connect to the distribution or transmission system, the Companies bundle this utility-scale solar energy with other system resources for delivery to their customers, and it is unreasonable to exclude transmission line losses from the adder.[293]

b. Timing of RCP Reset

Vote Solar also argues that the Companies' proposals to reset the RCP sooner than one year violate the Value of Solar Decision as it plainly provides for annual adjustment.[294] Although the Companies have argued that these Phase 2 proceedings were unduly delayed, Vote Solar argues that the Commission knew about the status of these proceedings when it passed the Value of Solar Decision. Vote Solar asserts that the Companies expanded the scope of the Phase 2 hearing by seeking to impose a new GAC and an increase in the DG Meter Fee as well as advance a novel solar CCOSS. Vote Solar disputes the notion that the delay in these Phase 2 proceedings has given the solar industry time to adjust, as Vote Solar believes the disruptive effect of allowing multiple changes to the export rate over a short time would occur regardless of when the Commission eliminated net metering.[295] Vote Solar argues that the 10 percent limitation on the adjustment to the export rate was intended to protect against excessive pricing volatility to avoid disruptions, and Vote Solar believes the need to limit pricing volatility is important regardless of the level of the export rate.

c. Five-Year Rolling Average

Vote Solar asserts that arguments for using the most recent five years to determine the rolling average to reflect current market data ignores the fact that after the initial export rate is calculated, the subsequent annual updates would use the most current five years of market data.[296] Vote Solar argues that Staff's rationale for using post-test year data, based on the typical practice in Arizona is plainly

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[292] Decision No. 75859 at 152 (Emphasis added).
[293] Vote Solar Reply Brief at 5.
[294] Vote Solar Reply Brief at 10.
[295] Vote Solar Reply Brief at 10-11.
[296] Vote Solar Reply Brief at 13.

contrary to the Value of Solar Order. In addition, Vote Solar states that the practice of using post-test year plant to determine rate base has no connection to the task of determining the appropriate compensation for rooftop solar exports. Vote Solar notes that RUCO argues against using "gimmicks" to calculate the export rate, but uses post-test year data because RUCO believes it best reflects the intent of the Commission. Vote Solar argues, however, that RUCO's claim is undercut by the fact that the Commission rejected the Companies' request in the Value of Solar proceeding to base the initial export rate on the most recent data.[297] In response to AIC's statement that Vote Solar supports using data after the test year, Vote Solar clarifies that it does not support using utility-scale solar prices from after the test year if the initial export rate would include zero, or artificially low, transmission, distribution, and line loss adders.[298]

d. Net Metering Rules

Vote Solar argues that the Companies' export rate proposals are too low and not only violate the Value of Solar Decision, but also would violate the Commission's Net Metering Rules. Vote Solar states that the current Net Metering Rules codify net metering as a billing mechanism where a rooftop solar customer's exports to the grid may be used to offset energy provided by the utility during the applicable billing period, which means the utility compensates the solar customer for their exports at the retail rate. Vote Solar states that Staff has long held the view that modifying the export compensation rate to eliminate the one-for-one retail rate offset would not be "net metering."[299] Vote Solar states that the Commission's REST Rules and Retail Electric Competition Rules also codify retail net metering. Thus, Vote Solar argues, the Companies' proposals violate the Net Metering Rules and cannot be approved. Vote Solar states that in the Value of Solar Decision, the Commission stated it wished to eventually eliminate net metering, and approved a valuation methodology that would provide a gradual transition away from the current net metering model, but while the Commission made clear that net metering's days are numbered, the Commission's rules continue to codify and require net metering. Vote Solar argues that until the Commission amends those rules through the rulemaking

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297 Vote Solar Reply Brief at 14.
298 Vote Solar Reply Brief at 14.
299 Vote Solar Initial Brief at 9, *citing* Staff's position with respect to the Bill Credit Option in APS's Application for Approval of Net Metering Cost Shift Solution, Decision No. 74202 (December 3, 2013) at 10.

process, net metering remains the law in Arizona and the Companies' proposals are unlawful.[300] Vote Solar asserts that while the Commission has authority to issue, amend, and repeal "reasonable rules, regulations, and orders," the power is not unlimited because the Arizona Administrative Procedure Act ("APA") specifies the procedures to follow when enacting, amending, or repealing a rule.[301] Vote Solar argues that the Commission must complete a new rulemaking process before it can amend a current rule, and does not have the inherent authority to approve an export rate that conflicts with its own rules.[302] Vote Solar believes it is significant that the Net Metering Rules contain no waiver provision as contained in other Commission rules, and if the Commission had intended to allow utilities to obtain waivers from the Net Metering Rules, it would have so provided. Vote Solar argues that "[i]f the Commission could ignore or violate the net metering rules' requirements, it would have the impermissible effect of allowing the Commission to effectively 'amend or repeal' the current rules outside of a new rulemaking process."[303]

Vote Solar notes that Staff points to language in the Value of Solar Decision that suggests that the Commission anticipated that it would waive the Net Metering Rules in this proceeding. Vote Solar argues, however, that a statement in the order that "misconstrues the Commission's authority to waive the Net Metering Rules does not justify an otherwise improper waiver."[304] Vote Solar argues that "[i]f the Commission could simply issue a waiver of its current regulations in the absence of a waiver provision, it would thwart the principle of administrative law that an agency must follow its own rules and regulations; to do otherwise is unlawful."[305] In addition, Vote Solar argues that even when the Commission has plenary authority over a ratemaking issue, it must exercise that authority in a procedurally proper manner. Vote Solar asserts that because the Commission chose to enact the Net Metering Rules through an APA rulemaking, that statute prescribes how the Commission can amend

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300 Vote Solar Initial Brief at 10; Vote Solar Reply Brief at 6. Vote Solar asserts that because the Commission adopted the Net Metering Rules through an Arizona Administrative Procedure Act ("APA") rulemaking, it must complete a new rulemaking process if it wishes to amend or repeal the rules. A.R.S. §41-1001(19), (20).

301 Vote Solar Initial Brief at 11; Ariz. Const. art. XV § 3; A.R.S. § 41-1001.

302 *See Taylor v. McSwain*, 95 P.2d 415, 422 (Ariz. 1939) (agency regulations carry the force of law and are binding on the public and the agency).

303 Vote Solar Initial Brief at 12.

304 Vote Solar Reply Brief at 7. Vote Solar states that it filed exceptions in the Value of Solar docket explaining that the Commission must amend the current rules before eliminating net metering in the rate case.

305 Vote Solar Reply Brief at 7.

or repeal the rules. Vote Solar asserts that the APA states that the amendment or repeal of an existing rule is itself a "rule" that must go through a new rulemaking process.[306] Vote Solar argues that the Commission's ratemaking authority is not usurped by the requirement in the APA to complete a new rulemaking to revise the net metering policy that is codified in the current rules.[307]

e. Adherence to Value of Solar Decision

In addition, Vote Solar claims that the Companies' export rate proposals would violate the Value of Solar Decision. Vote Solar argues that the Companies, Staff, RUCO, and AIC have attempted to "collaterally attack" or "re-litigate" the Value of Solar Decision because they prefer a lower export rate. First, Vote Solar states, the proposals to re-set the export rate after less than a year violate the Value of Solar Decision's directive that the export rate should be adjusted annually.[308] Second, the export rate cannot decrease by more than 10 percent annually, but the modified Staff proposal would decrease the UNSE rate from 10.7 cents/kWh to 9.2 cents/kWh on July 1, 2018, which is a 14 percent decrease. Vote Solar argues that the Companies' rationalization that the greater than 10 percent decrease is permissible because the initial export rate would be above the retail rate, incorrectly assumes that an export rate above retail is problematic.[309] Third, Vote Solar asserts that the Commission should reject attempts by Staff, RUCO, and the Companies to skew the export rate by using a more recent five-year period than the five-year period that ends with the test year in order to lower the export rate.[310] Vote Solar argues that other parties' rationale of using more recent years to avoid "stale" data are unavailing because: (1) the Value of Solar Decision is clear and unambiguous that the five-year rolling average should include the test year and four previous years; (2) when the Commission adopted the Value of Solar Decision, it was aware of the test years for the pending rate cases; (3) the Companies made the same argument in the Value of Solar proceeding;[311] and (4) the recent decision in the APS

[306] A.R.S. §41-1001(19), (20). With respect to federal rules, the Arizona Supreme Court has found that even when an agency can amend or revoke its own rules, the existing rule has the force of law until it is modified. *Tiffany By & Through Tiffany v. Ariz. Interscholastic Ass'n, Inc.*, 726 P.2d 231, 236 (Ariz. Ct. App. 1986).

[307] Vote Solar Reply Brief at 8.

[308] Vote Solar Initial Brief at 13; Decision No. 75859 at 148, 154, 173, 177.

[309] Vote Solar Initial Brief at 14.

[310] Vote Solar cites the testimony of Mr. Smith explaining that using the five years up to and including the test year would result in an export rate of 12.4 cents for TEP and 12.8 cents for UNSE. Ex Staff-P2-2 (Smith Conf Dir) at 28.

[311] Ex Vote Solar-P2-1. The Companies' exceptions advocated for use of the most recent five-year period. (TEP & UNSE Exceptions to Recommended Opinion & Order in Docket No. E-00000J-14-0023 at 4.)

rate case settlement used the 2015 test year. Vote Solar asserts that "isolated passages" from earlier in the Value of Solar Decision does not override the clear and explicit direction provided in the Findings of Fact.[312]

Finally, Vote Solar argues that the Value of Solar Decision provides that the RCP methodology "shall also calculate the additional benefits of avoided transmission and distribution capacity and avoided line losses and those additional benefits should be added to the [RCP] analysis."[313] Vote Solar argues that the Companies', Staff's and RUCO's conclusory analysis of avoided transmission and distribution costs undercuts the Value of Solar Decision's primary mechanism for ensuring utility-scale solar prices are an accurate proxy for rooftop solar. Vote Solar claims that the Value of Solar Decision recognizes that rooftop solar does in fact provide the benefits of avoided transmission and distribution costs, and the Commission should reject attempts to assume the benefits are zero without a meaningful analysis.[314] Vote Solar states that the Companies' analysis "looked only at distribution costs, so it has no bearing on the appropriate amount of the transmission adder. And for the distribution adder, the Companies' decision to entirely dismiss distribution benefits while only focusing on distribution costs is unreasonably one-sided. As courts have recognized, it is arbitrary to only analyze one side of the cost-benefit analysis."[315] Vote Solar finds it notable that while the Companies have listed a number of "burdens" imposed by rooftop solar, they have not quantified any actual costs incurred as a result of rooftop solar.[316]

2. <u>DG Meter Fee</u>

Vote Solar recommends that the Commission refine the current DG meter fees by moderately increasing the fee for both companies to $2.33 per month for new Residential DG customers and to $0.90 per month for new SGS DG customers. Vote Solar also recommends that new solar customers have the option to pay for the meter through a one-time upfront payment, which should be $155.55 for residential customers and $62.78 for SGS customers.[317] Vote Solar's recommended meter fees are

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[312] Vote Solar Initial Brief at 17-18.
[313] Decision No. 75859 at 172.
[314] Vote Solar Initial Brief at 19-20.
[315] Vote Solar Initial Brief at 20; Tr. at 244; *High Country Conservation Advocates v. U.S Forest Serv.,* 52 F. Supp. 3d 1174, 1191 (D. Colo. 2014) (agency acts arbitrarily when it prepares "half of a cost-benefit analysis").
[316] Vote Solar Initial Brief at 20.
[317] Vote Solar Initial Brief at 21.

intended to recover the incremental capital and labor costs of the bidirectional meter, and have been updated to reflect the most recent data on capital and labor costs. Vote Solar states that the modest meter fee increase will allow the Companies to recover greater fixed costs from new solar customers – one of their goals in their rate cases. Vote Solar argues that the Commission should reject the proposals by the Companies, RUCO, and Staff to increase the meter fees by a greater amount because the larger fees would "flagrantly violate the principle of gradualism."[318] Vote Solar also argues that the Commission should reject the higher meter fee proposals because the Companies are asking the Commission to reconsider issues already decided in Phase 1 when the Commission rejected attempts to double recover various administrative costs that do not actually double when a customer installs a bidirectional meter. In addition, Vote Solar argues that the Companies' fees should be rejected because they are attempting to recover the total capital and labor costs for the bidirectional meter rather than the incremental capital and labor costs.[319] Vote Solar also opposes the elimination of the one-time upfront payment option. Without this option, Vote Solar calculates that new TEP residential solar customers would pay \$840-\$1,260 in meter fees over their system's 20 to 30-year life, and UNSE customers would pay \$720-\$1,080 in meter fees, while the incremental cost of the bidirectional meter is only \$155.55.

Vote Solar also argues that the upfront payment and the BSC are dissimilar, as the meter fee recovers the incremental costs for a specific piece of equipment that is installed at a customer's premises, while the BSC recovers numerous fixed costs, including many recurring costs. Thus, Vote Solar asserts, it is appropriate to require customers to pay a monthly BSC, while providing new solar customers the option of paying the bidirectional meter's incremental costs in one upfront payment.[320]

3. <u>CCOSS and Grid Access Charge</u>

Vote Solar argues that the Commission should not require new DG customers who select the two-part TOU rate to pay a GAC because it would violate the Net Metering Rules' procedural

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[318] Vote Solar Initial Brief at 22; Vote Solar Reply Brief at 15. The Companies, RUCO and Staff propose a \$3.50 monthly meter fee for TEP residential customers and a \$3 meter fee for UNSE residential, and a \$5.62 monthly fee for TEP's SGS customers and \$4.60 for UNSE's SGS customers. Currently, new TEP residential DG customers pay a \$2.05 monthly fee and SGS customers pay a \$0.30 monthly meter fee, and new UNSE DG customers pay a \$1.58 monthly fee.

[319] Vote Solar Initial Brief at 23-24; Vote Solar Reply Brief at 15.

[320] Vote Solar Reply Brief at 17.

requirements, is based on a flawed CCOSS, and would over-recover costs from solar customers in a discriminatory manner.[321]

Vote Solar states that the Net Metering Rules provide that if a proposed charge would increase a solar customer's costs beyond other residential or small commercial customers' costs, the charge "shall be fully supported with cost of service studies and benefit/cost analysis" and the utility "shall have the burden of proof on any proposed charge."[322] Vote Solar argues that the proposed GAC violates this procedural safeguard because it treats new solar customers differently than other customers and the Companies have not even claimed to have prepared a benefit/cost analysis.

