ORIGINAL

0000171237

RECEIVED

2016 JUN 24 P 3:25

AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE – Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322 **NOTICE OF FILING DIRECT TESTIMONY OF BRIAN A. SEIBEL ON BEHALF OF SOLON CORPORATION**

Intervenor SOLON Corporation, through undersigned counsel, hereby provides notice of filing the Direct Testimony of Brian A. Seibel in the above-described proceedings.

///

///

Arizona Corporation Commission
DOCKETED
JUN 24 2016
DOCKETED BY

DATED this 24th day of June, 2016.

GAMMAGE & BURNHAM, PLC

By _____

Camila Alarcon
Email: calarcon@gblaw.com
Attorneys for Intervenor SOLON Corporation

LAW OFFICES OF MICHELE VAN QUATHEM, PLLC

By _____ FOR

Michele L. Van Quathem
Email: mvq@mvqlaw.com
Attorneys for Intervenor SOLON Corporation

ORIGINAL and 13 copies filed on this 24th day of June, 2016 with:

Docket Control
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, AZ 85007

I hereby certify that I have this day served the foregoing documents on all of the parties of record in this proceeding a copy thereof, by electronic and/or regular mail, properly addressed with first class postage prepaid to:

Janice Alward
ARIZONA CORPORATION COMMISSION
1200 W. Washington
Phoenix AZ 85007
jalward@azcc.gov; rmitchell@azcc.gov; wvancleve@azcc.gov
cfitzsimmons@azcc.gov;
legaldiv@azcc.gov

Lawrence Robertson, Jr (U.S. Mail)
NOBLE SOLUTIONS
PO Box 1448
Tucson, AZ 85646

Dwight Nodes
ARIZONA CORPORATION COMMISSION
1200 W. Washington
Phoenix AZ 85007-2927
dnodes@azcc.gov

Meghan Grabel
OSBORN MALEDON, PA
2929 N. Central Avenue Suite 2100
Phoenix AZ 85012
mgrabel@omlaw.com

Thomas Broderick
ARIZONA CORPORATION COMMISSION
1200 W. Washington St.
Phoenix AZ 85007
tbroderick@azcc.gov

Barbara LaWall (U.S. Mail)
PIMA COUNTY ATTORNY'S OFFICE
32 North Stone Avenue, Suite 2100
Tucson AZ 85701

Kerri Carnes
ARIZONA PUBLIC SERVICE COMPANY
P.O. Box 53072, MS 9712
Phoenix AZ 85072-3999
kerri.carnes@aps.com

Thomas Loquvam
PINNACLE WEST CAPITAL CORPORATION
P.O. Box 53999, MS 8695
Phoenix AZ 85072
thomas.loquvam@pinnaclewest.com

Timothy Hogan
ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST
202 E. McDowell Rd. - 153
Phoenix AZ 85004
thogan@aclpi.org

Court Rich
ROSE LAW GROUP, PC
7144 E. Stetson Drive, Suite 300
Scottsdale AZ 85251
crich@roselawgroup.com

Cynthia Zwick
Kevin Hengehold
ARIZONA COMMUNITY ACTION ASSOCIATION
2700 N. Third St. - 3040
Phoenix AZ 85004
khengehold@azcaa.org;
czwick@azcaa.org

Daniel Pozefsky
RUCO
1110 West Washington, Suite 220
Phoenix AZ 85007
DPozefsky@azruco.gov

Gary Yaquinto
ARIZONA INVESTMENT COUNCIL
2100 North Central Avenue, Suite 210
Phoenix AZ 85004
gyaquinto@arizonaic.org

Travis Ritchie
SIERRA CLUB ENVIRONMENTAL LAW PROGRAM
2101 Webster Street, Suite 1300
Oakland CA 94612
travis.ritchie@sierraclub.org

Tom Harris
ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION
2122 W. Lone Cactus Dr. Suite 2
Phoenix AZ 85027
Tom.Harris@AriSeia.org

Michael Patten
Jason Gellman
SNELL & WILMER, LLP
One Arizona Center, Suite 1900
Phoenix AZ 85004-2202
mpatten@swlaw.com;
jhoward@swlaw.com;
docket@swlaw.com

Craig Marks
CRAIG A. MARKS, PLC
10645 N. Tatum Blvd., Suite 200-676
Phoenix AZ 85028
Craig.marks@azbar.org

Jeff Schlegel
SWEEP ARIZONA REPRESENTATIVE
1167 W. Samalayuca Dr.
Tucson AZ 85704-3224
schlegelj@aol.com

Michael Hiatt
Katie Dittelberger
EARTHJUSTICE
633 17th ST Suite #1600
Denver CO 80202
mhiatt@earthjustice.org;
kdittelberger@earthjustice.org

Ellen Zuckerman (U.S. Mail)
SWEEP SENIOR ASSOCIATION
1627 Oak View Ave.
Kensington CA 94707

C. Webb Crockett
Patrick J. Black
FENNEMORE CRAIG, PC
2394 E. Camelback Rd, Ste 600
Phoenix AZ 85016
wcrocket@fclaw.com;
pblack@fclaw.com

Bradley Carroll
TUCSON ELECTRIC POWER COMPANY
MC HQE910, P O Box 711
88 E. Broadway Blvd. MS HQE910
Tucson AZ 85702 – 0711
bcarroll@tep.com

Scott Wakefield
HIENTON & CURRY, PLLC
5045 N 12th Street, Suite 110
Phoenix AZ 85014-3302
swakefield@hslawgroup.com

Briana Kobor
VOTE SOLAR
360 22nd St. Suite 730
Oakland CA 94602
briana@votesolar.org

Kevin Koch (U.S. MAIL)
P.O. Box 42103
Tucson AZ 85733

Rick Gilliam
THE VOTE SOLAR INITIATIVE
1120 Pearl St, Ste 200
Boulder CO 80302
rick@votesolar.org

Bryan Lovitt (U.S. Mail)
3301 West Cinnamon Drive
Tucson AZ 85741

Steve Chriss
WAL-MART STORES, INC.
2011 S.E. 10th Street
Bentonville AK 72716
stephen.chriss@wal-mart.com

Nicholas Enoch (U.S. Mail)
LUBIN & ENOCH, PC
349 N. Fourth Ave.
Phoenix AZ 85003

Ken Wilson
WESTERN RESOURCE ADVOCATES
2260 Baseline Road, Suite 200

Boulder CO 80302
ken.wilson@westernresources.org

COASH & COASH
COURT REPORTING, VIDEO AND VIDEOCONFERENCING
1802 North 7th Street
Phoenix Arizona 85006

Dated at Maricopa County, Arizona, this 24th day of June, 2016

By Brad J. St. Clair

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

DOUG LITTLE – Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD AND TARIFF IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-01933A-15-0322

DIRECT TESTIMONY OF
BRIAN A. SEIBEL
ON BEHALF OF SOLON CORPORATION

June 24, 2016

Table of Contents

I. Introduction 1

II. Background 3

III. Rate Design Principles and Analysis 7

IV. Retroactive Net Metering Rider Changes 10

V. Three Part Rate Plans Are Confusing to Consumers 20

VI. Evaluating the Company's Rate Design Proposals 27

Finding 1: Three Part Rate Plans Result In Extremely High Levels of Uncertainty for All Residential Customers, With Or Without DG 42

Finding 2: The Company Must Release Commercial Customer 15 Minute Interval Data, and the Company Has Not Adequately Demonstrated Rate Plan Impacts to Commercial Customers, With Or Without DG 51

Finding 3: An Annual Ratchet Puts Insurmountable Pressure on Commercial Customers to Strictly Monitor Demand, and Ratchets Dis-Incentivize All DG, EE, and Storage Technologies 60

Finding 4: Low Usage Bills (<400kwh) Are Rarely Due to DG, Seasonal Homes, or Vacancies 66

Finding 5: The Company's Proposals Will Eliminate the Southern Arizona DG Solar Market 71

VII. Closing Statements 78

Exhibits A - K 80

I. Introduction

Q. Please state your name and business address.

A. My name is Brian A. Seibel. My business address is 3840 East Ajo Way, Suite 205, Tucson, AZ 85714.

Q. By whom are you employed and what is your position?

A. I serve as the President of SOLON Corporation (SOLON).

Q. Have you previously testified before the Arizona Corporation Commission?

A. No, I have not.

Q. Please describe your education, background and experience.

A. I hold a Bachelor's of Science in Business Management from the University of Arizona. I have held positions in the residential, commercial, and solar industry for 10 years spanning from financial analytics, solar production modeling, business development, electrical engineering, and executive management. I have built rate analysis and solar modeling tools for hundreds of customers in the following utilities:

Arizona

- Tucson Electric Power
- Unisource
- Arizona Public Service
- Salt River Project
- Trico

- Sulphur Springs Electric Cooperative
- Gila River Indian Community Utility Authority
- Navopache Electric

California

- Imperial Irrigation District
- Los Angeles Department of Water and Power
- Pacific Gas & Electric
- Sacramento Municipal Utility District
- Southern California Edison

Colorado

- Xcel Energy

Texas

- Austin Energy

Georgia

- Georgia Power

Utah

- Rocky Mountain Power

North Carolina

- Dominion
- Duke Energy
- Progress Energy

II. Background

Q. Who is SOLON Corporation?

A. SOLON is a turnkey commercial and utility scale solar developer and contractor headquartered in Tucson, Arizona. SOLON develops, designs, constructs, finances, and provides ongoing operations and maintenance services for solar customers throughout Southern Arizona. Based on more than fifteen years of solar panel manufacturing and power plant design experience, SOLON's solar project expertise spans a full spectrum of projects, from the 71 kW system at the Joint Technical Education District school (JTED), to the APS Cotton Center Solar Plant – a 21.7 MW single axis tracking system.

Q. Please describe SOLON's operations within the Company's service territory.

A. SOLON has been headquartered in Tucson, Arizona since its founding in 2007. Since its inception, SOLON has directly employed 225 Tucsonans to perform construction, engineering, manufacturing, sales, accounting, and administrative duties, in addition to local job creation via subcontractors and suppliers.

SOLON's continued local job creation is dependent on a regulatory environment that promotes renewable energy and a regulated utility that sends consistent signals to its consumers.

SOLON's customer base within the Company's service territory includes Southern Arizona elementary, middle, and high schools; colleges; municipalities; non-profits; utilities; and health care facilities. A brief list of SOLON customers is provided below:

- Tanque Verde School District
- Joint Technical Education District
- Pima Community College
- Fort Huachuca School District
- Pima County
- YMCA of Southern Arizona
- Marana Health Center
- Tucson Electric Power
- Unisource Energy Services
- Sulphur Springs Valley Electric Cooperative
- Trico
- University of Arizona

SOLON has constructed over 50 MW of commercial and utility scale projects throughout Arizona and over 25 MW within the THE COMPANY's service territory. SOLON's diverse project portfolio keeps it intimately connected with the metropolitan Tucson community.

Q. Why is SOLON intervening in this rate case?

A. SOLON is intervening with the hope its testimony sparks a transparent, real world discussion of the Company's proposal and the projected bill impacts using actual customer data.

SOLON is not intervening to blindly disagree with all of the Company's proposed changes; this is actually the first time SOLON has ever intervened in a rate case. After reviewing the Company's wide ranging and drastic proposals, local businesses are left with no other choice than to intervene and argue for fairness and gradualism. SOLON places a high value on its relationships within the local Tucson community, including its relationship with the Company.

Q. What are the purposes of your testimony?

A. The purpose of my testimony is to provide the Commission with a reliable analysis of the bill impacts to all residential and commercial customers, with and without Distributed Generation ("DG"). I will address the Company's proposal of retroactive rate making and its damaging, chilling effects on local businesses. I will argue the Company must release actual commercial customer interval data for analysis. I will evaluate the Company's current methods for estimating customer bill impact, provide suggestions for improvements, and depict the wide ranging results the Commission can expect should the Company's proposals be approved. I will offer detailed analysis and an opinion on how the Company's proposals stray from basic rate design principles. Lastly, I will address how I believe the Company's proposals will impact Southern Arizona's renewable energy market and the economy.

Q. What are the conclusions of your testimony?

A. My conclusions are as follows:

- Retroactive rate making, including Net Metering policies,
- The Company's modified data and customer profiles are misleading and unrealistic
- The Company's proposed three-part rate plans result in highly uncertain customer rates and unfairness
- Inadequate information exists to assess rate plan impacts to commercial customers
- Proposed ratchets result in bills wholly disassociated from actual customer demand
- Low usage homes are poorly understood and do not provide a foundation for the Company's proposals
- Gradualism is ignored
- The Southern Arizona solar market will be detrimentally impacted

Q. Do you use any trade terms in your testimony?

A. Yes. To avoid confusion, I have listed trade terms and my intended definitions in Exhibit B.

III. Rate Design Principles and Analysis

Q. What is your knowledge of the generally accepted principles of rate design?

A. First, Arizona's Constitution requires rates be "just and reasonable," with "no discrimination in charges." Ariz. Const. Art. XV, §12.

Second, well-recognized rate design principles are often referenced throughout the Company's testimony from James Bonbright's *Principles of Public Utility Rates*. In my testimony, I will address the below specific principles from Bonbright's book:

1. Rates should reflect the related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application
2. Rates should promote freedom from controversies as to proper interpretation
3. Rates should create revenue stability and predictability from year to year for the utility, but this stability and predictability should create a minimum of unexpected changes seriously adverse to existing customers
4. Rates should avoid "undue discrimination" in rate relationships

Third, as stated by the Commission, and documented later in my testimony, it is important to disallow any precedent for retroactive rate making in any form.

Fourth, I support the Arizona Corporation Commission's five-year strategic plan and its stated goals for utilities. The ACC's second goal is particularly applicable to the Company's application.

<u>ACC Utility Goals:</u>

1. To ensure that utility service within the Commission's jurisdiction is available to all consumers at authorized rates
2. **To promote the transition of the telecommunications and electricity generation markets from the current regulated monopoly structure to one of competition while ensuring safe and reliable service**
3. To maximize the Division's operating efficiency through modernization of electronic processing and enhancing the Division's information technology
4. To maintain public involvement, accessibility, and regulatory oversight by conducting workshops, forums, and community outreach programs

(Five Year Strategic Plan, Strategic Plan 2014-2019, Arizona Corporation Commission)

Q. In your opinion, how would you analyze proposed rate plan impacts and determine how closely the proposals adhere to generally accepted rate design principles?

A. The effort required for a responsible analysis will vary from utility to utility depending on the utility's level of sophistication, available resources, and how significantly their proposals vary from the current rate structures. The

Company in this rate case, Tucson Electric Power, is a sophisticated, mostly urban utility with a large, diverse customer base. The Company anticipates securing approximately $1B of yearly revenue selling energy to approximately 430,000 customers. The Company has shown its sophistication by installing advanced metering equipment for all customers. As I will show in my testimony, the Company's rate design proposals severely deviate from their current rate structures.

Given these facts, it is reasonable to expect the Company has access to their customer usage patterns on an hourly basis, and a responsible, fulsome analysis would include substantial customer data from the test year, unaltered in any way. I recommend at least 30% of each rate class be represented, with the selected customers evenly dispersed between the minimum and maximum load factor for each rate class.

Q: How many unaltered, actual customer hourly load profiles did the Company use in the analysis of their residential and commercial rate design proposals?

A. Zero.

IV. Retroactive Net Metering Rider Changes

Q. Do you have an opinion regarding the Company's proposal to retroactively change net metering for customers who installed DG after June 1, 2015?

A. Yes. Dallas Dukes, starting on page 2 of his Direct Testimony, proposes a new net metering rider applicable to net metering DG customers who submitted an approved interconnection application after June 1, 2015. While I support the Company's proposal to grandfather previous customers and keep existing customers on the R-4 Rider through May 31, 2035, I absolutely oppose changing any customer to the Company's proposed R-15 Rider before any new rates go into effect at the conclusion of this case or longer. The differences between the current R-4 rider and the proposed R-15 are so drastic, ratepayers deserve this topic to be heard by the Commission through due process.

While SOLON realizes the net metering rider may change in some way for future customers as a result of the Commission decision in this case, I absolutely oppose any change to the Company's rates that would be retroactive, and so should the Commission. Retroactive ratemaking, whether customers had notice of the potential for this dangerous precedent or not, clearly violates a core principle of rate design: rates should be fair, simple and free from controversy. Historically, the Commission has never supported retroactive rate making, and, in the interest of gradualism, should allow Tucsonans and the Southern Arizona solar market proper notification periods **after** changes to Net Metering or other policies have been heard

and approved by the Commission via the normal rate making process. I believe a proper, fair notification period is one year.

Q. Do you have any background information specifically related to retroactive Net Metering requests?

A. Yes. This case demonstrates why the Commission should not allow retroactive rate changes, including the Company's net-metering rider proposals.

On March 25, 2015, the Company applied to the Commission in Docket No. E-01933A-15-0100 for approval of a new net metering tariff for future net metered customers and approval of a partial waiver of the Commission's net metering rules. After significant concerns were expressed that the proposed changes should be determined as part of a rate case, the Company withdrew its application. However, the Company still posted a notice on its website of its intent to seek the same changes in an upcoming rate case. The notice implied the Company would seek retroactive rate changes to June 1, 2015, even though it had withdrawn its earlier application. The Company was ordered to change its disclosure language to remove the reference to the retroactive date in Commission Decision No. 75224.

If the Commission were to adopt the Company current proposal to retroactively change rates previously approved by the Commission as of June 1, 2015, such a change would send an unfair signal to both utilities and customers that utilities have the power and the Commission's blessing

to go back and change a customer's economic burden without a fair hearing before the change is applied.

Customers should have the right to rely upon Commission-approved tariffs until there is a new hearing and the tariffs are subsequently changed. The Commission should reject any retroactive change to the net-metering rider, and should make any future changes applicable only to customers that submit interconnection applications one year after the effective date of the Commission's decision at the end of this case.

Q. Why is it important to reject any retroactive changes to the net metering rider?

A. DG customers must make many long-term investment decisions based upon the information that is available to them at the time of installation, including both the certainty of the current approved tariff, the Commission's hearing process, and the uncertainty of future changes developed through the process. If the Commission adopts proposals that create instability and uncertainty in commission approved rates, it has a chilling effect on local investment in our community just as uncertain regulations damage any other industry.

Q. Is net metering critical to an economical solar project?

A. Without net metering, almost all of our customers have informed SOLON they cannot consider any future renewable projects because the financial viability are significantly reduced and unstable.

Q. Please explain how the Company threat of retroactive rate making has hurt local businesses.

A. I will start by explaining the process from a solar customer's standpoint using the example of the Company's disclaimer described above, starting at the submission of an interconnection application.

Q. What is an interconnection application?

A. One of the first steps in completing a solar project is submitting an interconnection application signed by the customer. A typical interconnection application requires basic information about the solar project such as the project location, size, other technical information about the solar equipment and whether the customer intends to select the Company's current Net Metering Rider. A copy of the Company's current interconnection application is attached to my testimony as Exhibit D.

Q. What did the Company change on the interconnection application after June 1st, 2015?

A. The Company added Attachment A to its interconnection application, which threatens customers with the possibility of net metering being taken away, even if their solar project was commissioned by the Company many months in advance of an ACC decision. The local solar industry, customers and SOLON watched as solar applications came to a screeching halt with the Company's continued pursuit of retroactive rate making and its updated interconnection application. The Company requires a customer to sign this acknowledgement before it will accept an interconnection application.

Q. Was any part of Attachment A, the new document attached to the interconnection application, confusing?

A. There are numerous facets of Attachment A that are vague and confusing, especially to potential solar customers. First, the application does not clearly specify what exactly the Company has proposed with regard to the net metering rider, how it would affect solar savings, and the effective date of the proposed changes. Second, the notice especially as it originally appeared on the Company's website implied the concept of retroactive rate making – a concept that caused a great deal of uncertainty. It is deeply disturbing for a regulated utility to distribute, and require a customer to sign, a disclaimer acknowledging the possibility of retroactive rates or other unexplained changes.

Q. Has the Company's retroactive rate request damaged SOLON's business since June 1st, 2015?

A. Yes, SOLON and many other local companies that are involved in the solar industry have been affected. It will continue to be challenging until this case is resolved, especially given the Company's continued intent to pursue a retroactive change in the net metering tariff and reduce solar installations. Although the concept of retroactive rates is unprecedented and harmful to business, customers do not know yet if the Commission will adopt the Company's proposal. If one of our customers were to submit an interconnection application after June 1st, 2015, complete construction, and energize the solar project prior to the final decision in this matter, the project could then have net metering taken away well after the project's completion if the Company's retroactive request was approved by the ACC.

Even if a customer submitted an interconnection application on or subsequent to June 2nd, 2015, we often do not receive customer approval to begin construction activities because the Commission's decision remains unknown. Remember, the Company forces customers to sign Attachment A in order to have a completed interconnection application.

The Company's actions throughout 2015 and 2016 have effectively put solar projects on hold by threatening questionable net-metering proposals, such as those found in Attachment A.

A small number of customers have chosen to move their solar projects forward even though there is the possibility that the ACC could approve the Company's retroactive request. It is unfathomable that customers who submitted an interconnection application after June 1st, 2015 and completed their project shortly thereafter would have net metering taken away from them approximately 18 months or longer after a decision is made by the ACC.

Q. Has the number of new commercial interconnection applications been reduced since the Company now requires prospective commercial solar customers to sign Attachment A and pursues retroactive changes to June 1st, 2015?

A. Yes. According to the Company, there were 158 commercial interconnection applications received and approved in the first 6 months of 2015. **In stark contrast, in the second 6 months of 2015, when the**

Company required customers sign Attachment A, there were <u>14 approved commercial interconnection applications</u>, a decrease of over 91%. (http://www.pagregion.com/Default.aspx?tabid=946, Documents for 05-12-2016, Presentation TEP Report)

Q. Has the ACC publically addressed the issue of retroactive rate case making in the matter of Tucson Electric Power?

A. Yes. However, the Company continues to boldly seek retroactive rates and force customers to sign documents acknowledging the Company's pursuit of retroactive rate case making regardless of the unlikelihood it is approved. Below is an excerpt from an ACC open meeting on August 18th, 2015 in the matter of Tucson Electric Power. For reference, Ms. Alward is the Chief Counsel, Legal Division.

E-01933A-15-0100 Tucson Electric Power 08-18-2015 Page 18

COM. Little:

15 In your experience, Ms. Alward, how many times
16 has the Commission approved retroactive rate structures?
17 And I'm not looking for a precise number, but is it
18 frequent, infrequent, nearly, nonexistent? What is your
19 assessment?
20 MS. ALWARD: I would have to say in all of the
21 many years probably it's nearly nonexistent.
22 COM. LITTLE: So what you're really saying is,
23 is that there is no precedent for -- there is no
24 meaningful precedent for retroactive rate changes in
25 this Commission?

E-01933A-15-0100 Tucson Electric Power 08-18-2015 Page 19

1 MS. ALWARD: That's true. And typically, the
2 case law across the country, as well as here, would be
3 against retroactive rate making as a rate making
4 principle.
5 COM. LITTLE: It would almost, in fact, be an

ex-postfacto type situation, would it not?

MS. ALWARD: Yes, it could be viewed that way.

COM. LITTLE: Okay. Thank you.

CHMN. BITTER SMITH: Thank you, Commissioner Little.

Commissioner Burns.

COM. BOB BURNS: Just a couple of points to follow up on Commissioner Little's comments. First of all, I don't know that we used -- I don't think we used the word "approve" in that program, TEP program. It wasn't a -- it wasn't a vote to approve, I don't believe. I could be wrong, but I don't believe that was it.

The other thing is on the discussion of whether or not the Commission ever does a retroactive rate increase, I agree that it probably doesn't happen even. But the message that gets sent out if the -- if the utility is sending out to their customers a notice that they're going to go into a rate case and they're going to consider asking for a retroactive rate

increase, that's a word that everybody -- or a notice that everybody reads and sees. They don't hear and understand that it doesn't really happen at the Commission.

I mean, we don't have that newsletter ability, I guess, is what I'm trying to say. So they have a -- they have a much -- much easier method of notifying the public, even if it's not something that might come to pass, so --

CHMN. BITTER SMITH: Thank you, Commissioner Burns.

Commission Little?

COM. LITTLE: Yeah, I'd just like to echo the comments of Commissioner Burns.

I think, in the absence of any specific rulemaking, I think, you know, I would agree that it is probably inappropriate to have companies putting out grandfather dates that says this is the date we're going

19 to stick in the sand and it's going to be a retroactive
20 increase.
21 And I say that because of precisely what
22 Ms. Alward just shared with us. It's inappropriate to
23 do that because it simply has no precedent at the
24 Commission. And I -- I would strongly encourage all
25 utilities in the state of Arizona, not just the electric

E-01933A-15-0100 Tucson Electric Power 08-18-2015 Page 21

1 utilities, but all utilities to avoid trying to
2 communicate that message to their ratepayers.
3 CHMN. BITTER SMITH: Thank you, Commissioner
4 Little.