Second, Vote Solar asserts that the GAC is based on a "severely flawed" CCOSS that unreasonably inflates the cost to serve solar customers by $6.9 million.[323] Vote Solar claims that the Companies' DG Class CCOSS modified several of the standard Base Case CCOSS key methodological foundations that should be rejected. First, Vote Solar argues that the CCOSS should allocate solar customer's costs based on delivered load, not on exports. Vote Solar states that this methodological choice triples the typical solar customer's "usage" of the grid.[324] However, according to Vote Solar, because there is sufficient capacity on the Companies' distribution systems to easily accommodate both the load and solar DG exports during both peak and low-load periods, the Companies do not incur any additional costs to accommodate the exports. Vote Solar states that "in the rare instances where a customer's decision to adopt rooftop solar does require additional equipment or costs, the interconnection process identifies those costs and the solar customer must pay for them."[325] Furthermore, Vote Solar argues, it is inappropriate to allocate costs to solar customers based on how much energy they export to the grid, and a solar CCOSS should allocate costs to solar customers in the manner that costs are allocated to other customers; that is, based on the costs that the Companies actually incur to generate and deliver energy to these customers.

Vote Solar believes that the assumption of the solar CCOSS that the Companies are providing solar customers with a service is another flaw. Vote Solar agrees with TASC/EFCA witness, Mr.

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[321] Vote Solar Initial Brief at 23.
[322] A.A.C. R14-2-2305.
[323] Vote Solar Initial Brief at 26.
[324] Vote Solar Initial Brief at 28.
[325] Vote Solar Initial Brief at 29; Ex TASC/EFCA-P2-5 (Beach Surr) at 24.

Beach, that when a solar customer exports power to the grid they are providing the Companies with a generation service, which the Companies then deliver to nearby customers who pay retail rates for that energy.[326] Vote Solar states that other types of generators and partial requirements customers who export power to the grid do not pay the Companies for this "service" and neither should rooftop solar customers. Vote Solar notes that the Companies were the only parties in this proceeding who prepared a CCOSS study that allocated costs to solar customers based on exports, rather than delivered load, and that both the Vote Solar and TASC/EFCA witnesses testified that costs should be allocated based on delivered load, and that even Mr. Huber, for RUCO, prepared a cost analysis that allocated costs based on delivered load.[327] Further, Vote Solar states that APS did not allocate costs to solar customers based on exports in their recent solar CCOSS.[328]

According to Vote Solar, another flaw is that the DG CCOSS allocates costs to solar customers based on exports in the spring rather than based on their usage during the overall Residential or SGS class NCP in the summer. Vote Solar argues that the Companies' approach is unreasonable because it does not accurately reflect how solar customers' usage contributes to distribution costs. Vote Solar notes that solar customers are often located on distribution circuits that predominantly serve residential or small commercial customers because solar customers were formerly residential or small commercial customers themselves. The NARUC Cost Allocation Manual explains that local loads are the major factors that determine the size of distribution equipment.[329] Thus, Vote Solar states, the distribution circuits serving solar customers are typically designed and built to serve the peak load of the group of residential or small commercial customers served by that circuit, and the best measure of this peak load is the residential or small commercial class's NCP. Vote Solar asserts that it is a solar customer's usage during these peak hot summer afternoons that contributes to the size and associated costs of the distribution system that the customer and nearby neighbors. Consequently, Vote Solar argues, the DG CCOSS should allocate costs to solar customers based on their usage during the residential or small commercial classes NCP.[330] According to Vote Solar, because the distribution system is built to serve

326 Vote Solar Initial Brief at 29.
327 Tr. at 859.
328 Ex Vote Solar-P2-9 (Kobor Surr) at 49.
329 Ex Vote Solar-P2-9 (Kobor Surr) at 49.
330 Vote Solar Initial Brief at 30.

the summer peak load, in the spring when the solar customers are exporting the most, there is plenty of capacity to accommodate the solar customers' exports.

The third flaw in the solar CCOSS, according to Vote Solar, is that the CCOSS is not based on actual hourly usage data from solar customers, but was based on hourly usage data from the residential class which required several analytical steps to transform that data into a solar class load profile.[331] Vote Solar states that this approach is problematic because even before installing solar, the typical solar customer has different load characteristics than the typical residential or small commercial customer.[332] Vote Solar states that as much as the Companies try to "explain and rationalize their approach, the fact remains that their DG CCOSS is based on the actual hourly usage data from a different customer class."[333] Vote Solar asserts that the Companies had sufficient time to develop the solar class load profile based on actual hourly usage data from solar customers. Moreover, Vote Solar states that the Companies do not allocate costs and design rates for other customer classes based on a different class's actual hourly usage data.

Vote Solar argues that the proposed GAC would violate the prohibition against discriminatory rate treatment prohibited by the Arizona Constitution, the Net Metering Rules, and the REST Rules.[334] Vote Solar states that the GAC is discriminatory because it requires new solar customers to pay more than their fair share of fixed costs and unreasonably increase their costs compared to other residential and small commercial customers. According to Vote Solar:

> [T]he Grid Access Charges and the Companies' other rate design proposals would over-recover $10.92 in fixed costs from the typical TEP residential customer, and $135.88 in fixed costs from the typical TEP small commercial customer, and $29.64 in fixed costs from the typical UNSE small commercial customer. This is inequitable because other residential customers pay less than their fair share of fixed costs. For example, the typical TEP residential customer currently pays 74% of their fixed costs. But if that customer adopts rooftop solar, the customer would suddenly be forced to pay 119% of their costs under the Companies' proposals.[335]

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[331] Vote Solar Initial Brief at 31-32.

[332] Ex Vote Soalr-P2-8 (Kobor Dir) at 34-37.

[333] Vote Solar Initial Brief at 32.

[334] The Arizona Constitution, art. 15 section 12 provides that utility rates shall be just and reasonable and no discrimination in charges . . . shall be made; The Net Metering Rules provide that net metering charges shall be assessed on a nondiscriminatory basis; and the REST Rules state that utilities cannot charge the solar customer any additional charges unless the same is imposed on customers in the same rate class that the solar customers would qualify for if they did not have generation equipment.

[335] Vote Solar Initial Brief at 33 (citations omitted). (Emphasis in original.)

Vote Solar urges the Commission to reject the Companies' discriminatory attempt to recover more fixed costs form solar customers than from non-solar customers. Vote Solar states that the GAC is the primary mechanism for the over-recovery and its elimination would go far to ensuring equitable rates.

Vote Solar believes that it is telling that the Companies state that by designing the GAC to create parity between the two-part and three-part rate options, the Companies are admitting that a primary purpose of the GAC is make the two-part rate so unattractive that new solar customers will consider paying a demand charge instead.[336] Vote Solar argues that the Companies' primary aim in designing the two-part rate's GAC should be to equitably and fairly recover costs from new solar customers, not to bolster adoption of the three-part rate.[337] Vote Solar claims that demand charges are problematic for residential customers – whether they have rooftop solar or not, and for solar customers they substantially harm the economics of rooftop solar even though solar customers are in no better positions to respond to demand charges than one non-DG customers.[338]

Vote Solar also argues that the Companies' claims that the GAC, and overall rate design, is conservative because it would result in a lower rate of return from solar customers is premised on their flawed DG CCOSS, which Vote Solar states over-allocated at least $6.9 million in costs to solar customers compared to the Companies' non-DG CCOSS. Vote Solar claims that RUCO and other parties have concluded that it actually costs less to serve solar customers because solar customers reduce overall usage during the hot summer peak afternoons.[339]

4. <u>Economics and Growth of Rooftop Solar</u>

Vote Solar states that if the Companies implement only one of the proposed changes to the rate design for new solar customers, it would significantly harm the economics of rooftop solar, but the combination of eliminating net metering, imposing the GAC, and increasing the DG Meter Fees, would have such a "drastic effect" on the economics of rooftop solar as to halt the growth of rooftop solar in TEP and UNSE's service areas.[340]

According to Vote Solar, the most comprehensive metric to assess a new solar rate design's

336 Vote Solar Reply Brief at 18.
337 Vote Solar Reply Brief at 15.
338 Vote Solar Reply Brief at 18-19.
339 Vote Solar Reply Brief at 19.
340 Vote Solar Initial Brief at 34.

impact is the Blended Solar Savings which reflects the value of all PV output to account for how a new rate design will impact the economics of both self-consumption and exports.[341] Vote Solar's calculations indicate that compared to the current rates and net metering, the Companies' proposals would result in a 22-45 percent reduction in solar savings available to new solar customers.[342]

Vote Solar believes that the payback period is another useful metric to analyze the impact of rate design changes. According to Vote Solar:

> ["the payback period under the Companies' proposals would be longer than ten years for every type of new solar customer, except for new UNSE residential solar customers (who would have a payback period of 9.8 years). Moreover, these payback periods are for "medium-sized" 75th percentile customers. For smaller customers, the payback periods are would be even longer. And notably, a "small-sized" 50th percentile TEP small commercial customer would <u>never</u> pay back their system under the Companies' proposals."][343] Vote Solar asserts that the testimony from the local installers, Mr. Koch and Mr. Woofenden, and Ms. Kobor's analyses, contradicts the Companies' assurances that their proposals would only modestly impact the economics and growth of rooftop solar.

Vote Solar believes it is useful to compare the Companies' proposals to the recent APS rate case in which the agreed rate design would decrease the first-year Blended Solar Savings for new APS residential solar customers by 11 percent, and agreed to keep net metering in place for small commercial customers.[344] Vote Solar states that in this proceeding, the Companies' proposals would reduce first-year Blended Solar Savings for new TEP residential customers by 20 percent, and for new SGS customers by 29 percent. Vote Solar asserts that there is no rational reason to reduce the solar savings for new residential and commercial solar customers in Tucson by more than two or three times the reduction for APS customers.

Vote Solar claims that if the President imposes a tariff on PV modules imported from China and other foreign nations, it would exacerbate the "already dire" impacts of the Companies' proposals.[345] In such case, Vote Solar states, the payback analyses performed in this proceeding will

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[341] Vote Solar Initial Brief at 34.
[342] Ex Vote Solar-P2-12 (Table 15) at 2; Ex Vote Solar P2-9 (Kobor Surr) at 81.
[343] Vote Solar Initial Brief at 35 (citations omitted).
[344] Ex Vote Solar-P2-12 (Table 14) at 2; Ex Vote Solar-P2-9 (Kobor Surr) at 79. Vote Solar Initial Brief at 36.
[345] Vote Solar Initial Brief at 36-37.

be obsolete, and the proposals' impacts on the industry will be more pronounced.

Vote Solar asserts that the Companies' narrow focus on bill savings fails to reflect how their proposals would harm the economics of solar and halt the growth by lengthening the payback periods and decreasing overall solar savings. Vote Solar notes that the Companies' analysis focuses exclusively on the bill savings that would occur under the initial 10.7 cent/kWh export rate which would only remain for a year. Vote Solar notes that the bill savings will continue to deteriorate every year as the export rate decreases.[346]

5. <u>Simplified Rate Design</u>

Vote Solar argues that new solar customers should not be subject to different tariffs than non-solar customers.[347] Vote Solar states that except for the GAC and the DG Meter Fee, the Companies' proposed solar rates are very similar to the current non-solar rates with the differences being (1) the two-part TOU rate for new solar customers has a flat delivery charge while the corresponding rate for non-solar customers has a three-tiered delivery charge; and (2) the three-part TOU rate for new solar customers has a 5 KW demand tier threshold, while the corresponding rate for the non-solar customers has a 7 kW threshold. Vote Solar urges the Commission to modify the solar rates to conform with the current non-solar rates because the two differences will unnecessarily complicate potential solar customers' efforts to calculate their solar savings and make a well-informed decision. Vote Solar argues that modifying these two features will simplify a customer's choice and be consistent with the recent APS rate case.

Further, Vote Solar asserts that new solar customers should have access to the same four tariff options that are available to non-solar customers which include non-TOU options. Vote Solar claims that Ms. Kobor's testimony demonstrated that new solar customers' fixed cost payments would be nearly identical under the two-part non-TOU rate and the two-part TOU rate, and thus, allowing new solar customers to take service under the four tariff options that were available to them before they opted to install solar, would simplify the customers' analysis without diminishing the Companies' fixed cost recovery.[348]

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[346] Vote Solar Reply Brief at 21.
[347] Vote Solar Initial Brief at 37.
[348] Vote Solar Initial Brief at 38.

6. Response to RUCO's TOG Proposal

Vote Solar generally supports RUCO's proposed TOG proposal, but has two concerns that it recommends be addressed. First, Vote Solar asserts that the TOG should only apply to new solar customer's exports and not be a buy-all, sell-all arrangement as RUCO proposes. Vote Solar states that in the Value of Solar proceeding, the Commission and every party other than RUCO agreed that for valuation and compensation purposes, solar customers' exports should be treated separately from solar energy consumed onsite because customers should have the right to reduce their energy purchases from a utility however they wish.[349] Vote Solar asserts that a buy-all, sell-all arrangement would violate the principle that a utility should not 'look behind the meter" based on a customer's technology choices.

Second, Vote Solar states that the TOG rate's time periods should match the TOU periods for the two-part TOU rate for solar customers. As currently proposed, the TOG on-peak period is 3-7 p.m. every day, including weekends and holidays, while the on-peak period for the two-part TOU rate varies by season and does not apply on weekends or holidays. Vote Solar believes that it would be simper for new solar customers to assess their rate options if both rates used the same TOU periods. Vote Solar believes that the TOG concept would best be accomplished through an optional rider that would apply to any available tariff.[350]

7. Residential Community Solar Program

Vote Solar supports expanding access to solar through community solar programs but has two concerns with the RCS program as proposed.[351] First, Vote Solar argues that the RCS program should not be limited to homeowners, but be made available to renters and owners alike. According to Vote Solar, community solar programs should be attractive to customers who are not able to install rooftop solar, among whom renters are one of the largest groups. Because the RCS program does not require TEP to install any equipment or take any actions at the participant's premises, Vote Solar sees no reason why renters should be ineligible. Second, Vote Solar opposes TEPs request to waive the REST Rules so that the RCS will count as "distributed generation" for REST compliance purposes. Vote Solar argues that the Commission should not address this policy question in this case, but should consider

349 Vote Solar Reply Brief at 22.

350 Vote Solar Reply Brief at 23.

351 Vote Solar Initial Brief at 38.

the issue in the REST rulemaking. Moreover, Vote Solar asserts that there is no need to resolve the issue now, as the Commission has freely granted waivers to TEP in the past regarding compliance with the REST DG requirements.