Q. What do you recommend with regards to the Company's Net Metering proposals.

A. The concept of utilities proposing anything at any time with the possibility that it is approved retroactively is dangerous, unprecedented and boldly usurps the Commission's authority. SOLON's clients and many others have expressed apprehensiveness about the Company's actions and are unable to plan sufficiently for the future. We request that the Commission include a strong rejection in its ultimate decision of the Company's proposal to retroactively change the net metering tariff. Further, to provide customers with more stability in their investment decisions, the Commission should require the Company to notify the public of any Commission-approved net-metering tariff modifications one year before any changes take effect. This will send a strong message that the Commission expects rate changes to occur through a rate case process where all proposals are fairly considered rather than through threats released at any time. This will provide greater certainty to customers

seeking to make investments by providing them with advance notice of accurate, actually-adopted changes in the net metering tariff. Consumers, schools, businesses, and government agencies develop plans and investments far more than a year in advance; predictability and consistency are critical for their planning, and for fostering continued local economic investment.

Q. Do you have an opinion on the Company's proposed Renewable Credit Rate (RCR)?

A. Yes, there are two main problems with the Company's proposed RCR.

First, the Company has proposed to reset the RCR annually (Hutchens 25:5). This will inject uncertainty into the market, as it is impossible for a customer to make investments in DG, calculate long term savings and cost, or finance a DG system over 20+ years when the Company modifies the value of the solar electricity generated (RCR) every year to an unpredictable value.

Second, the Company's proposed RCR does not take into account any of the facts currently being heard in the Value of Solar docket.

I recommend the Company maintain its current Net Metering policies until all the facts from the Value of Solar docket can be heard.

V. Three Part Rate Plans Are Confusing to Consumers

Q. Do you have concerns about the price signal statements proposed by the Company regarding the three-part rate plan?

A. Yes. David G. Hutchens direct testimony states the Company believes a three-part rate design "allows customers to reduce their bills by managing their energy consumption through EE or DG". (Hutchens 19:6)

Dallas J. Dukes direct testimony states that a demand charge should provide customers with a proper price signal to "make proper usage and equipment purchase decisions that would reduce that portion of their bill". (Dukes 17:20)

Despite the Company's statements throughout its application, the vast majority of consumers and businesses do not know the difference between a kWh and a kW, let alone how to reduce their peak demand or kW usage. These statements ring hollow where the vast majority of their customers lack information to analyze their demand and tools to manage their demand. The Company's proposals are premature for their market.

Significantly reducing a demand charge is not as simple as finding the highest kW peak and turning off an appliance or two, as this will only reduce the demand charges to the next highest peak. Three part rates no not adhere to Bonbright's simplicity, understandability, public acceptability and feasibility of application.

Q. What is a typical method average consumers can use to "make proper usage and equipment purchase decisions" with regards to energy efficiency of similar appliances?

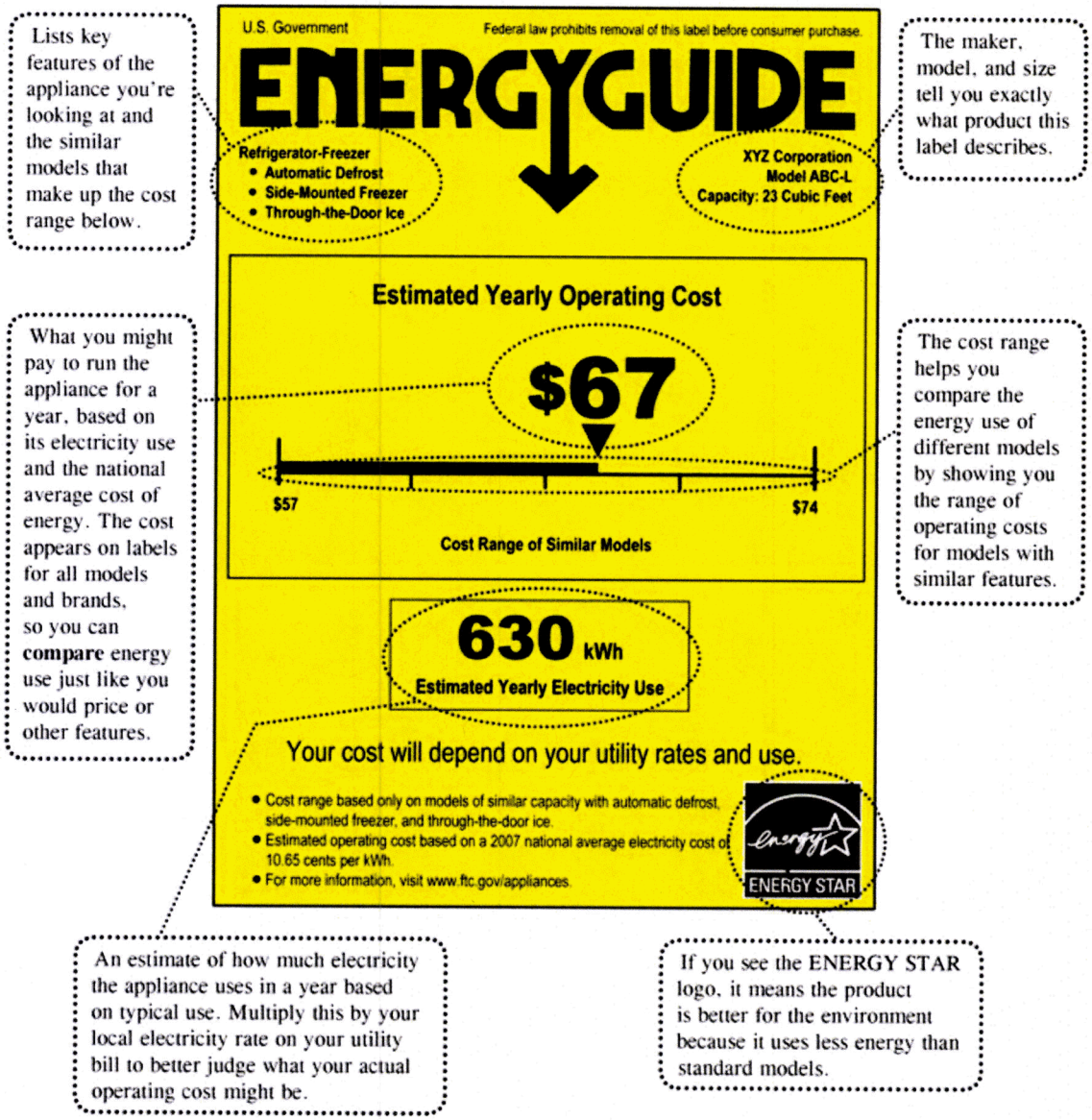
A. A common practice is to review an appliance's EnergyGuide label from the Federal Trade Commission (FTC). Appliance energy labeling was mandated by the Energy Policy and Conservation Act to help consumers compare kWh load and potential annual electrical cost and usage amongst similar appliances.

Q. Do EnergyGuide labels provide consumers with information regarding three part rates, specifically demand and kW?

A. No. These labels are a prime example of the information average consumers use to influence appliance purchasing and household electrical usage habits. However, these labels do not provide any information regarding the potential effects to their kW demand charges. EnergyGuide labels are used for such equipment and purchase decisions as varied as the following:

> Boilers, central air conditioners, clothes washers, dishwashers, freezers, furnaces, heat pumps, pool heaters, refrigerators, televisions, water heaters, window air conditioners

For reference, below is an example of an EnergyGuide label from the FTC.



(https://www.consumer.ftc.gov/sites/default/files/pictures/0072-energy-guide-label.jpg)

This example label uses 10.65 cents per kWh to estimate the annual energy cost of $67. Consumers will have no idea how this appliance will affect potential demand charges, and will make misinformed usage and equipment purchase decisions.

Q. What information and analysis is needed to understand, analyze and reduce a customer's peak demand?

A. A homeowner would need to monitor every hour of electricity usage for the month (730 hours per month on average of "interval data") and then know how to analyze that data to determine when the home is using the highest kW and what is their next highest kW. This data must be incorporated and compared to the electrical usage and timing of all consumer electronics, appliances, heating and air conditioning units, lighting and anything else consuming electricity. The homeowner would need to understand not only how many kWh each item uses but also its peak kW usage and demand causation. Even if a homeowner was able to compile, understand, and analyze all of this data, they would then have to create a plan of which household electrical items must not be used at the same time in order to reduce their demand charges.

For example; a resident may be able to use their TV and microwave at the same time, but if they turn on too many additional lights at the same time, their kW demand charge could increase for the entire billing month. If this event only occurred once during an entire month and the resident never turned on another light or electrical appliance for the entire month, their demand charge would remain unchanged due to that single event, even if it did not coincide with the Company's grid peak demand. If the homeowner's air conditioning unit coincidentally turned on at the same time during this single monthly event, their kW demand charges could skyrocket. By the time the electric bill arrives, a homeowner experiencing

a high demand charge in these situations would have no way to know what action caused the increase.

Q. Do all of the Company's customers have the ability to obtain hourly electrical usage or "interval data" if they wanted to attempt a kW analysis?

A. No. Only a limited amount of customer's meters at the beginning of the Company's test year had the ability to track and record kW interval data. Although the Company is working vigorously to install these meters for everyone, a full 12 months of previous kW data is needed before a consumer can even attempt a demand analysis. The company will not have this data prior to the conclusion of this case. DG customers forced onto three part rate plans will have no way to evaluate their billing impacts, and neither will the Company.

If a consumer happens to have an updated meter, if the Company has recorded a full 12 months of demand data, and if the consumer seeks to acquire their 12 months of demand data, then the consumer still has to contact the Company and wait for the information to be collected and sent to them. Adding insult to injury, the Company proposes to charge customers on an hourly basis for collecting and sending the data, if requested more than once in any 12-month period (Jones 74:21).

Q. How does this relate to the Company's stated goals of sending appropriate signals to help customers make informed decisions?

A. The Company contradicts itself in the response to SWEEP's Discovery Request 2.15 as follows:

"TEP has not conducted any analyses or reviewed previous studies to determine if a three-part rate is superior to a two-part time-of-use rate in reducing peak demand. TEP has not conducted or reviewed such a study because reducing peak demand is not the primary objective of TEP's proposed three-part rates for residential and small general service customers. While peak demand reduction may be a benefit of the proposed three-part rate, the main objective of TEP's proposal is to better align cost recovery with how costs are incurred."

SOLON fundamentally objects to the Company's premature three-part demand rate plans when the Company has not completed a realistic analysis of how it will impact their consumers.

Q. What kind of analysis has been performed to understand demand charge impacts, ratchets and three-part rate plans effects on customers?

A. SOLON agrees with the Company that demand charges have not historically been billed, that it is "essential that we had a complete understanding of the billing determinants as we modified provisions" (Jones 34:12), and that "a thorough analysis must be performed to best ensure that the impacts on the customer are understood" (Jones 35:22).

These statements are compelling but it is obvious the Company did not attempt to understand its own proposals on individual customers when it admits in SWEEP discovery request 2.15 that "TEP has not conducted any analyses or reviewed previous studies to determine if a three-part rate is superior to a two-part time-of-use rate"

It is apparent that the Company is proposing dramatic rate structure changes without any analysis or examination of customer impacts. As mentioned earlier in my testimony, the Company has not used the actual data from a single real customer to understand the potential impacts.

Again, SOLON objects to the Company's premature three-part demand rate proposals when the Company has not completed a basic analysis of how it will impact their consumers.

Q. What would you recommend if the Company truly wanted to send proper price signals and adhere to Bonbright's principles?

A. Properly structured, fair time of use (TOU) rate plans, with a detailed analysis using actual consumer load profiles that truly adhere to Bonbright's principles. TOU plans are easy to understand and can help people reduce their peak kW load when it coincides with the Company's overall peak demand. The Company can send clear price signals so customers know at what time they should use less electricity. Further, this supports gradualism as it improves on an existing and understood concept.

VI. Evaluating the Company's Rate Design Proposals

Q: What are the mechanisms the Company has proposed to alleviate their alleged fixed cost recovery issue, which they largely attribute to vacant homes, seasonal homes, EE, and DG solar customers?