G. Koch

Mr. Koch is an owner of Technicians for Sustainability, and provided testimony in Phase 2 of this proceeding. He states that he intended his testimony to assist the Commission to formulate policies that would result in the continued viability of rooftop solar in TEP's service territory while reducing the cost to all ratepayers for the benefits they receive from additional rooftop solar. He asserts that the continued adoption of rooftop solar will maintain and support the cost declines and technological advancements that will provide benefits to future ratepayers, minimize stranding DG systems currently in operation, provide Tucsonans with a reasonable opportunity to reduce the environmental impacts of their energy use, and contribute to a vibrant local economy. He argues that adopting TEP's proposed plan would reduce the appeal of DG solar too far, too fast and risk collapse of the solar industry in Tucson.[352]

1. RCP

Mr. Koch asserts that the starting RCP rate for TEP should be $0.1078 per kWh, which is the average retail rate, and lower than the offset rate for most customers who adopt solar.[353] He states that this proposed rate is significantly below the rate adopted for APS, and will provide "enough value in the first few years for solar to remain a viable option for customers who do not need to finance their systems."[354] Mr. Koch states that $0.1078 per kWh is not high enough to allow for cash flow positive financing of DG systems because "even at current rates such financing generally must have a term of 15 to 20 years."[355] He states that most DG customers finance their systems with long-term loans, and adopting the current retail rate for ten years will, by itself, significantly reduce the number of installations. Further, he states that because the rate is expected to decline by 10 percent annually it is critical not to set it too low. Mr. Koch believes that adopting the export rate methodology (over net

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[352] Koch Brief at 2.
[353] *Id.*
[354] *Id.*
[355] *Id.*

metering) will significantly reduce the costs that non-participating rate payers bear to support the benefits of DG solar. He also argues that the RCP rate should remain in place for at least one year as provided in the Value of Solar Decision.

2. Grid Access Change

Mr. Koch argues that there should not be a GAC now because the move away from net metering to the RCP rate with a 10-year term, as well as the switch to TOU rates and the meter fee, will, by themselves, significantly reduce DG solar adoption rates, and anything more than a nominal fee will have a chilling effect.

He argues that if the Commission desires to adopt a GAC, such fee should not exceed $1/kW DC rate capacity and should base the calculation on the degree to which a system is avoiding costs associated with accessing the grid. He claims that a fixed fee based on rated system size does not accomplish this, as the same system installed in different configurations will avoid grid costs to different degrees, and new DG customers would be charged the fee even if their system is not producing in a month. Mr. Koch asserts that a better alternative would be to use a per kWh basis for the GAC. He states that the data for the calculation of a per kWh-based fee is already collected in TEP's meter reading process so it would be relatively easy to make monthly solar production a bill determinant.[356]

3. DG Meter Fee

Mr. Koch argues that new DG customers should retain the option to pay for the DG meter up front. He notes that if the proposed fee of $3.50 per month is adopted, over 20 years, TEP would collect $840, which Mr. Koch states is greater than the incremental cost to TEP. Mr. Koch recommends that new DG customers be allowed to pay an upfront charge of $170 for the incremental cost of the meter.

H. Plenk

Mr. Plenk is a TEP customer and participated in both phases of the TEP rate case. In Phase 2, Mr. Plenk sponsored the testimony of Mr. Woofenden, the owner of Net-Zero Solar, an installer of rooftop solar systems in TEP's service territory. Mr. Plenk asserts that TEP's proposed fixed fees for

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[356] Koch Brief at 3. He states that the average south facing solar installation produces about 153 kWh/month per kW DC, so that the conversion between the proposed fee and the actual production fee would be [a proposed fee of 4/kW DC/153 = the per kWh grid access charge; based on Staff's proposed $2.50 GAC, Mr. Koch calculates that the per kWh charge would be $0.016/kWh.

new DG customers would severely impact the DG market in Southern Arizona, and that a better approach would be to adopt principles of gradualism and move away from net metering without imposing "crippling extra charges."[357]

1. Grid Access Charge

Mr. Plenk advocates rejecting TEP's proposed \$2.50/kW DC GAC. He states that this charge is a way for TEP to bring in more revenue from DG customers regardless of usage, which he argues is not sound policy.[358] He states that the charge is a novel and bad idea, and that no witness could identify another utility besides APS that imposes such a charge (and APS's charge is less than \$1.00 per kW).[359] Mr. Plenk argues that DG customers should not have to pay an additional charge above and beyond the customer service charge in order to access the grid, and there is no evidence that owners of larger systems, who would pay more under the proposal, cause more grid expenses to justify the higher charges.[360] In addition, Mr. Plenk states that the proposed charge is not gradual as the average solar customer would incur an additional charge of \$15.75 per month in one jump (from zero currently). He asserts that when combined with the other charges, rooftop solar would become uneconomical in TEP's service territory.[361]

Mr. Plenk argues that the local solar industry and DG solar customers are an important part of Commission solar policy and "piling on" new fees and charges to make solar unaffordable is bad policy.[362] Mr. Plenk notes that the Commission recognized the importance of DG when it adopted the carve-out as part of the REST Rules, and as a result of Commission rules and market forces, a significant solar industry developed in southern Arizona providing 650 solar jobs in Pima County.[363] Mr. Plenk's witness, Mr. Woofenden, testified that based on the data of 13 customers of his own company, the payback time for solar installations under TEP's proposals would exceed ten years in 2018, and be much longer after that. In Mr. Woofenden's experience, customers do not choose to

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[357] Plenk Brief at 3.
[358] Plenk Brief at 4.
[359] Tr. at 553, 885 and 1263-1272.
[360] Plenk Brief at 5-6.
[361] Plenk Brief at 6.
[362] Plenk Brief at 6.
[363] Plenk Brief at 7; Tr. at 746-748; Ex Plenk-P2-3 (Pima County Solar Jobs Census).

install solar if the simple payback time is longer than 10 years.[364] Mr. Plenk notes that both witnesses who are directly involved in the rooftop solar market expressed great concern that the negative effects of the proposals plus external factors (changes in tax rebates, potential tariffs on solar panels) will greatly increase the cost of solar and reduce the solar savings to such an extent that rooftop solar won't be a viable option in a year or two.[365] He states that the end of traditional net metering and the planned reductions in the export rate over time is a sufficient change, and urges the Commission to reject a second meter fee and the GAC.

Mr. Plenk also supports Vote Solar's proposal to specify a 10 percent maximum drop in export rates in year 11, as customers looking at a 25-year investment need certainty.[366] He also believes that the Commission should consider payback periods in its analysis and keep payback below 10 years to maintain current solar policy.[367] He asserts that TEP's witness Bachmeier has mischaracterized and underestimated the payback periods.

Finally, he argues that the initial time frame for the RCP rate should extend for one year from implementation, not July 1, 2018, to give the program time to operate before adjustments are made.[368]

2. Data Availability

Mr. Plenk asserts that customers contemplating installing solar DG need detailed electricity usage data to determine which new TEP tariff would be most beneficial. Mr. Woofenden testified that currently, requests for such information (known as "8760 files") is cumbersome and results in delay. Mr. Plenk states that TEP agreed in principle that the information should be available, but Mr. Plenk asserts that an order is needed to insure the data is provided timely.

3. Residential Community Solar and Bright Tucson

Mr. Plenk argues that community solar programs should be open to third parties, subject to a reasonable sleeving or wheeling charge, and that the program should include renters. He asserts that the evidence in support of the fixed $19/kW rate and the 15 percent usage band is "thin," and that these aspects of the program give the utility an advantage over all other possible third-party community solar

364 Ex Plenk P2-1 (Woofenden Reb) at 11.
365 Plenk Brief at 8-9.
366 Plenk Brief at 9.
367 Plenk Brief at 10.
368 Plenk Brief at 13.

programs.[369] Mr. Plenk recommends that if adopted, the RCS should be a short-term pilot, which includes renters, and is reviewed after two or three years to determine the costs. Mr. Plenk supports exploring whether third-party community solar projects like those that have been successful in other states, or the utility-owned project, would best allow for expanded solar in TEP's territory.

Mr. Plenk also argues that the Bright Tucson premium should be cut to \$0.005/kWh. He notes that the power for this program comes from the utility's large scale solar plants which are now able to provide power for as little as 4 cents/kWh. Mr. Plenk believes that the rationale for charging a premium to cover the higher cost of solar no longer applies and that the premium should be reduced. Mr. Plenk argues that the premium should be closer to zero, but would support a reduction to ½ cent/kWh.[370]

4. RUCO's TOG proposal

Mr. Plenk supports RUCO's proposed TOG pilot program, as he believes that paying different amounts for exported electricity at different times is consistent with the Time-of-Use analysis underlying TEP's proposal for future DG customers. He states that it is fair that if these customers have two different rates for on- and off-peak power received, that the power they send to TEP should also be credited at a higher value on-peak.[371]

I. AECC

AECC represents the interests of large industrial and commercial customers. AECC participated in the Phase 2 proceedings (which focus on rate design for residential and small commercial customers) to address and minimize any inter-class cost shifts that could disadvantage or overly-burden larger users that might arise as the Commission moves away from net metering. AECC urges that the Commission adopt a cost recovery method that, at a minimum, recovers the above-market cost of the RCP rate through the REST surcharge. Furthermore, because the REST surcharge is recovered from all customers, to the extent the REST revenue requirement is increased to recover the cost of purchasing new DG exports at the RCP rate, AECC asserts that the Commission should retain the current level of class caps for non-residential classes (except the SGS class) to prevent inter-class

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[369] Plenk Brief at 12.
[370] Plenk Brief at 11.
[371] Plenk Brief at 12-13.

cost shift.[372] AECC states that the RCP pricing has a strong nexus to residential rate design and it would be inappropriate and unreasonable for costs fundamentally associated with residential rate design to be shifted to non-residential customers. Mr. Higgins testified for AECC that recovering the above-market cost of the RCP rate through the PPFAC would unreasonably allocate such costs to non-residential customers because the PPFAC is recovered from all customers based on the amount of energy consumed. In the absence of any proposal other than recovery of the entire RCP rate through the PPFAC, AECC offered a proposal that would allow TEP to recover any above-market costs associated with the RCP through the current REST surcharge. AECC believes that this recovery method is consistent with how TEP currently recovers the above-market cost of utility-scale renewable energy.[373] AECC states that no party disagreed with its proposal, and that witnesses for TEP, Staff, and AIC agreed that AECC's proposal is reasonable and consistent with current practice.[374]

AECC argues that retaining current REST surcharge caps for non-residential customers can further mitigate the cost shifts associated with TEP's residential DG program.[375] AECC clarified that it is not proposing a blanket prohibition against raising the current level of class caps on the REST surcharge, but asserts that because the RCP rate on new DG exports benefits only participating customers in the eligible Residential and SGS customer classes, TEP should not be permitted to raise the current level of REST caps on non-eligible customers for the benefit of those classes eligible to participate in the program.

In its Reply Brief, AECC proposed specific modifying language to be included in the RCP Plan of Administration as follows:

Option 1 adds a new Section 10, at page 6 to limit recovery of costs associated with the purchase of export energy from residential and small commercial customers to only those eligible customers:

> "10. **Cost Recovery**
> All costs related to the Company's purchase of Exported Energy, at the price included in the Rate Rider RCP, shall be recovered only from those Customers eligible to receive bill credits under Section 4 (Customer Billing) of this Plan of Administration."

Option 2 adopts AECC's proposal to allow TEP to recover the market cost of exported energy

[372] AECC Brief at 2-3.
[373] AECC Brief at 4.
[374] Tr. at 91, 468, 1161.
[375] AECC Brief at 5.

through its PPFAC, and the above-market cost of export energy through its REST surcharge:

> "10. **Cost Recovery**
> The market cost related to the Company's purchase of Exported Energy, at the price included in the Rate Rider RCP, shall be recovered through the Company's Purchased Power and Fuel Adjustor Clause at the then existing Market Cost of Comparable Conventional Generation ("MCCCG). All above-market costs for the purchase of Exported Energy shall be recovered by the Company through its existing Renewable Energy Standard Tariff (REST) surcharge."

J. Staff

1. CCOSS and Rate Design

Staff accepts the Companies' CCOSS.[376] Staff notes that in its Rejoinder testimony the Company modified its position on rate design and reduced their request for the DG Meter Fee for new DG customers to Staff's recommended charge.[377] Staff and TEP and UNSE agree on the Companies' proposed rate designs for new DG residential and SGS customers.[378]

a) Grid Access Charge

Staff states that a GAC is designed to recover some of the fixed costs related to generation, transmission, and distribution that the Companies incur to serve DG customers, but which customers avoid due to the recovery of fixed costs through volumetric rates. Staff states that DG customers use the grid continuously to receive electricity, to transmit their extra solar generation to the grid, and for ancillary services such as frequency control and voltage support.[379] Thus, according to Staff, it is appropriate for DG customers to pay for the fixed costs of the grid.