A: In a wide ranging, aggressive, and unprecedented proposal, the Company proposes the following:

1. Retroactively remove existing Net Metering policies
2. 59% increase in the DG Lost Fixed Cost Recovery Rider cap for all ~435,000 customers
3. 41% increase in the EE Lost Fixed Cost Recovery Rider cap for all ~435,000 customers
4. 100% increase in the monthly fixed charge for all ~355,000 residential customers
5. 71% increase in the monthly fixed charge for all ~30,000 SGS commercial customers
6. Establish a new commercial customer MGS three-part rate plan, forcing ~4,000 businesses (page 37, line 20 of Craig Jones) onto the MGS rate plan that are currently under a two-part rate plan
   - Each of the ~4,000 businesses will see a 128% increase in their monthly fixed charges
7. Establish a 75% demand ratchet with a 12 month look back for all MGS customers. Again, the vast majority of these customers have never been billed for demand
8. If any MGS customer's peak 15-minute demand exceeds 250kW, they would be instantly, without their consent, forced into the LGS

rate plan (the LGS rate plan increases their annual fixed cost from $480 to $12,000, a 2,400% increase). The new LGS customer would then have to establish a demand of less than 250kW for 12 consecutive months to be eligible to return to the MGS rate (Jones 47:8-12)

9. 29% increase in the monthly fixed charge for all LGS customers
10. Create a residential R-01 Demand three-part rate plan and require all new DG customers to remain on that rate plan as long as they have a solar array
11. Create a commercial SGS Demand three-part rate plan and require all new DG customers to remain on that rate plan as long as they have a solar array
12. Institute a Renewable Credit Rate (RCR) to purchase excess DG solar energy exported to the Company's grid at an uncompetitive rate. The Company proposes the right to change the RCR every year, at their discretion
13. Charge customers a new hourly fee for more than one historical usage request
14. Adjust Riders from a volumetric kWh charge to a percentage of the total bill

Q: What type of "Net Metering" policy is the Company proposing?

A: The Company is proposing to purchase all excess solar kWh exported to the Company's grid on an instantaneous basis at the "Renewable Credit Rate" of $0.0584/kWh. While the company often refers to this program as "Net Metering" or even "Hourly Net Metering", the industry refers to this program as a wholly different concept named "Net Billing". See Exhibit B – Trade Terms for a differentiation of these concepts.

Q: If any person or business wanted to evaluate the economics of a solar project with the Company's net metering proposal, would they need access to an instantaneous solar production profile and a historical instantaneous usage profile?

A: Yes. Since the Company is proposing, as its net metering policy, to purchase all excess solar kWh exported to the Company's grid on an instantaneous basis at the "Renewable Credit Rate" of $0.0584/kWh, any analysis using hourly, monthly, or annual data would be purely speculative and inaccurate. According to the Company's response to SOLON discovery request 2.10(c) and 2.10(d), the Company does not have any meters installed in their service territory that log instantaneous customer usage or solar production.

Q: What interval load data has the Company provided in their analysis?

A: I will begin with the residential load data. The Company has provided 17,296 hourly load profiles beginning July 1st, 2013 and ending June 30th, 2015 ("Sample Data"). The Sample Data represents approximately 5% of the Company's residential customer base. However, upon further review,

numerous meters were missing significant data. See the below table for a summary of the number of meters missing data.

Missing 2014 Data %		# of Hourly Profiles
Min	Max	
0.0%	0.0%	13,529
0.1%	5.0%	42
5.1%	10.0%	90
10.1%	15.0%	42
15.1%	100.0%	2,757

Despite having 19,110 AMR meters installed for commercial customers at the start of the Test Year that log usage in 60-minute or 15-minute intervals (SOLON DR 2.10), the Company has not provided any hourly data for commercial customers of any size, despite requests from SOLON and Staff (SOLON DR 3.2, Staff DR 20.08).

Q: Did you remove any of the 17,296 residential load profiles in your analysis?

A. Yes. I removed any profiles that had greater than 5% of its data missing. Additionally, I only used the 12 months of January 2014 through December 2014. Since the Company's provided rate plan modeling spreadsheets begin in January, it is critical to have a contiguous 12 month dataset beginning in January. If I used data strictly from the test year (June 2014 through May 2015), any customer usage patterns in at the end of May

would not carry though. If this data remained in my analysis, the value of the solar chart in Finding 5 of my testimony would be artificially reduced, thus artificially strengthening my testimony in that section.

Q: Did the Company use any of the 17,296 unaltered, actual customer load profiles in their analysis of net metering, a Renewable Credit Rate, or customer bill impact with new two-part and three-part rate plan proposals?

A. No.

Q: What load data did the Company use in their residential analysis?

A. First, the Company took the Sample Data (the 17,296 residential hourly profiles) and generated average **monthly** load profiles for five different customer percentiles. Below is a breakdown of the Company generated average **monthly** residential load profiles:

Company Provided Monthly Residential Load Profiles				
Name	**Percentile**	**Monthly kWh**	**Monthly kW**	**Average Monthly Load Factor**
XS	25th	212	1.89	15.4%
SM	40th	518	3.85	18.4%
MED	75th	956	5.62	23.3%
LG	90th	1,352	6.94	26.7%
XL	98th	2,094	9.10	31.5%

Second, the Company took the Sample Data and generated average **hourly** load profiles for five different customer percentiles. The hourly values

appear to be averaged amongst a large group of residential customers. By averaging in this fashion, individual customer peaks unique to each customer are smoothed and not accurately represented. These unique customer peaks are paramount to a responsible analysis. Below is a breakdown of the Company generated average **hourly** load profiles:

Company Provided Hourly Residential Load Profiles				
Name	**Percentile**	**Monthly kWh**	**Monthly kW**	**Average Monthly Load Factor**
XS	25th	196	0.51	52.2%
SM	50th	506	1.40	49.5%
MED	75th	1,009	2.78	49.8%
LG	90th	1,703	4.29	54.4%
XL	95th	2,258	5.43	57.0%

When the Company averages numerous load profiles together, the provided hourly profiles result in abnormally high load factors. Higher load factors represent a flatter load profile, which generally falsely conclude reduced impacts on some customers subject to three-part rate structures.

Third, the Company took each hour from the average **hourly** load profiles and multiplied them by the following ratio:

$$\frac{Peak\ Demand\ (by\ Month)\ from\ Average\ Monthly\ Profile}{Peak\ Demand\ (By\ Month)\ from\ Average\ Hourly\ Profile}$$

The Company performed this calculation to shoehorn the average **hourly** load profile to fit the monthly load factors.

These calculation steps result in five heavily modified load profiles to analyze the billing impacts to 350,000+ residential customers.

Q: Did the Company provide any DG solar generation profiles?

A: Yes. The Company generated example hourly data for one south and one west facing DG solar project using the System Advisor Model (SAM). The Company then heavily and inaccurately scaled each hourly profile to align with customer usage for each of the five previously described load profiles. From there, only the south facing (highest producing annually) profiles were used.

Additionally the company provided one monthly profile for each of the five load profiles previously described. These monthly profiles are substantially different than the hourly profiles provided, and closely align with the Company's modified load profiles. Following is a summary of the monthly discrepancies:

COMPARISON OF COMPANY PROVIDED HOURLY AND MONTHLY SOLAR PROFILES (KWH)

(HP = Hourly Profile, MP = Monthly Profile)

	XS		SM		MED		LG		XL	
	HP	**MP**	**HP**	**MP**	**HP**	**MP**	**HP**	**MP**	**HP**	**MP**
Jan	178	182	445	405	800	699	1,067	932	1,334	1,394
Feb	164	148	409	304	736	525	982	687	1,227	1,067
Mar	217	178	543	358	978	573	1,304	773	1,630	1,183
Apr	232	176	580	367	1,043	579	1,391	797	1,739	1,210
May	231	204	577	454	1,038	703	1,384	975	1,730	1,459
Jun	213	387	533	817	959	1,177	1,279	1,602	1,599	2,277
Jul	206	180	515	564	927	1,079	1,235	1,640	1,544	2,210
Aug	211	155	528	533	950	1,009	1,267	1,519	1,583	2,048
Sep	199	144	496	500	894	924	1,192	1,384	1,489	1,864
Oct	197	109	492	366	885	692	1,180	1,012	1,475	1,478
Nov	182	104	455	298	818	564	1,091	799	1,364	1,211
Dec	171	155	429	385	772	706	1,029	958	1,286	1,440

Q: How did the Company incorporate the hourly and monthly DG solar generation profiles into their analysis?

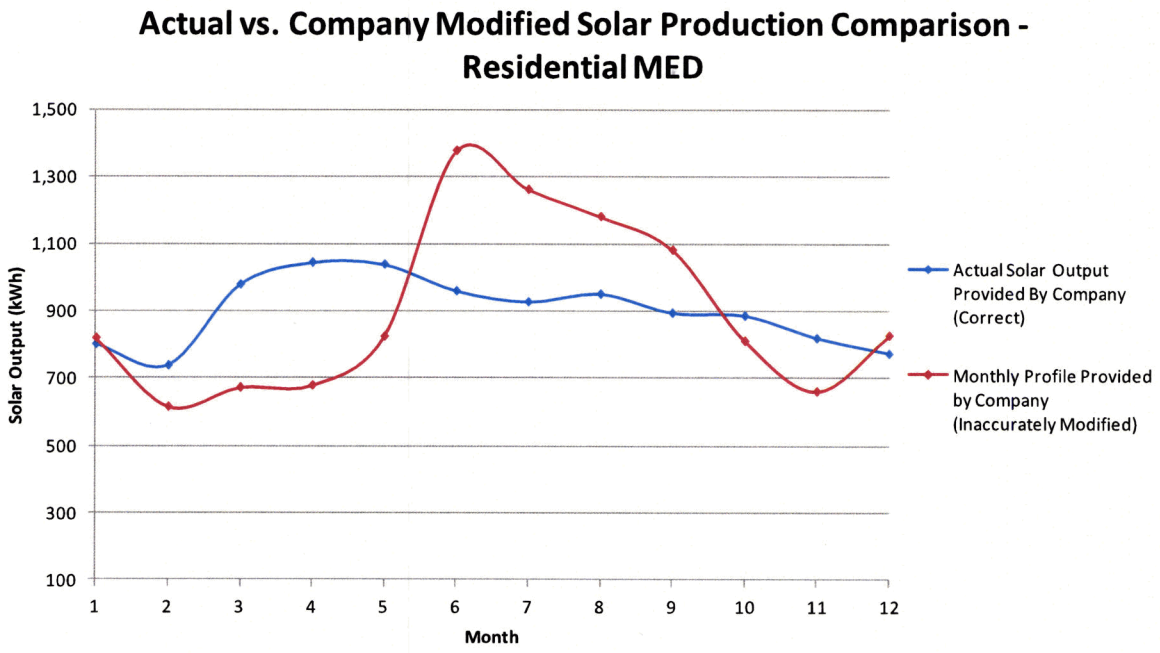
A: First, the Company scales each hour to match the DG solar array to 100% of the annual usage.

Secondly, the Company takes each hourly value and multiplies it by the following ratio:

$$\frac{Total\ Solar\ Output\ from\ Company\ Provded\ Monthly\ Profile}{Total\ Solar\ Output\ from\ Company\ Provded\ Hourly\ Profile}$$

As shown, the Company provided monthly profile is not indicative of any individual solar array and in no way resembles any solar array installed in Southern Arizona <u>because the Company provided profile is physically impossible</u> (see Exhibit A).

The results are five artificially modified solar profiles that almost exactly align with the Company's modified load profiles. These are the profiles used in all of the Company's analysis. Following is one graphical example of this severe alteration to the solar profiles (MED customer shown).



Q: How does a closely aligned solar and load profile impact a Net Metering analysis?

A: If a customer's load and solar profile are closely aligned, the results are the following:

- Solar exported to the grid is artificially minimized
- Solar energy purchased by the Company at the RCR rate, ~50% of the residential retail rate, is artificially minimized
- Solar energy purchased by the Company at the MCCCG rate at the Net Metering Reset Month (October) is artificially minimized

Each of these items will reduce the perceived importance of net metering to a DG customer and help support Carmine Tilghman's and Dallas Dukes'

broad statement "Under this proposal, DG customers would still see significant savings on their electric bills" (Carmine 11:3, Dukes 22:16).

Q: Please comment on the Company's residential rate analysis in the file "2015 TEP R-01 Demand-PRS" and its commercial rate analysis in the file "2015 TEP GS-10 Demand-PRS". Did you find inaccuracies, discrepancies, or poor analysis in these files?

A: My summary on the Company's residential rate and commercial rate analyses are as follows:

1. ***Issue:*** As previously described, the hourly solar profiles are heavily modified to physically impossible values to more closely align with assumed monthly usage profiles.

   Result: This artificially reduces the impact to customers' bills by removing net metering.

2. ***Issue:*** As previously described, instead of using the Company provided 17,260 usage profiles from actual customers, the Company uses questionable and misrepresentative methods to arrive at five average usage profiles as the sole basis for their analysis provided in Dallas Duke's and Craig Jones' testimony.

   Result: The average, artificial usage and demand profiles smooth out individual customer demand peaks and severely mitigate the impact of new demand charges when switching from a volumetric rate plan to a

demand based rate plan. Additionally, they skew any analysis of net metering and RCR credits.

3. ***Issue:*** The Company does not use their own annual net metering reset policy at the end of September. Instead, the Company's analysis used December.

   Result: This artificially alters the benefits of net metering. This inaccuracy will alter customers expected utility bills in varying ways. Regardless, the assumption does not match the Company's net metering policies.