In response to criticisms from Vote Solar and TASC/EFCA, Staff argues that the GAC does not violate A.A.C. R14-2-2305 of the Net Metering Rules because it has been determined that DG customers are in a different rate class and have different load characteristic, thus A.A.C. R14-2-2305 would not be triggered by implementing a GAC.[380] In addition, Staff states that new DG customers

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[376] Staff's Opening Brief at 5; (Tr. at 1193.)
[377] Ex TEP/UNSE-P2-6 (Dukes RJ) at 5; Staff Opening Brief at 5.
[378] Staff opening Brief at 6-8.
[379] Staff Opening Brief at 9.
[380] A.A.C. R14-2-2305 provides in part: "Net Metering charges shall be assessed on a nondiscriminatory basis. Any proposed change that would increase a Net Metering Customer's costs beyond those of other customers with similar load characteristics or customers in the same rate class that the Net Metering Customer would qualify for if not participating in Net Metering shall be filed by the Electric Utility with the Commission for consideration and approval. The charges shall be fully supported with cost of service studies and benefit/cost analysis. The Electric Utility shall have the burden of proof on any proposed change."

who adopt DG after the Phase 2 Decisions will not fall under the Net Metering Rules, and thus not be subject to this provision.[381]

Staff also argues that the CCOSS is not flawed as claimed by Vote Solar and TASC/EFCA. Staff states that the Value of Solar Decision determined that DG customers are a separate customer class and that the Commission is committed to modifying residential rate design in a manner that mitigates the cost shift caused by rooftop solar customers' self-consumption.[382] Staff asserts that the GAC is intended to do just that. Staff asserted:

> The CCOSS performed by the Companies comports with the Commission's mandate in the Value of DG Decision 75859 to prepare a CCOSS for the DG residential class. Further, the Commission was clear that it did not approve a specific CCOSS methodology. While it is understandable that these parties believe the CCOSS should be based on the load delivered to the DG customer, because this results in fewer costs being allocated to those customers for recovery, here it has been demonstrated that the Companies are not recovering close to all of the fixed costs allocated to these customers due to reduced usage. The fundamental problem is the Companies still must serve those customers in the event the rooftop solar ceases functioning or the sun is not shining. In other words, the amount of fixed costs associated with servicing those customers still exists even though those customers use less electricity, and the Companies should be given the opportunity to recover those costs.[383]

Staff asserts that the Companies' CCOSS for DG customers is identical to that for non-DG customers except for the NCP and CP determination, with the DG Class NCP based on the maximum use of the distribution system for either consumption or export. Staff states that the "use of the import and export capacity requirements is essential for partial requirements customers in order to incorporate the maximum burden they place on the system."[384]

b) **<u>DG Meter Charges</u>**

Staff agrees with the concept that there are additional incremental meter costs associated with providing service to DG customers, including the need and cost for two meters--a bidirectional meter that records flows of power from and to the grid, and a production meter that records the amount of generation produced by the solar panels to comply with the REST Rules. Staff states that the CCOSS supports a DG meter charge of $8.62 for TEP residential customers, $9.13 for TEP SGS customers,

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[381] Staff Reply Brief at 9.

[382] *Citing* Decision No. 75859 at 174 and 176.

[383] Staff Reply Brief at 10.

[384] Staff Reply Brief at 10 citing Tr. at (1192-1120.)

$9.54 for UNSE residential customers, and $12.60 for UNSE SGS customers.[385] Staff originally proposed a meter charge of $4.32, but revised its position in Surrebuttal Testimony and recommended a meter charge of $3.50 for TEP residential customers and $5.32 for TEP SGS customers, and $3.00 for UNSE residential customers and $4.60 for UNSE SGS customers. In Rejoinder Testimony, the Companies agreed to Staff's recommended charges.[386] Staff believes that approving its recommendation on meter fees, that are below the cost of service, comports with the concept of gradualism, while still allowing the Companies to recover some of their costs through these fees.

Staff states that it would not oppose an upfront meter charge, but asserts that the upfront payment option must be adequate to cover the full costs of the new meter, and it would be necessary to clarify who would be responsible for paying for maintenance and any potential replacement meter.[387]

2. Residential Community Solar and Bright Tucson

Staff supports TEP's proposed RCS program and agrees with the concept of a flat monthly rate for the program.[388] Staff states that although it had recommended that the rate be cost-based, it recognizes that there are other ways to set the rate for the program, and "in light of the reasons presented by TEP for using a flat rate, Staff has accepted a flat rate as a reasonable way of implementing the program, but disagrees with TEP's suggested rate."[389] Staff continues to recommend a cost-based rate.[390] Staff recommends that if the Commission approves the $19.00 per kW rate, the Company should be required to provide cost data for the RCS facility so that a cost-based rate for the RCS program can be developed in TEP's next rate case.[391]

Staff agrees with TEP's assertions concerning the Bright Tucson program and supports the proposed reduction in the premium to $0.01 per kWh.[392]

3. Resource Comparison Proxy Rate

Staff recommends separate DG export rates of 12.8 cents per kWh for UNSE, and 10.5 cents

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[385] Staff Reply Brief at 8.
[386] Staff Opening Brief at 10; Staff Reply Brief at 8; Ex TEP/UNSE-P2-6 at 5 (Dukes RJ).
[387] Staff Opening Brief at 11; Tr. at 1259.
[388] Staff Opening Brief at 15.
[389] Staff Opening Brief at 15; Ex Staff-P2-3 at 39 (Smith Dir Rate Design) at 39.
[390] Staff Opening Brief at 15.
[391] Staff Opening Brief at 15.; Staff Reply Brief at 11.
[392] Staff Opening Brief at 16.

per kWh for TEP.[393] However, Staff states that it would not object to a combined rate for TEP and UNSE of 10.7 cents per kWh.[394] If the Commission adopts a combined RCP rate for TEP and UNSE, Staff recommends that the initial rate of 10.7 cents per kWh, be reset on July 1, 2018, to 9.63 cents per kWh for TEP and to 9.20 cents per kWh for UNSE.

Staff recommends separate RCP rates for the Companies because: (1) UNSE and TEP are separate companies; (2) they each have their own specifically identified PPAs and utility-owned grid-scale solar facilities; (3) although their Phase 2 cases are being heard together, they are not consolidated and each company has its own rate case; (4) TEP and UNSE have different cost structures, cost of capital and depreciation rates; (5) TEP and UNSE have different service territories; (6) they each have a different cost of service; and (7) they have separate and distinct rates.[395] Although Staff's primary recommendation is for separate rates, it does not oppose a combined RCP for both Companies for the reasons enumerated by the Companies.[396]

Staff states that both TASC/EFCA and Vote Solar focus on payback periods and argue for gradualism in approving new rates for DG customers on the belief that the Companies' proposals will negatively impact rooftop solar installations. Staff states that, it too, considered the interplay between the RCP and the payback period, as customers contemplating installing rooftop solar systems consider the economics and evaluate the decision based on the number of years that the net savings in energy costs would take to recoup their investment. Staff recommends that the payback period information be considered, in conjunction with other information in making the decision on the RCP rate, and that the Commission should balance "the reduction of the cost shifts with the need to present opportunities for economically viable distributed solar installations."[397]

Staff asserts that the Companies' proposal to reset the UNSE rate to 9.20 cents/kWh on July 1, 2018, violates the clear directive in the Value of Solar Decision that reductions in the compensation rate should not exceed 10 percent annually.[398] Further, Staff asserts that nothing in the Value of Solar

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[393] Staff Opening Brief at 18.
[394] Id.; Ex Staff-P2-4 (Smith Surr) at 10.
[395] Staff Opening Brief at 23; Ex Staff-P2-4 (Smith Surr) at 9.
[396] Id. at 23-24; Ex TEP/UNSE-P2-2 (Tilghman Reb) at 7.
[397] Staff Opening Brief at 6.
[398] Decision No. 75859 at 148; Staff Opening Brief at 19.

Decision prohibits setting an initial RCP rate above the average retail rate. Consequently, Staff argues that if the Commission adopts a combined rate for the Companies, it should adopt a rate of 10.7 cents per kWh for the first year, with a July 1, 2018, reset to 9.63 cents per kwh for both Companies.[399]

Additionally, Staff argues that the RCP rate should be calculated using the five years through the end of the test year.[400] Staff acknowledges that there may be some ambiguity in the Value of Solar Decision regarding the appropriate five-year period to use to calculate the RCP rate, but believes that it is a reasonable interpretation that the RCP is set using the five years through the end of the test year.[401]

In response to criticisms from the Companies and RUCO concerning Staff's use of a five-year period that includes four years and an additional 12 months beyond the test year to calculate the RCP rate, Staff believes that the Value of Solar Decision is clear that the information to be used is the five-year period through the test year. Staff states that it originally used that time period, but revised its recommendation to include the 12 months beyond the test year because it is typical for the Commission to recognize that time period in setting rates. Staff believes that using the 12 months beyond the test year is reasonable under the specific facts in this case.[402]

Staff also relied on that portion of the Value of Solar Decision that provides:

> Staff shall use the spreadsheet described in this Decision to develop a proxy for rooftop solar generation based on a utility's projects and PPAs with in-service dates within five years up to and including the test year of the rate case. *If projects of recent vintage are not available for the utility*, Staff shall use pricing data form available industry sources for grid-scale solar PV projects, with priority given to projects in Arizona to the extent available.[403]

Staff interprets the above provision to mean that the Commission "would only look to industry sources in the event the Companies have no projects or PPAs with in-service dates within the five-year period."[404] Staff states that because each of the Companies had specifically identifiable PPAs and other

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[399] Staff Opening Brief at 19.
[400] Staff Opening Brief at 19.
[401] Specifically, Staff relied on the provision in Decision No. 75859 that provides that "Staff shall use the…spreadsheet to develop a proxy for rooftop solar generation, based on the utility's projects and PPAs with in-serve dates within the five years up to and including the rest year of the rate case."
[402] Staff Reply Brief at 4.
[403] Decision No. 75859 at 172. (Emphasis added)
[404] Staff Opening Brief at 22.

solar facilities with in-service dates during the five-year period, it was not necessary to use industry resources even though there were years when UNSE did not have any new PPAs or utility-owned solar facilities added.[405]

Staff acknowledges that the Value of Solar Decision is not clear about how to calculate the RCP when there are no new PPAs or projects added in each of the five-years, but asserts that resorting to industry market data could have a negative impact on the RCP rate. Staff notes that no party disputed the concept of energy-based weighting, but it is unclear how industry information would be weighted, and it has the potential of "dwarfing the other projects of a smaller utility such as UNSE."[406] Staff asserts that the parties' recommendations (or at least willingness to accept) a combined RCP rate addresses the problem in this case.[407] Staff believes the matter should be addressed further in the ongoing rulemaking that is studying changes to the Net Metering Rules in light of the Value of Solar Decision.

With respect to the issue of adders to the RCP rate for transmission and distribution avoided capacity and line losses, Staff looked to the directive in the Value of Solar Decision that provides that avoided transmission, distribution capacity and line losses be considered in the analysis.[408] Staff notes, however, that the Value of Solar Decision does not establish the methodologies to determine if an adjustment to the RCP by means of these adders is warranted.[409] Staff states that it, along with RUCO and the Companies, recommend an avoided line loss adder of 3.53 percent, but do not recommend adders for avoided transmission and distribution costs. Staff criticizes the methodologies employed by Vote Solar and TASC/EFCA to arrive at their recommended T&D adders because neither methodology demonstrates that either Company actually avoided any investment in transmission or distribution facilities.[410] Staff agrees with the Companies' criticisms that the Vote Solar and TASC/EFCA

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[405] Staff believes that Vote Solar and TASC/EFCA also interpreted the provision in the same manner. Staff opening Brief at 22. Ex Vote Solar-P2-9 (Kobor Surr) at 25; Ex TASC/EFCA-P2-5 (Beach Surr) at 36-37.

[406] Staff Opening Brief at 22.

[407] *Id.*

[408] *Id.* at 153.

[409] Staff Opening Brief at 24.

[410] Staff Opening Brief at 26. Staff states that Vote Solar used the average embedded cost per kWh related to distribution and transmission based on the revenue requirements identified in the CCOSS, and dividing the total approved revenue requirement for each category by the retail kWh sold; and that TASC/EFCA utilized a marginal cost analysis. Ex Vote Soalr-P2-8 (Kobor Dir) at 19; Ex TASC/EFCA-P2-4 (Beach Dir) at 38.

methodologies cannot support quantification of avoided transmission and distribution costs because marginal costs for added load cannot equal the avoided cost for reduced load as: (1) sunk costs for distribution plant already in service are not reduced by reduction in load; (2) to have a large enough peak load reduction to allow for a smaller set of delivery assets requires more installed DG capacity than the load carrying capability of the smaller assets; and (3) for "as available" DG resources the only avoided cost that is permitted under FERC regulation is the avoided cost at the time of delivery, which means that long-run marginal avoided costs are not permitted to determine avoided costs.[411] Staff also cites RUCO's testimony that for there to be a true avoided cost, the DG solar production must be located on a circuit where there is a capacity need, perfectly timed to coincide with the capacity need, and displacing all of the capacity need.[412] Staff asserts that no party performed such an analysis in this case, and Staff does not believe that there is anything in the records of these cases to justify anything other than a zero adder.

Staff acknowledges that the Value of Solar Decision directs that avoided transmission and distribution cost be considered in the analysis of developing an RCP rate, but argues that "consideration" is not synonymous with "inclusion." Staff argues that TASC/EFCA are mistaken in believing that avoided transmission and distribution costs refers to future costs, and not costs that have been avoided. Staff states that the Value of Solar Decision does not require including transmission and distribution capacity costs that will be avoided, but rather clearly requires that avoided transmission and distribution and line losses costs (past tense) be considered in the analysis.[413] Staff asserts that it is impossible to include costs that have not been proven to have been avoided, and that the problem with the methodology used by TASC/EFCA and Vote Solar is that there is no cause and effect demonstrating the actual avoidance of these costs, which means that the avoided costs are speculative.[414]

Staff recommends the 3.53 percent line loss adder developed by the Companies. Staff believes that it is appropriate to exclude transmission level line losses because all the projects for these Companies reside on their respective distribution systems and transmission system losses are not

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[411] Ex TEP/UNSE-P2-6 (Tilghman Reb) at 15-16.
[412] Staff Opening Brief at 26, citing Ex RUCO-P2-2 (Huber Surr) at 14.
[413] Staff Reply Brief at 5.
[414] Tr. at 1206; Staff Reply Brief at 5.

avoided with DG solar generation relative to utility scale solar generation.[415]

Staff believes that its recommendations are the most balanced and best comply with the spirit of the Value of Solar Decision. [416] Staff asserts that its recommendations are based on a reasonable interpretation of the Value of Solar Decision and that the Phase 2 proceedings took much longer than contemplated by that Decision. Staff acknowledges that RUCO, Vote Solar, and TASC/EFCA are correct that the Value of Solar Decision did not contemplate the export rate would be reset sooner than a year, but that at the time the Value of Solar Decision was adopted, it was not contemplated that the Phase 2 would be unduly delayed.[417] As a result of the delay, the grandfathering period was extended, and additional customers have been able to avail themselves of net metering for a longer period. Because of the unique circumstances affecting the procedural posture of these cases, Staff believes that its recommended deviation from the directive to reset the export rate annually is appropriate.[418]

In response to Vote Solar and TASC/EFCA's urging to provide certainty in years 11 through 20, Staff states that these parties advocated for a 20-year lock-in period in the Value of Solar docket, and filed exceptions addressing that issue, but that the Commission unequivocally adopted a 10-year lock-in period.[419] Staff asserts that it is inappropriate for these parties to continue to litigate this issue.