4. ***Issue:*** The Company's analysis of PV power exported to the grid and consumed by the customer is rooted from hard coded values that ignore accurate, calculated results from the Company's included hourly solar and usage profiles.

   Result: The artificial solar profiles reduce the impact of new demand charges when switching from a volumetric rate plan to a demand based rate plan. Additionally, they skew any analysis of net metering and RCR credits.

5. ***Issue:*** The Company's analysis includes five customer load scenarios, all of which are average load scenarios, as mentioned in Issue 2. The Company did not run its model with any of its customers' load profiles

when analyzing the impact when switching from a volumetric rate plan to a demand based rate plan.

Result: In previous rate cases, the Company proposed modifications to their fixed, volumetric, and percentage based charges. These types of charges can be more accurately modeled with average load profiles. IE if the Company proposed a 10% increase to their volumetric charges, it is reasonable to assume that each customer type (small, medium, large) would see approximately 10% increase in their bill, monthly usage remaining constant. However, when transitioning customers to a three part rate plan, average profiles do not capture the wide range of unique usage and demand profiles, which is critical to evaluate bill impact when switching to a demand based rate plan.

Q: What are your proposed revisions to the aforementioned Excel files to address these issues?

A: Please see Exhibit A for all proposed revisions.

Q: After performing the modifications to the Company's models, were you able to run each Company provided residential hourly load profile, unaltered in any way, through the Company's model?

A: Yes. For each of the 17,296 residential hourly load profiles, I captured the following data points:

- Annual usage (kWh)
- Usage, by month (kWh)
- Peak demand before solar, by month (kW)
- Peak demand after solar, by month (kW)
- Solar production, by month (kWh)
- Resulting customer bill for the following scenarios:
    - Current R-01, No PV ($)
    - Proposed R-01, No PV ($)
    - Proposed R-01 Demand, No PV ($)
    - Current R-01, with PV, with Net Metering ($)
    - Proposed R-01, with PV, with Net Metering ($)
    - Proposed R-01, with PV, with RCR ($)
    - Proposed R-01 Demand, with PV, with Net Metering ($)
    - Proposed R-01 Demand, with PV, with RCR ($)
- Number of blank hours
- Number of zero usage hours
- Number of consecutive 720 hours with zero usage (1 month)

Q: Approximately how long did it take you to run each hourly residential profile and record the above data for all 17,296 hourly load profiles?

A: The process took 50 minutes.

Q: Did you require any advanced computing software or expensive computing power to perform this analysis?

A: No. All analysis was performed in Microsoft Excel on a consumer grade Lenovo ThinkPad X1 Carbon laptop purchased in May 2014.

Q: Was any part of this analysis unduly burdensome?

A: No. This analysis is simple and critical to understand the full impact of the Company's wide ranging, aggressive, and unprecedented proposals.

Q: What were your findings?

A: My high level findings are as follows:

1. Three-part rate plans, as structured, ignore gradualism and result in extremely high levels of uncertainty for all residential customers, with or without DG
2. The Company must release commercial customer 15 minute interval data, and the Company has not adequately demonstrated rate plan impacts to commercial customers, with or without DG
3. An annual ratchet puts insurmountable pressure on commercial customers to strictly monitor demand, and ratchets dis-incentivize all DG, EE, and storage technologies
4. Low usage bills (<400kWh) are rarely due to DG, seasonal homes, or vacant homes
5. The Company's proposals will eliminate the southern Arizona solar market

Each finding is described in detail on the following pages.

FINDING 1: THREE PART RATE PLANS RESULT IN EXTREMELY HIGH LEVELS OF UNCERTAINTY FOR ALL RESIDENTIAL CUSTOMERS, WITH OR WITHOUT DG

Q: Please summarize the purpose and conclusions of this section.

A: Using actual residential load data provided by the Company, I will show three-part rate design is premature, highly volatile, and the Company has not adequately presented its wide ranging impacts. Given the high level of uncertainty around three-part rate structures, no customer class should be discriminated against and forced into three part rates.

Q: Did the Company provide any analysis to show the wide ranging impacts of demand charges to residential customers with and without DG, particularly those with lower than average load factors?

A: No. Of the 17,296 hourly profiles provided by the Company, zero were included in their testimony. Instead, as previously described, four highly modified profiles were used. No facts were presented showing expected minimum, maximum, and average bills under three part rates for any customer class.

Q: What analysis did you complete to evaluate residential three part rates?

A: First, I took each of the 17,296 hourly profiles (less the incomplete profiles as described earlier in my testimony) and calculated their expected bill under the current R-01 rate plan. Second, I calculated their expected bill under the proposed R-01 rate plan. Third, I calculated their expected bill

under the proposed R-01 Demand rate plan. Fourth, I calculated each rate plan a second time assuming the customer has a DG solar array that generates 100% of the customer's annual usage, to match the Company's assumptions.

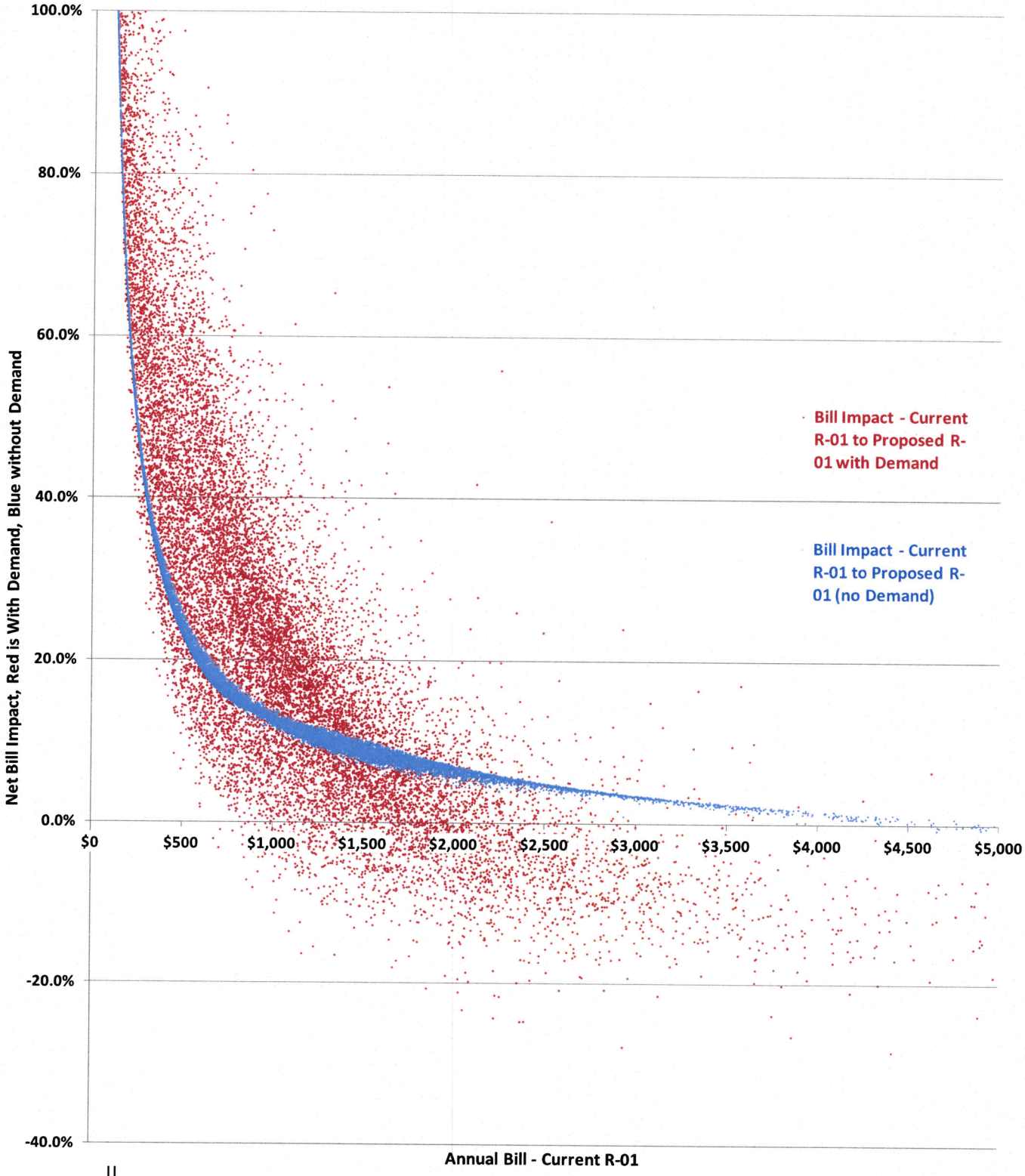
Q: The Company has not currently proposed a three part rate structure for all residential customers. Why is this analysis important or relevant?

A: I understand the Company has not currently proposed to force all residential customers to a demand based rate plan. However, in other similar electric utility rate cases within Arizona, this concept has been introduced. As a critical component to rate design is to be non-discriminatory, it is important to understand the wide ranging effects of three part rate design on all residential customers, with and without DG. As described later in my testimony, commercial interval data is alarmingly absent from this rate case, and the conclusions from this analysis are directly applicable to most commercial customers.

Q: Do you have any visual depictions of your findings?

A: Yes. Please see the following pages.

Bill Impact - Current R-01 to Proposed R-01 and R-01 Demand, no PV



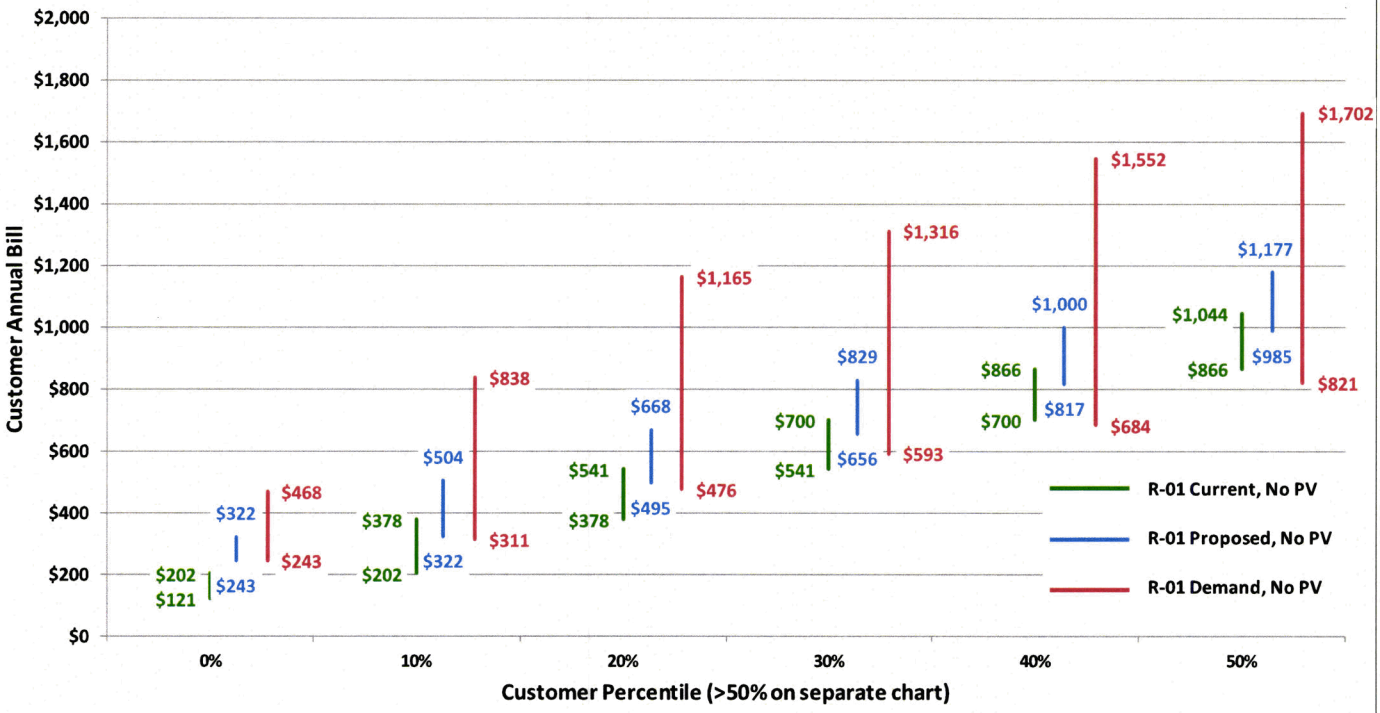
Q: Please explain the preceding graph and outline your conclusions.