4. <u>Value of Solar Decision and Net Metering Rules</u>

In response to Vote Solar's assertions that the Commission is required to abide by its Net Metering Rules until they are amended, and cannot implement the methodologies adopted in the Value of Solar Decision, Staff argues that the Commission has the authority to waive those rules when in the public interest, and that it recognized in the Value of Solar Decision that waivers to the Net Metering Rules may be granted in these Phase 2 proceedings.[420] Staff argues that the Commission's rulemaking authority is plenary, pursuant to authority granted in Article XV, Section 3 of the Arizona Constitution, and that it is incorrect to conclude that the Commission's plenary ratemaking authority is curtailed by

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[415] Staff Opening Brief at 27.

[416] Staff Reply Brief at 2.

[417] Staff notes that the Value of Solar Decision ordered the Hearing Division to promptly issue any necessary Procedural Orders regarding incorporating the RCP methodology, and although the Procedural Orders were promptly issued, the Phase 2 proceedings for these Companies were scheduled after the rate case of APS was expected to be concluded with a hearing date of June 26, 2017. The proceedings were further delayed when the parties pursued settlement discussions.

[418] Staff Reply Brief at 3.

[419] Staff Reply Brief at 5

[420] Decision No. 75859 at 179.

the creation of the Net Metering Rules. Further, Staff argues it is unreasonable to conclude that the Commission is precluded from implementing the methodologies set forth in the Value of Solar Decision when the Commission specifically determined a path forward to resolve disputes surrounding the successful integration of DG with the utility's electrical systems in an economic and fair manner.[421]

In response to arguments that the Commission cannot transition away from net metering without first repealing the Net Metering Rules, and that the Commission does not have the inherent authority to waive the current Net Metering Rules, Staff argues that the Commission is not like agencies in most other states as it "is not a creature of the legislature, but a constitutional body which owes its existence in the organic law of this state."[422] Staff argues that the Commission has full and exclusive power to set "just and reasonable rates." The powers and duties of the Commission are described in Article 15, §3 of the Arizona Constitution:

> The corporation commission shall have full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the state for service rendered therein, and make reasonable rules, regulations and orders, by which such corporations shall be governed in the transaction of business within the state[.]

The Arizona Supreme Court has found:

> [I]n the matter of prescribing classifications, rates and charges for public service corporations and in making rules, regulations, and orders concerning such classifications, rates and charges by which public service corporations are to be governed, the Corporation Commission has full and exclusive power. In such field, the Commission is supreme and such exclusive field may not be invaded by the courts, the legislature, or the executive.[423]

Staff believes the case of *Arizona Corporation Commission v. Palm Springs* is particularly instructive as the Arizona Court of Appeals recognized that the Commission might accomplish some goals using rules and regulations of general applicability, and other goals by using orders pertaining to specialized situations or to particular public service corporations.[424] Staff argues that in the current situation the Commission has determined that there is a cost shift between DG customers and non-DG

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[421] Staff Opening Brief at 29; Decision No. 75859 at 143.

[422] *Ethington v. Wright*, 66 Ariz. 382, 389 (1948); *See* Ariz. Const. art. 15 ("The Corporation Commission"), §§ 1-19.

[423] *Ethington*, 66 Ariz. at 392, 189 P.2d at 216; *see also State v. Tucson Gas, Electric Light & Power Co.*, 15 Ariz. 294, 306 (1914).

[424] *Arizona Corp. Comm'n v. Palm Springs Util. Co., Inc.*, 24 Ariz. App. 124, 128 (1975); Staff Reply Brief at 6.

customers that needs to be addressed, and that while it is clear the Commission ultimately intends to amend the existing Net Metering Rules, the Commission has the necessary authority to waive the rules if it determines that the rules no longer function as originally intended.[425] Staff argues that Vote Solar's position that despite the harm that will occur by the continued application of the Net Metering Rules, the Commission is precluded from remedying the harm until a formal rulemaking can be completed, is untenable and not in line with the Commission's rate making authority.

Staff argues that by failing to ameliorate a harm that it identified in the Value of Solar Decision, the Commission would abdicate its obligations under Article XV, Section 3 of the Constitution. Staff states that the Commission certainly has the ratemaking authority to suspend or waive rules that it promulgated pursuant to that authority if it determines that these rules are no longer functioning in the public interest.[426] Staff states that the Commission has determined that net metering fails to mitigate the cost shift between DG and Non-DG customers and the absence of a "waiver" provision does not prevent the Commission from balancing the public interest.

III. Analysis and Conclusions

F. Cost of Service Study and Rate Design

TEP and UNSE revised the CCOSSs utilized in Phase 1 of their rate cases to reflect approvals in those earlier proceedings and to create a separate partial requirements class for the Residential and SGS DG customers. Staff and RUCO have accepted the Companies' CCOSSs, and the Companies, Staff, RUCO, and AIC agree on the proposed rate design for DG customers. For both the Residential and SGS DG Classes, TEP proposes two rate options—a two-part TOU rate, with a GAC of $2.50 per kW-DC and a three-part rate with a demand charge of $8.85/kW for the first 5 KW, and $12.85/KW for demand greater than 5 kW for residential DG customers, and $9.95/KW for the first 5 kW, and $13.95 per kW for demand greater than 5 kW for the SGS DG customers. Both rate options also contain a DG meter charge of $3.50 for residential DG customers and $5.62 for the SGS DG customers.

Vote Solar and TASC/EFCA criticize the provisions of the Companies' CCOSSs that allocate costs to the DG classes based on electricity exported from customers to the grid as well as the delivery

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[425] Staff Reply Brief at 7.
[426] Staff Reply Brief at 7.

of electricity to customers from the utilities. These parties testified that this methodology over-allocates costs to the DG partial requirements classes. They oppose the proposed rate design for including an inflated meter fee, imposing a GAC that they consider much too large, and not providing the same rate design options to the DG partial requirements class as are provided to the non-DG full-requirements Residential and SGS customers (who have non-TOU options).

1. CCOSS

Cost causation is the primary consideration for allocating costs. The cost driver for the distribution system is capacity. Distribution circuit capacity is required for both delivery of energy to the customer and export of energy from the customer. Therefore, distribution circuits must be built to accommodate the combined maximum demand capacity for delivery and export usage. If DG export production occurs during the combined DG and non-DG NCP, it is appropriate and reasonable to include that usage of the grid for export or import in the allocation of costs because it impacts distribution system capacity. Thus, arguments by Vote Solar and TASC/EFCA that DG export production should not be a basis for allocating distribution costs are invalid.

The argument by Vote Solar and TASC/EFCA that DG solar exports should not be treated differently than power acquired from merchant generators who do not pay to access the grid does not recognize that merchant generators do not impact the distribution system in the same manner as rooftop generators. Merchant generators are indifferent as to the customers who use the power they sell and although the power they sell is a cost, the merchant generators themselves, are not cost causers. It is use of the distribution circuit by utility customers to either import or export power that creates the need for investment in distribution capacity. DG customers, like any utility retail customer, depend on the grid – they happen to depend on it for both the import or export of power.

Residential and SGS DG customers differ from merchant generators in other ways as well. They are scattered randomly on distribution circuits, they are permitted to sell their excess DG production at prices above market for solar energy, and their exported DG production must be taken by the utility when it is produced giving the utility no control over dispatch. If not for the grid that is paid for by all customers, rooftop DG would have no facilities to deliver their excess production.

The Companies utilized the class NCP method which determined the NCP for the non-DG and

DG classes separately to allocate the distribution costs between DG and non-DG customers. However, usage of the grid during times other than the net combined NCP of the DG and non-DG classes should not be factored into the allocation of the distribution costs as it does not drive distribution capacity costs. Since the combined NCP for the DG and non-DG customer classes occurs in the summer, the DG class NCP, based on exports in April, does not impact the cost of the distribution circuit as there is plenty of excess capacity at that time.

The following example illustrates a more equitable cost allocation between non-DG residential customers and DG residential customers; based on their net maximum combined usage. Assume the following: a total distribution circuit cost of $1,000,000; 100 total residential customers, of which 95 are non-DG and 5 are DG; a production capacity for each DG customer of 6 kW; the NCP for the net combined residential usage occurs in July; the NCP for non-DG customers occurs in July; the NCP for DG customers occurs in April; each of the non-DG customers has a peak load demand in July of 6 kW, and each DG residential customer has a peak load demand in July of 7 kW; and each of the non-DG and DG residential customers has a peak load demand in April of 2 kW. In this example, in July, DG customers' demand (7 kW) is greater than their export capacity of 6 kW, resulting in a 1 kW net demand. In April, the DG customers' production remains at 6 kW but their load demand declines to 2 kW allowing for export of 4 kW of excess energy onto the distribution circuit. Non-DG customers have a demand of 6 kW in July and 2 kW in April. For DG customers as a class, the July peak demand is 5 kW (1 kW x 5) and the April peak demand is 20 (4 kW x 5), the latter being the NCP for the DG class. For Non-DG customers, the July NCP is 570 kW (6 kW x 95) and the April peak demand is 180 kW (2 kW x 95). The maximum residential demand on the circuit is 575 kW (6 kW x 95 non-DG customers + 1 kW x 5 DG customers) and occurs in July. In April, the maximum demand on the circuit by residential customers is 210 kW (2 kW x 95 non-DG customers + 4 kW x 5 DG customers). Because the net combined residential NCP occurs in July, this is the basis for allocating the distribution circuit costs, and it is irrelevant that the DG customers' NCP occurs in April because the circuit must be built to serve the maximum total residential capacity which occurs in July. No additional cost is incurred to serve the DG customers' NCP.

Since the usage on the system during the net residential NCP is 5 kW for DG customers and

570 kW for non-DG customers, the respective cost allocations are \$8,696 (5/575 x \$1,000,000) for the DG class and \$991,304 (570/575 x \$1,000,000) for the non-DG class. The NCP method used by the Companies would allocate \$33,898 (20/(570 + 20) x \$1,000,000) to the DG class, and \$966,102 (570/(570 + 20) x \$1,000,000) to the non-DG class. In this example, the amount of the distribution cost allocated to DG customers increased by \$25,202, from \$8,696 to \$33,898 due to the Companies' allocation method compared to the net combined residential NCP method discussed above. This example shows that use of the class NCP method can yield very different results from the more equitable net combined Residential NCP method.

We agree with the Companies that both load demand and export energy production have the potential to be the constraining factor on the demand capacity of a distribution circuit. Accordingly, depending on the circumstances, either may be the appropriate factor for allocating distribution costs between the DG and non-DG customer classes. However. the Companies' use of the separate class NCP demands instead of the relative demands each class places on the distribution system at the time of their combined maximum demand, does not attribute the cost of the distribution system in proportion to cost causation between the DG and non-DG classes, and thus, it is inequitable. The potential impact could be, and likely is, significant, but we cannot know the full effect until the Companies revise their CCOSSs to reflect a more equitable allocation based on the relative demands of each class at the time of their combined maximum demand.

2. Rate Design

We cannot approve the Companies' proposed rates. The Companies must revise the CCOSS, as discussed above, for the Commission to evaluate the proposed rates. Absent a revised CCOSS that equitably allocates costs, we cannot determine if the rates of return of the various classes are equitable under the proposed rates. If the CCOSS as presented by the Companies over-allocates costs to the DG partial requirements classes, the Companies' proposed rates would yield a higher rate of return for the DG classes than reported by the Companies. We look to the rates of return for the various customer classes to determine if there are inter-class subsidies. Although the existence of subsidies does not automatically disqualify rates from being just and reasonable, the subsidies must be transparent for the Commission to make an informed decision.

Since the beginning of the REST Rules and net metering, the Companies' customers have been subsidizing the implementation of renewable resources. The Commission knowingly approved net metering and the REST surcharge to incentivize the adoption of more renewable resources. As we acknowledged in the Value of Solar Decision, the time has come to move away from rate structures under which non-DG customers pay more than they need to in order to support DG. However, it is not appropriate that the DG customers pay more than their fair share of distribution capacity costs. The rates for the DG classes should yield rates of return roughly equivalent to those of the non-DG classes.

Thus, TEP and UNSE must submit revised CCOSSs, and if the revised CCOSS indicates that the rates of return for the new partial requirements DG Residential and SGS Classes with the Companies' proposed rates are greater than the rates of return for the corresponding non-DG Classes, the Companies should propose new rates for the DG classes to produce rates of return between the DG and non-DG classes that are substantially equivalent without changing the rate structures, i.e., the BSC should remain unchanged, but the energy and demand charges should be adjusted to maintain the same approximate relationships as the non-DG rates.[427]

In the interim, until the Companies submit revised CCOSSs and new DG rate options for approval by the Commission, new residential and SGS DG customers who submit an application to interconnect after the effective date of this Decision may take service under any of the TOU rate options available to the full requirements class that we approved in Phase 1 of the Companies' Rate Cases, with the addition of the revised DG Meter Fee discussed below.

The Companies' proposal to limit the options for new partial requirements DG customers to either a two-part or three-part TOU rate is reasonable. No party disputes that TOU rates are an effective and equitable way to incentivize customers to reduce peak demand during the system peak. In Phase 1 of the TEP Rate Case, we directed that the default for new residential customers after January 1, 2018, would be the TOU rate.[428] We found in Phase 1 of the UNSE Rate Case that it was time for a

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[427] We make no determination regarding the reasonableness of a GAC in a future proposed rate design. A GAC based on capacity of the DG system is one way to ensure that DG customers who do not opt for the rate design with demand charges still pay approximately the same proportion of the fixed costs of the grid needed to serve them. APS has utilized GACs for many years. Well-designed two-part TOU rates, without a GAC, or with a modest GAC, represent another way to collect fixed costs from the partial requirements customers.

[428] Decision No. 75979 at 193.

more modern rate design and that well-designed TOU rates would allow for better recovery of costs and send correct price signals to customers to shift loads away from system peak periods.[429] Thus, we find it is reasonable to continue to encourage the transition to TOU rates.

No party opposes the three-part TOU rate option for new DG customers, except that Vote Solar believes that the threshold for the second-tier demand charge should mirror the non-DG three-part TOU rate option that starts at demand greater than 7 kW (instead of the 5 kW proposed here for DG). TEP has not convinced us that the threshold for increased demand charges under the three-part rate should be lowered to 5 kW from 7 kW for non-DG customers. We agree that there are benefits to maintaining an easily comparable rate structure as the calculations for going solar should be easier to perform, and the Companies can adjust the kWh-variable portion of the rates to yield the required revenue.

We adopt Vote Solar's DG Meter Fee of $2.33 per month for new DG residential customers, and $0.90 per month for new SGS DG customers. The DG Meter fee is intended to recover only the incremental costs associated with the bidirectional meter that is required to serve the DG customers. The Companies compared the cost of a new bidirectional meter with the embedded cost of a standard meter. This analysis likely overstates the incremental costs because embedded costs are net of accumulated depreciation, which is comparing a new bidirectional meter with a used standard meter. It is more equitable to compare the costs of new meters.

Vote Solar's DG meter proposal is more conservative and better comports with the principles of gradualism. However, we find that it is not in the public interest to re-authorize a one-time upfront payment in lieu of the monthly DG meter fee. We approved a one-time payment option in Phase 1 of the TEP Rate Case, although we were clear that we would re-evaluate the proposal in Phase 2. We did not approve a one-time upfront option in Phase 1 of the UNSE Rate Case. Based on the additional evidence presented in these Phase 2 proceedings, we agree that the one-time payment option violates fundamental ratemaking principles and creates several operating concerns. Future operating and capital costs associated with the meters are not known and measurable. The appropriate amount to collect in a one-time payment is the present value of the perpetually incurring operating and capital

[429] Decision No. 75697(August 19, 2016) at 65-66.

costs, and if the amount of these costs were known and a discount rate selected, it would be possible to calculate the present value, however the amounts are not known. We do not have any degree of comfort that the proposed payment is sufficient to account for on-going costs of repairs, upgrades or meter replacement. In addition, if the one-time payment was to be treated as revenue, there would be a mismatch among revenues, expenses and rate base. When the Companies incur meter related on-going operating costs in the future, those costs would need to be removed from the costs to be recovered in future rates. The Companies would need to maintain a perpetual record of the customers that are not to be charged for the meters which creates an unnecessary burden and potential confusion. There is no one-time option for the BSC, and the same concept that argues against such option for standard meters applies to the bidirectional meter. Thus, we discontinue the one-time up-front payment option approved for new DG customers in Phase 1 of TEP's Rate Case.

G. Resource Comparison Proxy[430]

1. RCP Rate

The RCP recommendations of the parties are summarized as follows:

	TEP cents/kWh	UNSE cents/kWh	Combined cents/kWh	Years	Additional Adders Cents/kWh	1st Reset Date
TEP/UNSE			9.73/10.7[431]	2012-16		7/1/18
AIC			9.73	2011-15		1 year
RUCO			9.7	2012-16		1 year
TASC/EFCA			12.5	2011-15	2.0	1 year
Vote Solar			12.4	2012-16[432]	3.0	1 year
Koch	10.78					1 year
Plenk						1 year

430 We note that in other proceedings parties have asserted that the Value of Solar Decision only applies to Residential customers and that the SGS Class should not be subject to the RCP and remain on net metering. No party raised that issue in these proceedings. Furthermore, the TEP and UNSE Phase 1 orders directed that the Phase 2 proceeding would apply to both Residential and SGS customers.

431 TEP recommends a combined RCP of 9.73 cents/kWh if the reset date is not July 1, 2018.

432 Vote Solar only recommends the 2012-2016 rolling average if its recommendations for the T&D and Line loss adders are adopted.

Staff	10.5	12.8	10.7	2012-16		7/1/18

Because 2017 data for utility-scale facilities and PPAs are known the parties have recommended the following RCP rates for Year 2 of the RCP:

	TEP cents/kWh	UNSE cents/ kWh	Combined Cents/ kWh	Effective Date
TEP/UNSE	9.3	9.4	8.76	7/1/18
AIC			8.76	1 year after effective date
RUCO			8.73	1 year after effective date
TASC/EFCA			11.25	1 year after effective date
Vote Solar			11.2	1 year after effective date
Koch	9.7[433]			1 year after effective date
Plenk[434]				1 year after effective date
Staff[435]	9.5	11.5	9.63	7/1/18

Vote Solar argues that the Commission cannot eliminate net metering and adopt the RCP methodology without repealing the Net Metering Rules. However, the Commission determined in the Value of Solar Decision that continuing net metering for new residential DG systems was no longer in the public interest. After extensive testimony, analysis, a hearing, and debate at Open Meeting, the Commission adopted the RCP and avoided cost methodologies for valuing the exported energy from the DG systems. Specifically, for the pending TEP and UNSE Phase 2 rate proceedings the Commission directed that the RCP method would be utilized. The Value of Solar Decision was not appealed and is a final Order of the Commission. The Commission adopted the RCS methodology in the recent APS rate case. Thus, we find that the arguments against utilizing the RCP methodology in these cases is an impermissible re-litigation of, or collateral attack on, the Value of Solar Decision and cannot stand.

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433 Assuming 10 percent reduction from initial proposed rate.
434 Mr. Plenk did not advocate for a specific rate in his Briefs.
435 Ex Staff-P2-4 (Smith Surr) at 13. Staff's proposed rates are 10 percent less than its initial proposed rate.

The Value of Solar Decision provides:

> For the Resource Comparison Proxy Methodology with a Five-Year Rolling Average (Based on Projects and PPAs with In-Service Dates within the Last Five Years). Staff shall use the spreadsheet described in this Decision to develop a proxy for rooftop solar generation, based on a utility's projects and PPAs with in-service dates within the five years up to and including the test year of the rate case. If projects of recent vintage are not available for the utility, Staff shall use pricing data from available industry sources for grid-scale solar PV projects, with priority given to projects in Arizona to the extent available. DG should receive credit for costs that it avoids that central station solar (and other central station generation) do not avoid. As a result, the Resource Comparison Proxy we adopt herein will require that avoided transmission, distribution capacity and line losses be considered in the analysis.[436]

After considering the totality of the evidence and all the circumstances of these proceedings, we find that Staff's recommended methodology for calculating separate RCP rates for TEP and UNSE best captures the intent, goal, and spirit of the Value of Solar Decision. We agree with Staff that separate RCP rates are appropriate for TEP and UNSE. The Companies have their own solar facilities and PPAs; they have different service territories in disparate parts of the state; they have distinct and different depreciation rates and costs of capital; and different costs of service and rates. We also agree with Staff that unless there is no year within the five-year time frame with data for solar facilities put into service and PPAs, that the weighted average should be based on actual data for the utility rather than industry data. This method lessens the costs and complexities of accumulating, analyzing, and litigating which industry data best serves as surrogate for the RCP. Further, we do not find sufficient evidence of avoided transmission and distribution avoided costs associated with DG at this time to support adopting any additional adders. However, we do not acquiesce here that future costs can never be regarded as avoided costs where the evidence is clear that a future investment can be avoided due to DG.

Staff included the 12-month period after the test year to determine its five-year period for calculating the average. There was much debate during the hearing based on language in various places in the Value of Solar Decision about which five years best represent the intent the Commission. When the Value of Solar Decision was debated, the Commission clearly believed that these Phase 2 proceedings would be resolved quicker than they have been. In referencing the test year, the

[436] Decision No. 75859 at 153.

Commission defaulted to a standard reference point often used in ratemaking. We do not believe that the Commission intended the test year to be a hard and fast limit for calculating the five-year average. The Commission often makes pro forma adjustments to the test year to factor in known and measurable changes to the test year.

We acknowledge that the hearings in these Phase 2 proceedings were further removed from the date of the Value of Solar Decision than contemplated by the Commission when it issued the Value of Solar Decision. Delays were caused by the pending APS rate case which involved many of the same parties who participated in these proceedings, and strain on the Commission's resources during the period after the parties requested suspension of the procedural schedule to allow for settlement discussions and rescheduling. The delay was regrettable but unavoidable. In the intervening period after the issuance of the Value of Solar Decision to the present, more DG customers connected under the old net metering scheme, resulting in the cost shift associated with net metering to continue longer than anticipated with non-DG customers continuing to pay for the DG cost shift. The intervening months also gave the solar industry more time to adjust to the new rate dynamics.

We do not believe that having an RCP in place for a short period of such as 2 months, or even 6 months, and subsequently reducing it by up to 10 percent, is reasonable. Rather, we find that it will be less disruptive and confusing to set an RCP that will be in effect for a longer period before it is reset.

We find that the initial RCP should not rely on outdated data. The data for 2017 is now available, and is current, therefore, it is reasonable to use the 2017 data to inform the initial RCP rates for TEP and UNSE, and for these rates to be in effect from the effective date of this Decision until they are reset—the later of one year thereafter, or May 1, 2019. Therefore, based on the totality of the evidence, we adopt initial RCP rates of 9.64 cents per kWh for TEP and 11.5 cents per kWh for UNSE.

We do not find it necessary to adopt Vote Solar's proposal for Year 11 and beyond at this time. We did not address the issue in the recent APS rate case. We anticipate that actual experience operating under the RCP rate will assist us in making a more informed decision whether any action needs to be taken with respect to Year 11.

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2. RCP Plan of Administration

Staff presented an RCP POA with the Direct Testimony of Ralph Smith.[437] TEP and UNSE were the only parties who offered modifications to Staff's proposed POA.[438] The Companies' modifications reflect their position that the RCP rate should be a combined rate for TEP and UNSE, and their calculation of the five-year rolling average to include 2016 data.

TEP and UNSE should submit RCP POAs as compliance items in their respective dockets that comport with our findings herein. The POA Procedural Timeline shall be adjusted to reflect the approved reset date and the "Base Year" adjusted such that the 2019 reset will be calculated based on the calendar year ending December 31, 2018, subject to the 10 percent limit on the annual reduction.

3. AECC's Cost Recovery Proposal

AECC, representing the interests of large and industrial customers, does not want these customers to pay more for the above-market cost of exported DG power. AECC proposed that the cost of the RCP rate that is above the MCCCG not be recovered in the PPFAC, which affects all customers, but rather that the above-market costs be collected from the Residential and SGS classes in the REST surcharge. AECC also argued that the current caps on the REST surcharge for customers not eligible for the RCS tariff should not be raised on account of the RCP.

TEP and UNSE do not oppose recovering the costs of purchasing DG exported energy purchased through the PPFAC up to an amount equal to the Companies' MCCCG and recovering the above-market costs through the REST surcharge. The Companies oppose, however, limiting the ability to increase the REST caps based on DG purchases.

Staff did not address AECC's cost recovery proposal in its briefs. At the hearing, Mr. Smith testified that Staff did not oppose AECC's proposal to recover the above-market costs of the RCP rate through a mechanism other than the PPFAC.[439] Mr. Smith believed that portion of the AECC proposal is consistent with how utility-scale solar costs are currently recovered. However, Mr. Smith testified that Staff opposed that portion of AECC's proposal that none of the costs of the RCP should be

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[437] Ex S-P2-1, Attachment RCS-8.

[438] In its Reply Brief, AECC offered additional language to the POA regarding it proposal concerning cost recovery of DG exports pursuant to the RCP rate.

[439] Tr. at 1161.

recovered by customers who are not eligible for the program.[440]

We agree that the cost of the purchased DG power up to the MCCCG is appropriately recovered through the PPFAC. Further, the above-MCCCG cost of the rate should be recovered through a separate surcharge mechanism. The REST surcharge is intended to recover the costs of Commission-authorized renewable energy resources, and is an appropriate mechanism for this purpose. We do not believe, however, that the Residential and SGS classes are the only customers who benefit from the RCP tariff. The reason we have rates to incentivize investment in renewable resources is for the benefit of all the utilities' customers, through the environmental benefits and a reduced need to construct new generation. Thus, we do not adopt the proposal to exclude a particular customer class from participating in the recovery of the above-market costs attributable to the RCP. We can review the appropriateness of any caps on the REST surcharge in a generic docket addressing the REST or in individual REST Implementation Plan dockets. We do not find it necessary to address the cost recovery of the RCP in the POA.

H. RUCO's TOG Proposal

No party opposed the concept of RUCO's TOG Proposal that is aimed at incentivizing DG customers to orient their systems to the west to generate more production during TEP's system peak in the afternoon. The details of RUCO's TOG Program have not been worked out. Staff recommends that details for a pilot program be developed based on RUCO's proposal and that the program be rolled out as a pilot with limited participation so that the results can be analyzed.[441]

We find that Staff's recommendation is reasonable. By studying the proposal as a pilot, we can determine if there are any unintended consequences, as well as determine if there are ways to design the tariff to be most effective. West facing systems produce less energy than south facing systems, but produce it in the later afternoon when it has the most value for an afternoon peaking system. While RUCO's proposal may help lower peak demand, if not designed well, it is possible it could have the effect of decreasing overall solar production in the early afternoon which could lead to greater use of base load plants (more typically coal-fired) to meet system load demand. This in turn, could have

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[440] Tr. at 1161-62.
[441] Tr. at 1291.

negative environmental consequences. We do not conclude here that the RUCO proposal will result in negative consequences, only that the concept should be studied, and that a pilot program would be the best step forward. We will direct TEP and UNSE to file a proposed pilot program based on RUCO's TOG Program within 120 days of the effective date of this Decision.

I. Residential Community Solar and Bright Tucson

1. RCS Program

TEP proposes a RCS program under which Standard Residential customers who own their homes, would be able to enter into a 10-year contract for the purchase of solar energy from a new TEP- or third-party owned 5 MW solar plant to be interconnected with TEP's distribution grid. The homeowner would contract for the solar energy to be produced from the new 5 MW plant based on that individual home's historic consumption and the plant's average solar production per kW, to create a Solar Rate Capacity. The homeowner would pay a fixed monthly solar payment based on the Solar Rate Capacity and the proposed tariff of $19.00 per kW. Customer billing would be evaluated annually and raised or lowered if a participant customer's consumption increased or decreased by 15 percent. There would be "regulatory out" and termination clauses. Proponents of the program (TEP, RUCO, Staff) believe it will bring additional solar resources to TEP's customers cost-efficiently.