A: **Explanation:** There are two dots for each Company provided residential load profile. One blue dot represents the percentage increase the customer would experience when transitioning from the current R-01 to the proposed R-01 rate plan without any demand charges. One red dot represents the percentage increase the customer would experience when transitioning from the current R-01 to the proposed R-01 rate plan with demand charges. Strictly for visual reasons, the 1,038 customers with greater than 100% bill increase have been excluded, and customers with an annual bill greater than $5,000 have been excluded. This chart was created using the actual, unmodified customer data provided by the Company.

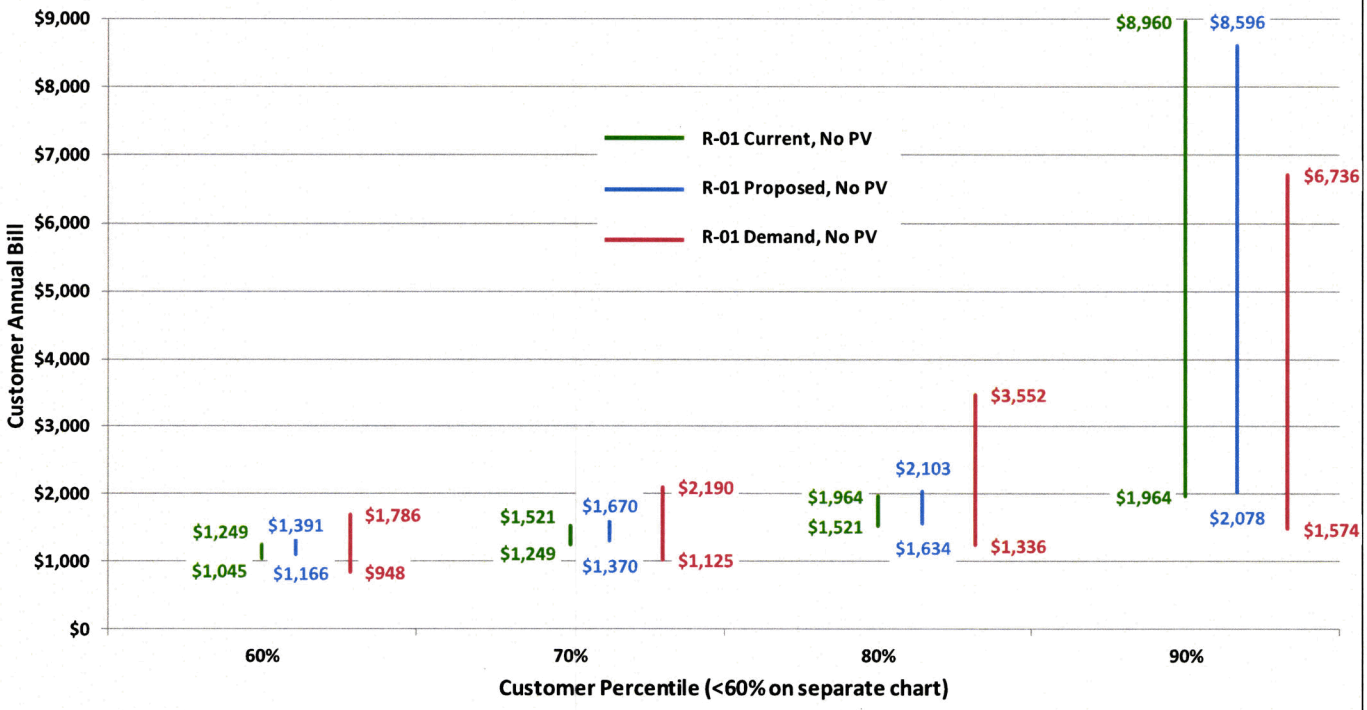
Conclusions:

- R-01 Demand bills are highly sporadic and unpredictable amongst all residential customers
- There is a predictable customer impact when remaining on a two-part rate plan
- There is little variation within customers of similar usage when implementing the Company's proposed R-01 without demand
- Since the Company has proposed to double the R-01 fixed charges, low usage customers are severely affected under both the two-part and three-part rate plan
- Low usage customers (who typically have a lower load factor) are even more severely impacted on a three part rate plan
- Nearly all high usage customers would experience significant bill decreases on a three part rate plan

Bill Impact By Customer Size - Current R-01 to Proposed R-01 and R-01 Demand



Bill Impact Range By Customer Size - Current R-01 to Proposed R-01 and R-01 Demand



Q: Please explain the preceding graph and outline your conclusions.

A: **Explanation:** For each customer percentile (percentiles based on current R-01 annual bill), there are three lines. This chart was created using the actual customer data provided by the Company and unmodified.

The **green** line represents the range of bills under the **current R-01 rate plan, without DG**. For example, in the 30th percentile, the lowest bill is $541 and the highest bill is $700.

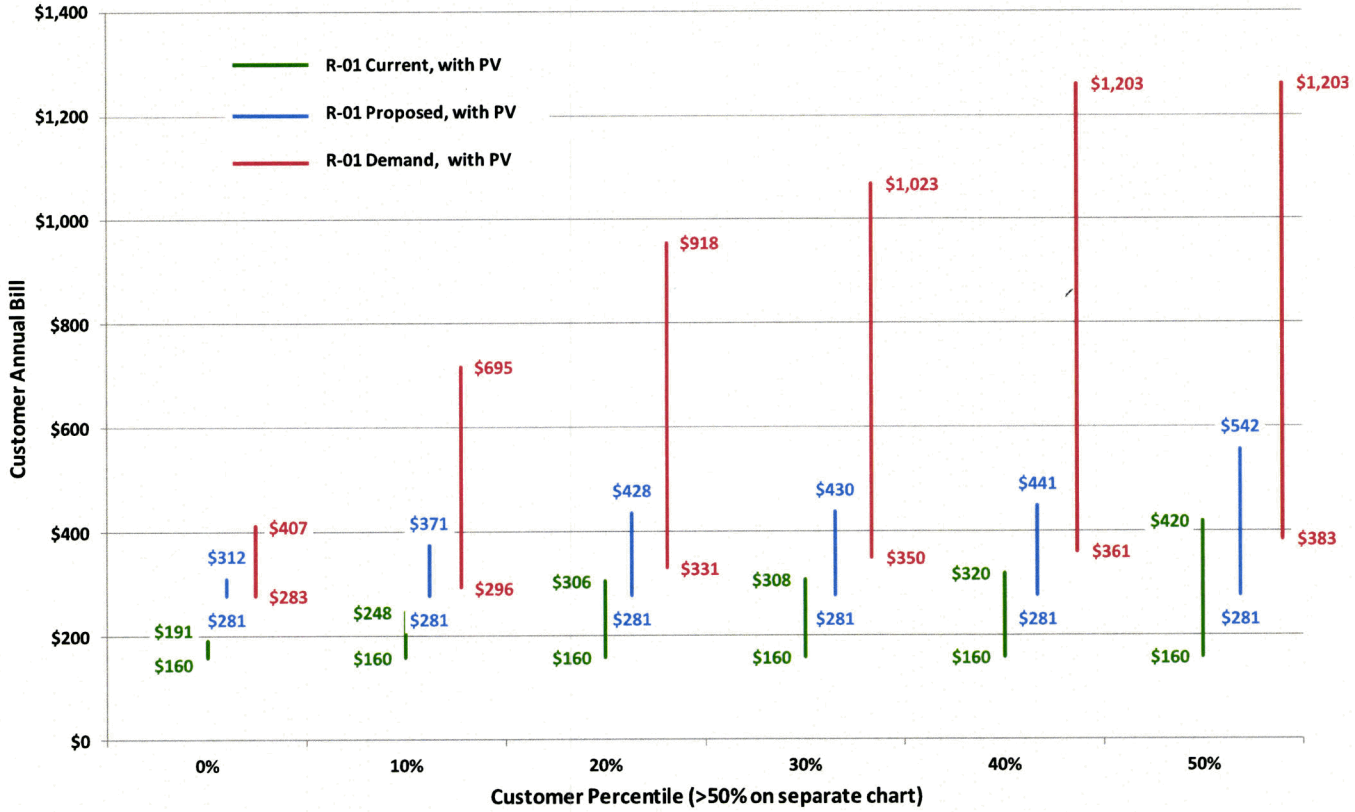
The **blue** line represents the range of bills under the **proposed R-01 rate plan, without DG**. For example, in the 30th percentile, the lowest bill would be $656 and the highest bill would be $829.

The **red** line represents the range of bills under the **proposed R-01Demand rate plan, without DG**. For example, in the 30th percentile, the lowest bill would be $593 and the highest bill would be $1,316.

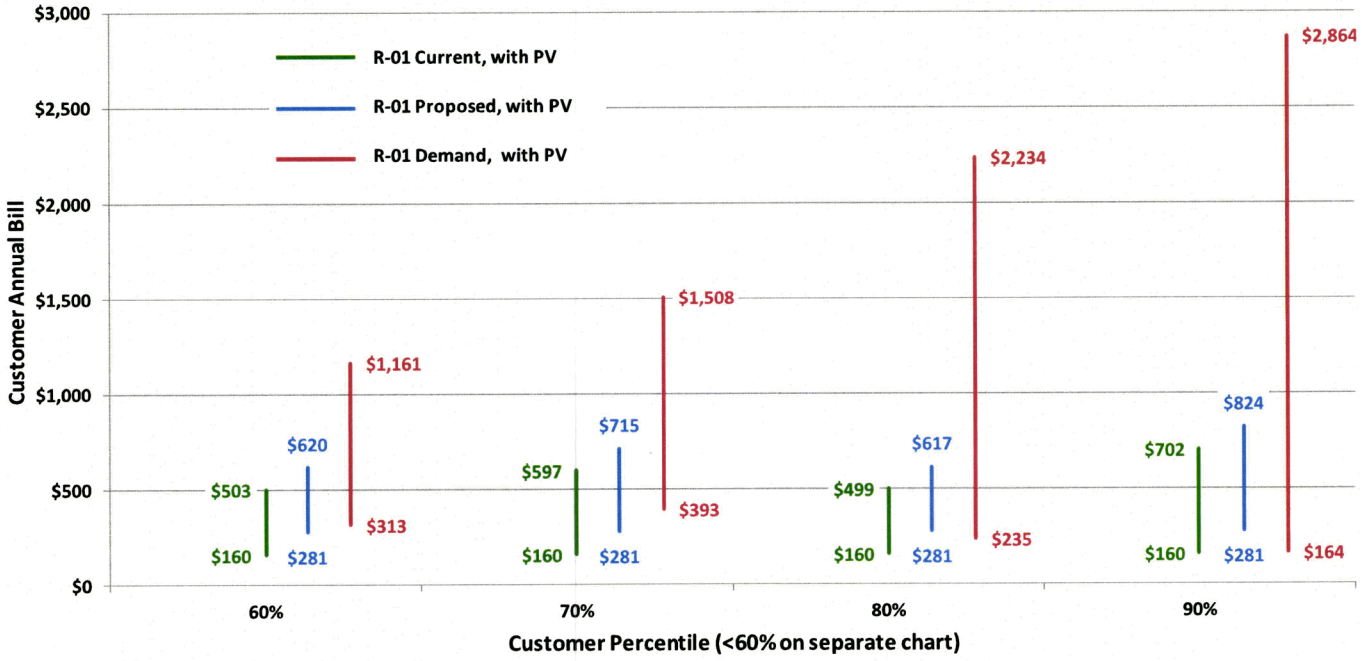
Conclusions:

- R-01 Demand bills are highly sporadic and unpredictable amongst all residential customers
- Low usage customers (who typically have a lower load factor) would experience extreme bill increases
- High usage customers would, on average, see bill reductions

Resulting Bill Range By Customer Size - Current R-01 to Proposed R-01 and R-01 Demand, With PV



Bill Impact Range By Customer Size - Current R-01 to Proposed R-01 and R-01 Demand, With PV



Q: **Please explain the preceding graph and outline your conclusions.**

A: **Explanation:** For each customer percentile (percentiles based on current R-01 annual bill), there are three lines. This chart was created using the actual customer data provided by the Company and unmodified.

The **green** line represents the range of bills, with a 100% offset solar project installed, under the **current R-01 rate plan with Net Metering**. For example, in the 30th percentile, the lowest bill is $160 and the highest bill is $308.

The **blue** line represents the range of bills, with a 100% offset solar project installed, under the **proposed R-01 rate plan with Net Metering**. For example, in the 30th percentile, the lowest bill would be $281 and the highest bill would be $430.

The **red** line represents the range of bills, with a 100% offset solar project installed, under the **proposed R-01 Demand rate plan with the RCR**. For example, in the 30th percentile, the lowest bill would be $350 and the highest bill would be $1,023.