Opposition to the RCS is based on TEP not offering the program to renters; an alleged cost shift attributable to the program; and because advocates for third-party rooftop solar manufacturers and installers cannot offer solar energy on the same terms.

We do not find that any of the reasons given for opposing the RCS program warrant our denial of the program. The RCS is the most cost-effective residential solar program that has been proposed to date. Mr. Jones testified in the 2016 REST Implementation Plan proceeding that the RCS program, which uses utility-scale solar, costs 40 percent less than rooftop DG, including TEP's TORS program.[442] Subsidies are not the same as cost shifts. The proposed Solar Rate Capacity is calculated to recover an equivalent amount of revenue from a participating customer as from a non-participating customer (i.e., the fixed monthly solar payment would be the same as a non-solar customer of similar

[442] *See* Ex TEP-3 (Jones Dir. filed in Docket No. E-01933A-15-0219) at 20.

load). To the extent that there might be a subsidy, it is likely small, consistent with that for similarly situated non-DG customers, and certainly less than the subsidies paid to rooftop solar under net metering or the RCP. We find that the fact that renters are not eligible for the RCS is not a reason to deny approval. The RCS Program is a cost-effective way to bring more solar resources into TEP's service territory, a benefit to all; and the fact that renters are not eligible does not negate the benefits of the program.

Further, the 15 percent usage variance under the terms of the program is not reason to reject the RCP program. On average, the RCP program will provide customers with billings that reflect their current usage. If a customer's usage varies so wildly as to fall outside of the 15 percent variance, the contact prices will be recalculated.

Neither is the fact that rooftop solar installers cannot offer PV systems on the same terms as the RCS reason to prevent TEP from offering a cost-effective program. The RCS will be attractive to those customers who do not want to have a PV system on their roof, or cannot install one for structural or financial reasons. It is likely that some residential customers who would otherwise be capable and interested in installing a rooftop system, but prefer the structure of the RCS program, will opt to participate in the RCS program over installing their own rooftop system. However, because the RCP is limited to 5 MW, it is not likely to cause the collapse of the rooftop solar industry in TEP's territory. Consequently, we approve the RCS program as proposed.

TEP has requested that we waive the requirements of the REST Rules that DG be located on the customer's premises in order that the RCS program can qualify for the residential DG carve-out under the REST Rules. Staff agrees that the waiver is appropriate under the circumstances.

At the time of the hearing, TEP believed that by the end of 2017, it would exceed its obligations under the REST DG target by over two times, and stated that if no additional residential DG installations occurred, TEP would already meet its 2023 residential target and be at 89 percent of the 2025 target.[443] Solar installations in TEP's service territory have exceeded the REST Rule targets. The declines in the cost of utility-scale solar have made it possible to bring less expensive solar energy to

[443] TEP Opening Brief at 6; Ex TEP/UNSE-P2-4 (Dukes Reb) at 6.

residential customers in ways not contemplated at the time the REST Rules were adopted. For the limited purpose of this RCS project, we agree with the Company and Staff that the project can qualify as residential DG. We urge TEP and other interested parties to propose additional types of community solar projects for our consideration in TEP's next REST Implementation Plan.

TEP has testified that if a customer wishes to terminate the RCS contract early, there will be a termination charge based on the remaining term of the contract. Testimony did not explain how the termination charge would be determined. We direct TEP to clarify in its RCP tariff the basis calculating the termination charge.

2. Bright Tucson

Bright Tucson is an existing program that provide an option for any residential or SGS customer to purchase 150 kWh blocks of solar energy at a 2-cent premium over standard retail rates. TEP proposes to lower the premium to 1 cent per kWh. No party opposed TEP's proposal except Mr. Plenk who believed that the premium should be zero (although he is willing to agree to a ½ cent premium.

We agree with TEP's reasoning that a 1 cent premium for this voluntary program is appropriate at this time.

J. Residential Battery Storage Rate

TEP and UNSE believe that additional storage-specific rates are not necessary because the current three-part rates are sufficient to send the appropriate price signals to customers that they might benefit from behind-the-meter technologies that reduce their demand. The Companies appear to understand, however, that the Commission has recently been investigating rates to incentivize battery storage. The Companies state that any directive in this case to submit a residential storage-specific rate be considered as a pilot and that they be permitted to also submit options that include a ratchet provision. The Companies also claim that their billing systems are not capable of implementing daily demand charges as advocated by TASC/EFCA.

Staff does not address the Residential Battery Storage proposal in its Briefs. In his testimony at hearing, Mr. Smith discussed Staff's recommendation that the parties develop something like the

"R-Tech rate" that the parties agreed to in the APS rate case.[444] Mr. Smith testified that the parties in the APS rate case agreed to a pilot rate, called the R-Tech, that was intended to encourage the use of distributed generation technology coupled with another form of technology, which would include storage. Mr. Smith believed that the tariff was limited to the number of customers who could participate initially. Staff believed that the process of designing a tariff to encourage "behind the meter" technology should be a collaborative process. [445] In this case, Staff recommended any R-Tech-like tariff be limited to 4,000 customers for TEP and 1,000 customers for UNSE.[446]

We find that recommendations for a tariff designed to encourage residential customers to install behind-the-meter technology that would assist them to reduce their demand are reasonable. While we believe such pilot could include storage as an option, we do not think that it should be limited to any one type of technology, thus, we will not add additional constraints and do not automatically foreclose a demand ratchet as an option, although we believe that for ratchets to be reasonable, they should include a seasonality component. Consequently, we direct the Companies to file a proposed R-Tech-like tariff for Staff and the parties to review within 120 days of the effective date of this Decision. TEP and UNSE may propose a ratchet option if the Companies also submit a non-ratchetted option.

K. Data Availability

Mr. Woofenden testified that currently TEP does not provide hourly load data in a form that can be easily downloaded by the customers and used for modelling purposes.[447] Mr. Plenk advocated for more timely release and efficient release of the "8760 files" to customers who request them.

It is our understanding that the data contained in these files is important to customers making the decision to "go solar" and that in the past, receiving the data in the files has been cumbersome. No party disputes the need for the files nor the customers' right to receive the data.

Consequently, we direct TEP to formulate a web-based process for receiving customers' requests, and that would allow for easy, electronic access to their hourly load data. TEP shall file within 60 days of the effective date of this Decision verification that it is making this data available through

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[444] Tr. at 1305.
[445] Tr. at 1306-06.
[446] Tr. at 1308-09.
[447] Tr. at 645.

its website, or an explanation why the process is not available and an estimation of when it will be operational.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. TEP provides service to almost 415,000 customers in Pima County, Arizona, of which approximately 90 percent are residential, 9 percent are commercial, and less than 1 percent are industrial/mining. TEP also provides power to Fort Huachuca, a U.S. Army base located in Cochise County.

2. TEP is a subsidiary of UNS Energy, which is also the parent of UNSE. UNSE provides electric service to approximately 95,000 customers in Santa Cruz and Mohave Counties.

3. TEP filed an application for a rate increase on November 5, 2015, based on a test year ended June 30, 2015.

4. The Commission approved a rate increase for TEP in Phase 1 of its Rate Case in Decision No. 75975 (February 24, 2017). The Commission deferred consideration of the issues in the Rate Case related to DG rate design and modifications to net metering to Phase 2 of the Rate Case which would take place after the Commission concluded its investigation and findings in the Value of Solar docket.

5. The Commission issued Decision No. 75869 in the Value of Solar docket on January 3, 2017.

6. The procedural history of Phase 2 of TEP's Rate Case and the summaries of the parties' positions as set forth in the Discussion Section of this Decision are accurate and adopted as though set forth fully here.[448]

7. TEP and UNSE have access to, and transact within, the same market; are operated as a single balancing authority, with TEP providing control area services for UNSE, have interconnected

[448] For a complete description of the procedural history of Phase 1 of the Rate Case, see Decision No. 75975.

points of operations and can take advantage of shared facilities, and utilize shared resources, such as personnel in the renewables department, wholesale marketing, control area, accounting and management.

8. Given the overlap in the parties, the subject matter of the Phase 2 proceedings, and witnesses, it was reasonable to conduct the TEP and UNSE Phase 2 Rate Case proceedings concurrently.

9. Cost causation is the primary consideration for allocating costs. The cost driver for the distribution system is capacity. The capacity of a distribution circuit does not depend on whether it is used for delivery of energy to the customer or the export of energy from the customer. Distribution circuits must be built to accommodate the combined maximum demand capacity for delivery and export usage.

10. Both load demand and export energy production have the potential to be the constraining factor on the demand capacity of a distribution circuit. Accordingly, depending on the circumstances, either may be the appropriate factor for allocating distribution costs between the DG and non-DG customer classes.

11. In this case, TEP's use of the separate class NCP demands instead of the relative demands each class places on the distribution system at the time of their combined maximum demand, does not attribute the cost of the distribution system in proportion to cost causation between the DG and non-DG classes, and is, therefore, inequitable.

12. Under current conditions usage of the grid during times other than the net combined NCP of the DG and non-DG classes should not be factored into the allocation of the distribution costs as it does not drive distribution capacity costs.

13. TEP must revise its CCOSS for the Commission to evaluate its proposed DG rates. Absent a revised CCOSS that equitably allocates costs, we cannot determine if the rates of return of the various classes are equitable under the proposed rates.

14. It is reasonable that until TEP submits a revised CCOSS and new DG rate options for approval by the Commission, new Residential and SGS DG customers who submit an application to interconnection after the effective date of this Decision shall take service under any of the TOU rate

options available to the full requirements class that we approved in Phase 1 of TEP's Rate Case, with the addition of the revised DG Meter Fee approved herein.

15. There are benefits to maintaining an easily comparable rate structure between the non-DG class and the DG class as the calculations for going solar should be easier to perform, and the Companies can adjust the kWh-variable portion of the rates to yield the required revenue. Thus, at this time, it is reasonable to maintain the same thresholds for demand tier charges between the classes.

16. It is reasonable to adopt a DG Meter Fee of $2.33 per month for new DG residential customers, and $0.90 per month for new SGS DG customers.

17. As discussed herein, it is not in the public interest to continue a one-time upfront payment in lieu of the monthly DG meter fee.

18. Separate RCP rates are appropriate for TEP and UNSE as the Companies have their own solar facilities and PPAs, different service territories in distinct parts of the state, distinct and different depreciation rates and costs of capital, and different costs of service and rates.

19. It is reasonable in calculating the RCP rate that, unless there is no year within the five-year time frame with data for solar facilities put into service and PPAs, the weighted average should be based on actual data for the utility, rather than industry data.

20. In this proceeding there is not sufficient evidence of avoided transmission and distribution costs associated with DG to support adopting any additional adders. However, our finding in this case does not mean that future costs can never be regarded as avoided costs where the evidence is clear that a future investment can be avoided due to DG.

21. The initial RCP should not rely on outdated data, and it is not reasonable to reset the RCP sooner than one year from its approval.

22. It is reasonable to approve an initial RCP rate of 9.64 cents per kWh for TEP.

23. It is reasonable that the initial RCP rate shall be in effect from the effective date of this Decision until the later of one year thereafter, or May 1, 2019.

24. It is reasonable that the RCP rate will be reset based on the five-year rolling average from 2014-2018, moderated by the 10 percent annual reduction cap we approved in the Value of Solar Decision.

25. It is reasonable to require TEP to file a revised POA for the RCP that conforms to the findings herein, as a compliance item in this docket, within 30 days the effective date of this Decision.

26. It is reasonable that the cost of the purchased DG power up to the MCCCG is appropriately recovered through the PPFAC, and that the above-MCCCG cost of the rate should be recovered through the REST surcharge, or such other surcharge mechanism as may be approved in the future.

27. It is not in the public interest to adopt any limits on the recovery of the above-market costs attributable to the RCP in this docket.

28. It is reasonable to direct TEP to submit a tariff designed to encourage residential customers to install behind the meter technology that would assist them to reduce their demand are reasonable. It is reasonable to direct TEP to file with Docket Control, as a compliance item in this docket, a proposed R-Tech-like tariff for Staff and the parties to review, within 120 days of the effective date of this Decision.

29. It is reasonable to address RUCO's proposed TOG Proposal as a pilot program and to direct TEP to file with Docket Control, as a compliance item in this docket, a proposed pilot program based on RUCO's TOG Program within 120 days of the effective date of this Decision.

30. As discussed herein, the RCS Program as proposed by TEP is in the public interest and should be considered as residential distributed generation.

31. Community solar programs represent a cost-effective way to bring additional solar resources to TEP's service territory. TEP and other interested parties should determine if there are additional types of community solar projects that should be considered for approval and make proposals for our consideration in TEP's next REST Implementation Plan.

32. It is reasonable to direct TEP to clarify how the termination charge for the RCS Program will be determined in the RCS tariff.

33. It is reasonable to approve the modifications to the Bright Tucson program as proposed by TEP.

34. It is reasonable to direct TEP to formulate a web-based process for receiving customers' requests and allowing easy, electronic access to their hourly load data.

CONCLUSIONS OF LAW

1. TEP is an Arizona public service corporation within the meaning of Article XV, Section 2 of the Arizona Constitution, and A.R.S. §§ 40-203, -221, -250 and -361.

2. The Commission has jurisdiction over TEP and over the subject matter of this proceeding.

3. Notice of Phase 2 of TEP's Rate Case was provided as required by law.

4. The rates and charges authorized herein are just and reasonable, and should be approved.

ORDER

IT IS THEREFORE ORDERED that Tucson Electric Power Company shall file no later than April 30, 2018, a schedule of rates and charges that conform to the findings herein for new Residential and SGS DG customers who interconnect after the date of this Decision.

IT IS FURTHER ORDERED that consistent with Decision No. 75859, a new Residential or SGS DG system that submits an application to interconnect to Tucson Electric Power Company's distribution system after the effective date of this Decision shall be placed on the DG export rate effective at the time of the application to interconnect for a period of ten years.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall file with Docket Control, as a compliance item in this docket, a revised POA for the RCP that conforms to the findings herein, within 30 days the effective date of this Decision.

IT IS FURHTER ORDERED that the Residential Community Solar Program as proposed by Tucson Electric Power is approved and shall be considered as residential distributed generation. Tucson Electric Power Company shall file with Docket Control, as a compliance item in this docket, an RCS Tariff that complies with our findings herein, within 30 days of the effective date of this Decision.

IT IS FRUTHER ORDERED that Tucson Electric Power Company's proposed revisions to its Bright Tucson program are approved, and Tucson Electric Power Company shall file with Docket Control, as a compliance item in this docket, a revised Bright Tucson Tariff that complies with our findings herein, within 30 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall file with Docket Control, as a compliance item in this docket, a tariff designed to encourage residential customers to install behind the meter technology that would assist them to reduce their demand similar to the R-Tech-like tariff, within 120 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall to file with Docket Control, as a compliance item in this docket, a proposed pilot program based on RUCO's TOG Program, within 120 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Tucson Electric Power Company shall within 60 days of the effective date of this Decision, as a compliance filing in this docket, file verification that it is making the hourly load data of its customers available in an easily downloadable file from its website, or an explanation why the process is not available and an estimation of when it will be operational.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN FORESE — COMMISSIONER DUNN

COMMISSIONER TOBIN — COMMISSIONER OLSON — COMMISSIONER BURNS

IN WITNESS WHEREOF, I, TED VOGT, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this ______________ day of __________________ 2018.

TED VOGT
EXECUTIVE DIRECTOR

DISSENT ________________________

DISSENT ________________________

SERVICE LIST FOR: TUCSON ELECTRIC POWER COMPANY

DOCKET NO.: E-01933A-15-0239 AND E-01933A-15-0322

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EXHIBIT A

Attachment RCS-8

Draft Resource Comparison Proxy Plan of Administration for TEP

TEP

PLAN OF ADMINISTRATION
RESOURCE COMPARISON PROXY

Resource Comparison Proxy
Plan of Administration

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1. General Description

This document describes the plan for administering the Resource Comparison Proxy purchase rate ("RCP") approved for Tucson Electric Power Company ("TEP" or "Company") in Arizona Corporation Commission ("Commission") Decision No. 75859 (January 3, 2017), as modified by Decision No. 75932 (January 13, 2017) and implemented in Decision No. xxxxx (xxx x, 2017). The RCP is the price at which the Company purchases Exported Energy from residential Customers with qualified on-site solar distributed generation facilities. This price is provided in Rate Rider RCP.

The RCP is a proxy for the avoided cost of providing electrical service that results when a distributed generator exports power to the grid. The RCP is calculated using: (i) a rolling historical five-year weighted average cost of grid-scale solar photovoltaic facilities that the Company owns or has rights to through a solar photovoltaic Purchased Power Agreement (PPA); and (ii) applicable Avoided Transmission Capacity Cost, Avoided Distribution Capacity Cost, and Line Losses.

2. Definitions

Avoided Cost. In the context of this Plan of Administration, the additional cost TEP would incur to acquire electric energy to serve its customers if electricity was not available from on-site distributed generation sources.

Avoided Distribution Capacity Cost. In the context of this Plan of Administration, the net cost of distribution grid equipment and facilities necessary to distribute electricity to TEP customers if electricity from on-site distributed generation sources was not available.

Avoided Transmission Capacity Cost. In the context of this Plan of Administration, the additional cost of transmission grid equipment and facilities necessary to transmit electricity to TEP customers if electricity from on-site distributed generation sources was not available.

Base Year. For the initial RCP calculation (effective July 1, 2017), the base year is 2015. Each subsequent annual calculation will use the immediately preceding calendar year as the Base Year. As an example, the RCP that will become effective with the first billing cycle of July 2018 will be calculated with the calendar year ending December 31, 2017 as the Base Year.

Customer(s). For purposes of this Plan of Administration, a TEP Customer taking service under a Residential rate schedule.

Export(ed) Energy. Energy generated by an on-site interconnected solar photovoltaic distributed generation source that is greater than the Customer's electric load at any single point in time and flows into the Company's distribution grid.

Levelized Cost. For purposes of this Plan of Administration, the net present value of the overall cost of building and operating a grid-scale solar photovoltaic generating plant, or the net present value of the overall cost to TEP of an executed solar photovoltaic PPA, over the economic life of the asset and converted to equal annual amounts.

Line Losses. Electric energy lost as it is transmitted from a supply source (i.e., an electric generation plant) to a delivery point (i.e., the Customer's residence or place of business).

Partial Requirements Service. Electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies The Customer's own electric requirements, and any excess generation (over and above the Customer's own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

Production Tax Credit. The income tax credit available in the State of Arizona for taxpayers that own a qualified renewable energy generator as defined in Arizona Revised Statutes ("A.R.S.") §43-1083.02 and §43-1164.03 that produces energy after December 31, 2010 and before January 1, 2021. The amount of Production Tax Credit available is limited by facility and by calendar year.

Revenue Requirement. For purposes of this Plan of Administration, the amount of revenue calculated to be recovered in rates for the TEP-owned grid-scale solar facilities included in the RCP calculation. Revenue Requirement expenses include depreciation expense, income taxes, property taxes, deferred taxes and tax credits where appropriate, associated operation and maintenance expense, and an approved debt and equity return.

3. Resource Comparison Proxy Purchase Rate

The RCP will be determined as follows:

- An RCP will be determined for each tranche of new DG Customers, effective July 1 each year without proration. The RCP may not be reduced by more than 10% from the previous year.

- Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before July 1, provided that they subsequently complete the installation and obtain approval by the appropriate Authority having jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or TEP. In that circumstance, the Customer will have 270 days to complete their interconnection.

- Each Customer's initial RCP will be applicable for 10 years from the time of their interconnection.

- After each Customer's initial 10-year period the bill credit will be based on the purchase rate in effect at that time, and will change from year to year.

4. Customer Billing

The Company will provide the Customer a monthly bill credit for the Export Energy based on the applicable RCP.

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; if the outstanding credits exceed $25 a check will automatically be issued; otherwise the bill credits will carry forward to the following year.

5. System Eligibility

A Customer's distributed generation facility must meet all of the following qualifications in order to be eligible to receive the RCP:

- Electricity must be generated using solar photovoltaic panels;

- The facility must be interconnected to the Company's distribution grid;

- The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;

- The facility's nameplate capacity cannot be larger than the following electrical service limits:
  a. For 200 Amp service, a maximum of 15 kW-dc,
  b. For 400 Amp service, a maximum of 30 kW-dc,

c. For 600 Amp service, a maximum of 45 kW-dc,
d. For 800 Amp service and above, a maximum of 60 kW-dc; and

- For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in alternating current ("AC") over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).

SPECIAL CASES

Switching from a grandfathered legacy solar rate. A Customer may choose to switch from a grandfathered solar legacy rate and net metering rider to a new retail rate and the RCP rider. However, the Customer will lose their grandfathering status for any remaining years on the grandfathered net metering rider. A Customer who switches may not subsequently switch back to the grandfathered rate or net metering program. In addition, a Customer who moves to the RCP rider will not be eligible for an initial 10-year lock in the purchase rate; rather their bill credits will be based on the annual RCP rate which changes from year to year.

Increasing Capacity. If a Customer modifies the generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this Plan of Administration, a material increase in capacity means increasing the capacity by 10% or 1 kW, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase the system's capacity by a total of 10% or 1 kW, whichever is greater.

Transferring Service. If a Customer moves to a site that is currently being served under the RCP rate rider, they will continue service under the rider with the same rate tranche for the remainder of the 10-year term. If a Customer moves the solar system to another site the Customer will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate which changes from year to year.

6. Calculation of Resource Comparison Proxy Purchase Rate

The RCP is calculated by developing a historical rolling five-year weighted average cost per kWh for all grid-scale renewable solar photovoltaic generating systems used by TEP to serve its customers, TEP-owned facilities and facilities from which TEP purchases power through an executed PPA. The calculation methodology is as follows:

The first RCP effective on July 1, 2017 is $____/kWh, using 2015 as the Base Year. Subsequent RCPs derived from following the calculations in Steps 1 through 8 below will then be compared to the RCP in effect. If the calculated RCP results in a reduction in the purchase rate from the previous RCP, any such reduction will be no greater than 10% of the previous RCP.

TEP

PLAN OF ADMINISTRATION
RESOURCE COMPARISON PROXY

1. Determine appropriate five-year period. The RCP will be calculated using the 5-year period with the Base Year as the final year of the five years. Only those grid-scale solar photovoltaic projects with an in-service date within this 5-year period will be included in the annual RCP calculation.

If there are no grid-scale solar photovoltaic projects with an in-service date within the rolling 5-year period described above, the rolling 5 year average will continue to be calculated using the 5-year period despite no projects being in-service for any particular year.

2. Develop/update annual Revenue Requirement for each TEP-owned facility. The Company will calculate revenue requirements for each grid-scale solar photovoltaic generation facility owned by the Company that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual designed output of the facility, including degradation, will be used for this calculation. This step provides an annual revenue requirement cost in dollars for each year of the facility's depreciable life.

3. Incorporate applicable Production Tax Credit. All expected available annual Production Tax Credit tax savings (in dollars) for the above TEP facilities will be calculated based on expected annual energy production and subtracted from the annual facility cost derived in Step 2 above for each year.

4. Develop/update annual cost of power for each PPA facility. The Company will calculate an annual cost of purchased power for each facility from which TEP purchases power under an executed agreement that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual cost for each of these facilities will be calculated separately for the contract life of each PPA using the contract price and the designed output, including degradation, of the facilities, including contractual escalation factors, as appropriate.

5. Calculate individual facility Levelized Cost. The Levelized Cost for each of the facilities will then be calculated using the data derived in Steps 2 through 4 above. The net present value discount rate used in the Levelized Cost calculations will be calculated using the approved after-tax weighted average cost of capital as determined in the Company's most recent rate case. The result of this calculation step will be a Levelized Cost per MWh for each of the facilities.

6. Calculate weighted Levelized Cost for each facility. The weighted Levelized Cost is calculated by multiplying the cost per MWh derived for each facility in Step 5 by the actual Base Year energy production in MWh for each Step 5 facility. The result of this step is an annual weighted cost in dollars for each included facility.

7. Calculate weighted average Levelized Cost for all facilities. The annual weighted average Levelized Cost is determined by dividing the total annual weighted costs for all included facilities by the total Base Year energy production MWh. The result of this step is the rolling historical five-year weighted average cost per MWh for grid-scale solar photovoltaic facilities on the TEP system before any applicable adjustments.

8. Adjustments. An adjustment is then applied to the annual weighted average Levelized Cost per MWh for avoided transmission capacity cost, avoided distribution capacity cost, and line losses as required in Decision No. 75859. For purposes of this Plan of Administration, and subject to future Commission proceedings, the combined adjustment for these three values is set at a Grid Factor Adjustment of 3.53 percent, as provided for in Decision No. xxxxx. This amount does not reflect an actual calculation of system conditions, and establishes no precedent for any future RCP or avoided cost calculations. While future Commission proceedings may establish methodologies for calculation of the adjustments, no changes will be made to this value until the conclusion of the next TEP general rate case.

7. Procedural Timeline

The Company will provide Commission Staff and other intervening parties with their annual RCP calculation no later than March 1 of each year. Interested parties will file comments to the Company's RCP calculation no later than April 1. Commission Staff will file its Report by May 15 and request that Staff's Report be considered in the June Open Meeting and be approved so that the new RCP calculation is effective on July 1.

8. Confidential Data

Portions of the data used to calculate the Company's annual RCP are competitively/highly confidential and cannot be released to the public. Competitively/highly confidential information will be made reasonably accessible to parties so that they may determine that such data supports the RCP calculation and that the RCP calculation complies with Commission orders. Competitively/highly confidential information includes cost and production data for facilities from which TEP purchases energy under a PPA agreement.

9. Schedules

Templates of the spreadsheet used to calculate the RCP are attached:

Schedule 1:	Annual Resource Comparison Proxy Calculation Summary
Schedule 2:	Solar Photovoltaic Grid-Scale Plant Data and Levelized Cost
Schedule 3:	Individual Plant Annual Cost ($/MWh)
Schedule 4:	Individual Plant Energy Production (MWh)
Schedule 5:	Individual Plant Revenue Requirement/PPA Annual Cost ($000)
Schedule 6:	Individual Plant Revenue Requirement/PPA Annual Cost including Production Tax Credits ($000)

Each of these schedules contains competitively/highly confidential PPA data as indicated.

Tuscon Electric Power Company
Schedule 1: Annual Resource Comparison Proxy Calculation Summary
= Competitively/Highly Confidential

			Highly Confidential				Highly Confidential
Year	Project #	Projects	Cost per MWh	1st Year Energy	Weight	Weighted Energy	Weighted Cost (1,000's)
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						

Confidential

Weighted Cost	
Energy	
Average Cost per MWh	
Grid Scale Adjustment	
Avoided Distribution and Transmission Facilities	
Resource Comparison Proxy (RCP)Cost per MWh	

Tuscon Electric Power Company
Schedule 2: Solar Photovoltaic Grid-Scale Plant Data and Levelized Cost

Project	RFP Year	Start Date	Start Year	Levelized Cost (Base Year)	MWH (1st Year)

= Competitively/Highly Confidential

Tuscon Electric Power Company
Schedule 3: Individual Plan Annual Power Cost ($/MWh)

Project	Levelized Cost per MWh	BY YEAR: 2011 through 2046
		= Competitively/Highly Confidential

Tuscon Electric Power Company
Schedule 4: Individual Plant Energy Production (MWh)

Discount Rate		
Project	Levelized Energy	BY YEAR: 2011 through 2046
		= Competitively/Highly Confidential

Tuscon Electric Power Company
Schedule 5: Individual Plant Revenue Requirement/PPA Annual Cost ($000)

Discount Rate		
Project	**Levelized Cost**	**BY YEAR: 2011 through 2046**
		= Competitively/Highly Confidential

Tuscon Electric Power Company
Schedule 6: Individual Plant Revenue Requirement/PPA Annual Cost Including Production Tax Credits ($000)

Discount Rate		
Project	Levelized Cost	BY YEAR: 2011 through 2046
		= Competitively/Highly Confidential