Conclusions:

- The Company's testimony and analysis does not adequately address the extreme variation when instituting a three-part rate plan. This is especially troubling since the Company proposes to **force** DG customers onto this rate plan

- The Company's proposal to force DG customers onto a three part rate plan is untested, premature, discriminatory, volatile, and unstable

FINDING 2: THE COMPANY MUST RELEASE COMMERCIAL CUSTOMER 15 MINUTE INTERVAL DATA AND THE COMPANY HAS NOT ADEQUATELY DEMONSTRATED RATE PLAN IMPACTS TO COMMERCIAL CUSTOMERS, WITH OR WITHOUT DG

Q: Please summarize the purpose and conclusions of this section.

A: I will show the Company has not supplied adequate commercial data to perform a meaningful analysis of its wide ranging, aggressive, and unprecedented proposals. Using actual, unedited interval data from 13 Arizona schools, I will show the Company's proposal to institute mandatory MGS and LGS rate plans has severe, wide ranging consequences. I believe this analysis will be especially meaningful to Staff, given their denied request to the Company for impacts to actual commercial customers (Staff DR 20.08).

Q: Did the Company provide any 60 or 15 minute commercial load data for analysis?

A: Despite having 19,110 AMR meters installed for commercial customers at the start of the test year that log usage in 60-minute or 15-minute intervals (SOLON DR 2.10), the Company has not provided interval data for commercial customers of any size, despite requests from SOLON and Staff (SOLON DR 3.2, Staff DR 20.08).

Q: Does SOLON have access to any commercial load data for analysis?

A: Yes. Through its course of normal business operations, SOLON has acquired 12 months of hourly interval load data for 13 Arizona schools, and

kept this data unaltered for an unbiased analysis of rate impact. Total annual usage (kWh) for each school is listed below, and the complete interval data is available upon request.

School	Annual Usage
1	453,283
2	301,573
3	1,219,675
4	1,399,040
5	2,184,291
6	1,317,382
7	7,280,648
8	5,494,477
9	3,707,150
10	1,308,680
11	91,414
12	653,585
13	2,782,785

Q: What analysis did you perform with the schools' interval data?

A: First, I quantified their monthly usage and demand, their current pre-tax utility bill, what rate plan the Company would force them into based on the Company's proposal, their pre-tax utility bill under the Company's proposals, and their billing demand with any Company proposed minimum demands and ratchets applied.

Second, I analyzed which rate plan would be most economical for the school under the Company's proposal, assuming the Company relinquished control over all rate plan choices and allowed the customer to choose. I then quantified the customer's savings given their ability to select a rate plan.

Third, I analyzed how the Company's proposed ratchets impact customer billed demand. I quantify, by month, how the Company would overbill each school and the associated cost impact.

Q: What were your findings on the first two items?

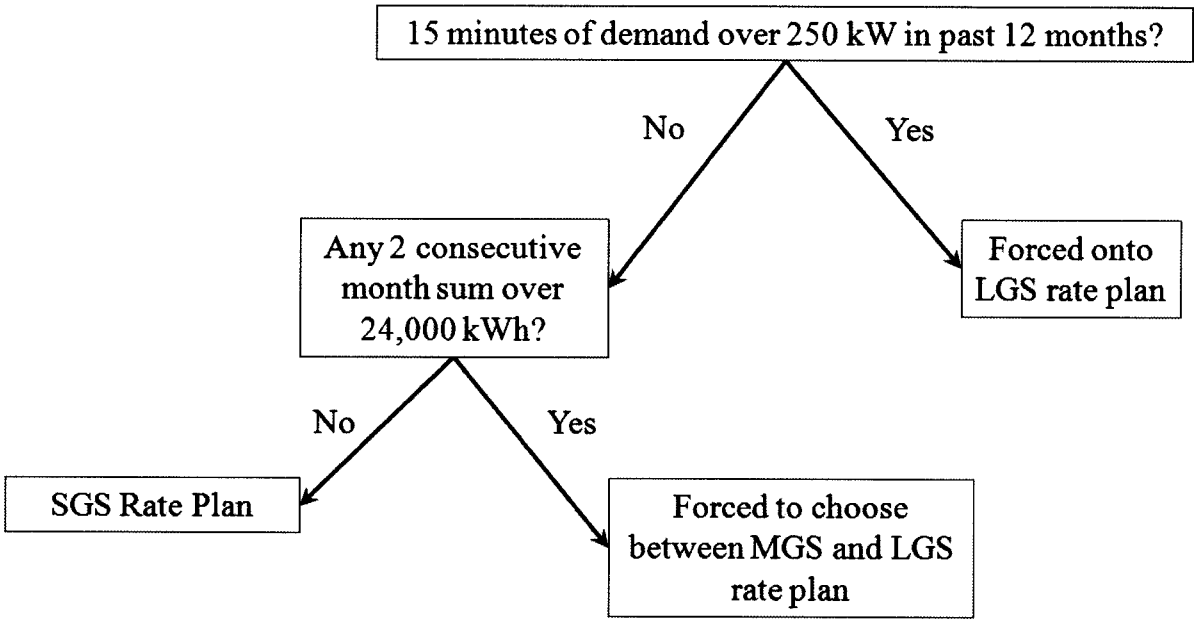
A: I will address the third item, ratchets, in the next section of my testimony. With regards to the first two items, under the Company's proposals, the schools would see volatile, wide ranging bill increases. Below is a summary of the schools' rate plan, current pre-tax utility bill, and pre-tax utility bill under the Company's proposed rate plans.

School	Current Rate Plan *Customer Chooses Rate Plan*	New Rate Plan *Company Chooses Rate Plan*	Current Utility Bill *Customer Chooses Rate Plan*	New Utility Bill *Company Chooses Rate Plan*	Bill Increase *($)*	Bill Increase *(%)*
1	GS-10	MGS	$61,033	$67,464	$6,431	10.5%
2	GS-10	MGS	$41,386	$49,208	$7,822	18.9%
3	GS-10	LGS	$162,533	$187,862	$25,328	15.6%
4	GS-10	LGS	$194,087	$238,992	$44,905	23.1%
5	LGS	LGS	$250,353	$268,739	$18,386	7.3%
6	LGS	LGS	$157,793	$170,262	$12,469	7.9%
7	LGS	LGS	$707,895	$752,687	$44,792	6.3%
8	LGS	LGS	$588,049	$629,580	$41,531	7.1%
9	LGS	LGS	$422,178	$453,652	$31,474	7.5%
10	LGS	LGS	$172,826	$187,593	$14,767	8.5%
11	GS-10	GS-10	$13,089	$13,634	$545	4.2%
12	GS-10	MGS	$87,878	$89,405	$1,528	1.7%
13	LGS	LGS	$277,956	$295,592	$17,636	6.3%

Conclusions: With only a sample set of 13 schools, the pre-tax cost increases range from 1.7% to 23.1%. This is largely due to the Company's proposals to force customers into specific rate plans.

Q: How does the Company propose to choose rate plans for commercial customers?

A: The Company proposes commercial rate plans be selected under the following logic:



Q: How does the Company currently choose rate plans for commercial customers?

A: The customer currently has the freedom to choose their rate plan.

Q: Are there any challenges for a commercial customer with the proposed mandatory rate plans?

A: Yes. To provide a brief background, the Company records demand in 15 minute intervals. The highest single 15 minute interval is identified per billing cycle is recorded (regardless of the other 2,879 fifteen minute

intervals in a month) and the Company bills the commercial customer based on that single 15 minute interval. This value is also used to determine ratchets and what rate plan the Company will force upon the commercial customer. Specifically with regards to the MGS and LGS rate plans, the Company has proposed the following:

"A new cap of 250 kW will be established such that any customer meeting or exceeding the cap for a billing month will automatically be moved, in the subsequent month, to the LGS rate class. The customer must remain there for at least 12 months without exceeding the 250 kW demand to qualify to move back to MGS." (Craig Jones testimony, page 47, lines 8-12)

This results in extreme disparity and unfairness. If a commercial customer, for 15 minutes of a year (0.00285% of a year), experiences a peak load of greater than 250kW, they will be automatically, without consent, forced onto the LGS rate plan for a minimum of 12 months. In order to be transitioned back to the MGS rate plan, the customer must then maintain a load of less than 250kW for 12 straight months (100% of a year).

Q: Does this proposal have financial impacts to a commercial customer?

A: Yes. See below for minimum annual charges for the MGS and LGS rate plan. A customer forced onto an LGS rate plan immediately experiences an annual fixed cost increase over $52,000 regardless of usage.

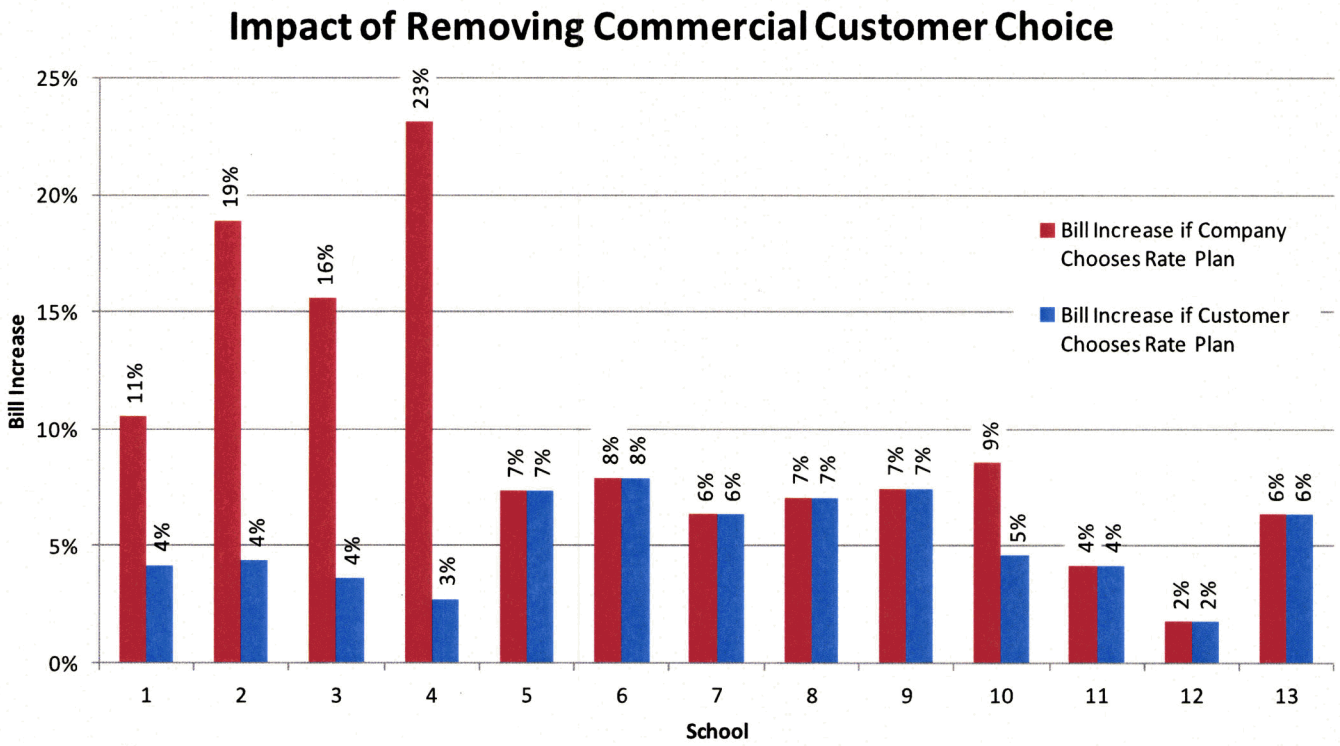
	Monthly Fixed Cost	Minimum Demand (kW)	Average Demand Charge	Minimum Demand Charge	Total Minimum Monthly Bill	Total Minimum Annual Bill
MGS	$40	20	$6.00	$120	$160	$1,920
LGS	$1,000	200	$17.50	$3,500	$4,500	$54,000

Q: What would be the billing impact if the Company allowed each school to choose their rate plan?

A: The Company's automatic selection of a rate plan does not always result in a positive outcome for the customer. With only a sample set of 13 schools, there were 5 instances where the automatic selection was not the best outcome for the school. These are highlighted in orange on the following table.

School	New Rate Plan *Company Chooses Rate Plan*	New Rate Plan *School Chooses Rate Plan*	New Utility Bill *Company Chooses Rate Plan*	New Utility Bill *School Chooses Rate Plan*	Bill Savings by Allowing Customer Choice ($)	Bill Savings by Allowing Customer Choice (%)
1	MGS	GS-10	$67,464	$63,581	$3,883	5.8%
2	MGS	GS-10	$49,208	$43,201	$6,007	12.2%
3	LGS	GS-10	$187,862	$168,396	$19,466	10.4%
4	LGS	GS-10	$238,992	$199,382	$39,610	16.6%
5	LGS	LGS	$268,739	$268,739	$0	0.0%
6	LGS	LGS	$170,262	$170,262	$0	0.0%
7	LGS	LGS	$752,687	$752,687	$0	0.0%
8	LGS	LGS	$629,580	$629,580	$0	0.0%
9	LGS	LGS	$453,652	$453,652	$0	0.0%
10	LGS	GS-10	$187,593	$180,769	$6,824	3.6%
11	GS-10	GS-10	$13,634	$13,634	$0	0.0%
12	MGS	MGS	$89,405	$89,405	$0	0.0%
13	LGS	LGS	$295,592	$295,592	$0	0.0%

Additionally, the graph below outlines a similar message.



FINDING 3: AN ANNUAL RATCHET PUTS INSURMOUNTABLE PRESSURE ON COMMERCIAL CUSTOMERS TO STRICTLY MONITOR DEMAND, AND RATCHETS DIS-INCENTIVIZE ALL DG, EE, AND STORAGE TECHNOLOGIES

Q: Please summarize the purpose and conclusions of this section.

A: I will show the Company has not supplied adequate commercial data to perform a meaningful analysis of its wide ranging, aggressive, and unprecedented proposals. Using actual, unedited interval data from 13 Arizona schools, I will show the Company's proposal to institute a 75% ratchet on MGS customers will result in rampant overbilling the customer is nearly powerless to avoid.

Q: What is a ratchet?

A: A ratchet is a minimum billing demand based on historical demand outside of the current billing period. For example, if a customer required 100kW of demand 11 months ago, but only 30kW of demand in the current billing period, a ratchet would increase the billing period demand of 30kW to a billed value more in line with 100kW.

Ratchets typically vary in two ways:

- How far back the utility can look into historical demand
- What percentage of peak demand in the look back period is applied to the current billing period

Q: What ratchet is the Company proposing to implement in the proposed MGS rate plan?

A: The Company is proposing a look back period of 12 months and minimum of 75% of peak historical demand.

So, in the example in the previous question, the customer's current billing period demand would be adjusted from 30kW to 75kW and billed for 75kW.

Q: How would the ratchet impact the 13 schools?

A: I've analyzed billed demand against actual demand assuming the following items:

- The Company's proposed rate plans are accepted
- The Company's proposed thresholds are accepted and the school is forced into a rate plan
- The Company's proposed 75% ratchet with a 12 month look back is accepted

Following are two tables that illustrate actual vs. billed demand, per school and by month. Values in orange indicate the school would be overbilled against their actual demand.

Effects of a Ratchet - Actual vs. Billed Demand

School	Jan		Feb		Mar		Apr		May		Jun	
	Actual	Billed	Actual	Billed	Actual	Billed	Actual	Billed	Actual	Billed	Actual	Billed
1	151	151	192	192	167	167	149	149	131	144	111	144
2	195	195	150	150	100	146	79	146	54	146	65	146
3	564	564	458	458	325	423	302	423	189	423	185	423
4	393	560	398	560	381	560	425	560	428	560	527	560
5	660	660	583	583	445	495	401	495	388	495	372	495
6	412	412	388	388	293	309	257	309	190	309	176	309
7	1,379	1,379	1,223	1,223	1,206	1,206	1,369	1,369	1,276	1,276	1,333	1,333
8	1,284	1,284	1,023	1,197	1,261	1,261	789	1,197	1,142	1,197	1,219	1,219
9	572	873	651	873	689	873	761	873	896	896	967	967
10	518	518	413	413	301	389	276	389	241	389	199	389
11*	22	0	19	0	22	0	26	0	23	0	21	0
12	149	149	140	140	126	126	115	115	101	112	90	112

**No demand charges because school stays on GS-10 rate plan*

13

Effects of a Ratchet - Actual vs. Billed Demand

School	Jul		Aug		Sep		Oct		Nov		Dec	
	Actual	Billed	Actual	Billed	Actual	Billed	Actual	Billed	Actual	Billed	Actual	Billed
1	110	144	101	144	121	144	121	144	89	144	105	144
2	61	146	89	146	63	146	65	146	125	146	142	146
3	172	423	195	423	198	423	240	423	365	423	434	434
4	699	699	747	747	742	742	490	560	369	560	280	560
5	367	495	407	495	398	495	468	495	532	532	532	532
6	154	309	198	309	195	309	272	309	322	322	352	352
7	1,353	1,353	1,489	1,489	1,552	1,552	1,468	1,468	1,378	1,378	1,342	1,342
8	1,271	1,271	1,414	1,414	1,596	1,596	1,008	1,197	969	1,197	798	1,197
9	1,133	1,133	1,051	1,051	1,164	1,164	785	873	821	873	643	873
10	223	389	294	389	291	389	238	389	338	389	482	482
11*	21	0	32	0	32	0	23	0	23	0	18	0
12	101	112	115	115	119	119	112	112	133	133	143	143

**No demand charges because school stays on GS-10 rate plan*

26

Q: **What is the monetary impact of this frequent overbilling?**

A: Please see the below table. For only a sample set of 13 schools, the schools will be overbilled by $148,885 in the first year alone, which is highlighted in orange.

Effects of a Ratchet - Overbilling by Month ($)

School	Total	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	148,885	8,195	9,781	10,995	18,458	14,723	13,492	13,120	9,819	10,073	13,549	10,535	16,144
1	1,626	0	0	0	0	96	236	240	301	160	119	275	198
2	3,888	0	0	231	337	646	566	593	399	583	407	104	22
3	28,563	0	0	1,704	2,112	4,086	4,161	4,382	3,978	3,930	3,199	1,011	0
4	23,598	2,924	2,838	3,142	2,361	2,306	574	0	0	0	1,219	3,337	4,898
5	12,498	0	0	877	1,649	1,880	2,151	2,236	1,546	1,690	469	0	0
6	12,855	0	0	275	899	2,075	2,332	2,701	1,930	1,996	646	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0
8	25,498	0	3,058	0	7,153	974	0	0	0	0	3,318	3,998	6,997
9	20,844	5,272	3,886	3,230	1,972	0	0	0	0	0	1,542	914	4,028
10	19,219	0	0	1,535	1,976	2,584	3,324	2,896	1,664	1,714	2,631	895	0
11*	0	0	0	0	0	0	0	0	0	0	0	0	0
12	297	0	0	0	0	76	148	72	0	0	0	0	0

**No demand charges because school stays on GS-10 rate plan*

Q: **How can a customer avoid being overbilled with a ratchet?**

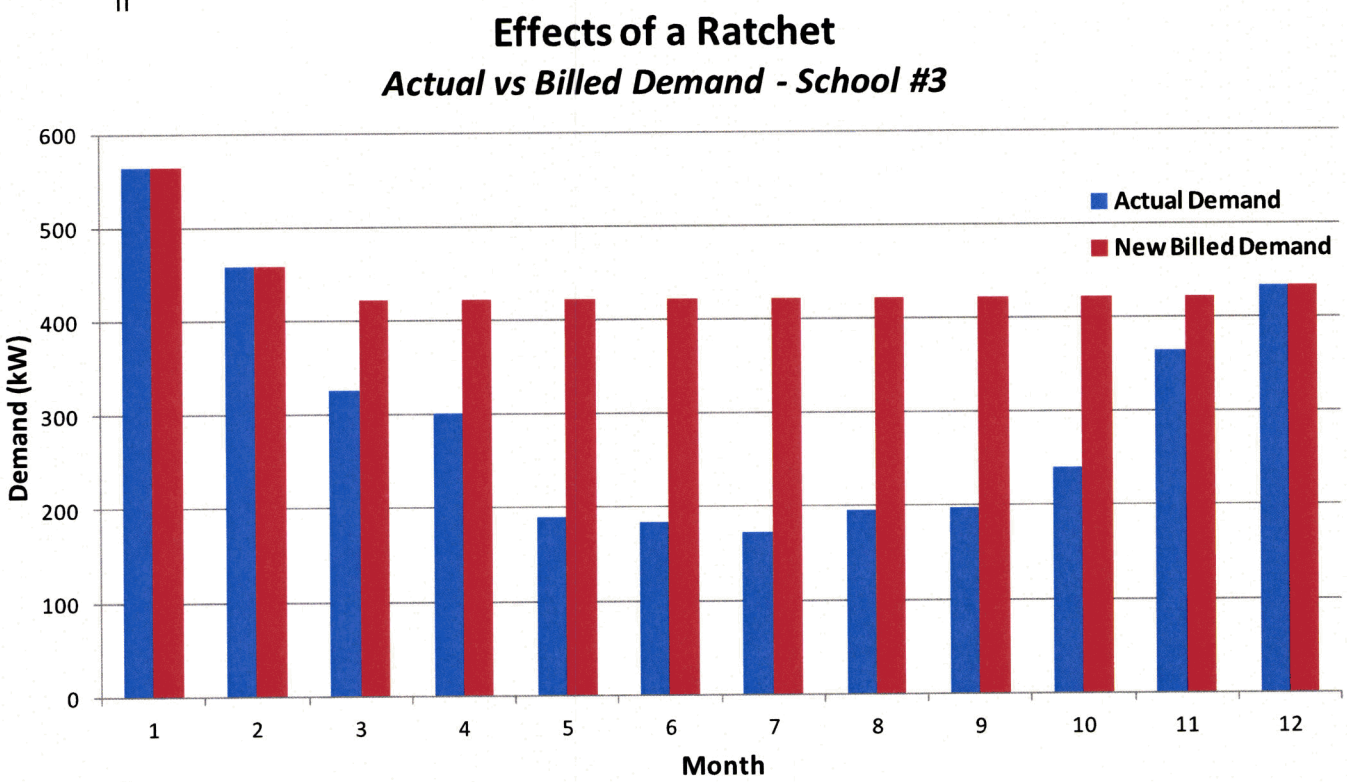
A: As previously discussed in Part 2 of this section, this is a point I cannot stress enough. A commercial customer could implement state of the art demand controls; install storage; install DG solar; hire an energy manager; educate their entire staff on energy use, demand, minimum demand charges, load factors, and ratchets; or implement any other technology the Company has suggested they promote, without impacting a ratchet. All it

takes is 15 minutes of imperfect energy management and the customer's minimum demand is set for the next 12 months, regardless of any future actions to mitigate the minimum demand set by the ratchet. Implementing this policy on current GS-10 customers who have never been billed for demand as long as they have been rooted in Tucson is irresponsible, damaging to economic development, and places undue stress on thousands of businesses.

Q: Were there any other findings in your analysis?

A: Yes. As shown in the previous tables most of the schools are regularly affected by the ratchet in the summer months, which makes sense given schools are usually on break for summer. Following is a chart depicting actual and billed demand for school #3 in our data set.

Explanation: The difference between the blue column and the red column represent overbilling due to the Company's proposed 75% ratchet. Billed demand (red column) is fixed from March to November due to January's peak demand.



Conclusion: This chart represents a prime example why the Company should be required to supply interval data for commercial customers for further analysis. The school would set their annual ratchet with an abnormally high January peak. Even though the school is on summer break, they are still billed high demand charges throughout the summer months when, presumably, the Company is experiencing peak demand and generation requirements. However, the school is not contributing to the Company's increased demand and generation requirements during these months.

FINDING 4: LOW USAGE BILLS (<400KWH) ARE RARELY DUE TO DG, SEASONAL HOMES, OR VACANCIES

Q: Please summarize the purpose and conclusions of this section.

A: I will challenge and debunk the Company's assertions that vacant homes, seasonal customers, and DG customers represent the vast majority of customers that do not pay their equitable share of fixed costs. I will show these three customer classes represent less than 5% of these customers.

Q: What statements are made by the Company with regards to low usage bills?

A: The Company makes the following statement "Nearly one out of every three residential (Residential R-01) bills issued by TEP during the test year - 1,308,714 to be precise - reflected usage of 400kWh or less. Because even a studio apartment with basic appliances and moderate usage would likely consume almost 400 kWh per month, these bills probably were generated by vacant homes, seasonal customers and DG customers. TEP recovered only $10 to $33 in fixed costs per month from these issued bills - a fraction of their equitable share of the fixed costs the Company incurs to provide service on their behalf." (Dukes 12:15)

Q: Did the Company offer any data or analysis to support this claim?

A: In response to a Vote Solar discovery request, the Company states: "Of the 1,308,714 residential R-01 bills for 400 kWh or less, 54,771 were from net metering customers." (Vote Solar DR 2.10)

It is simple to conclude that, of the three alleged perpetrators (vacant, seasonal, and DG customers) for bills 400kWh and less, DG represents 4.19%.

The Company did not offer any further data or analysis to support the claims of vacant homes or seasonal homes. In fact, the Company states "The Company does not currently track seasonal versus year round customers" (RUCO DR 7.11), and "The Company does not track vacant homes." (RUCO DR 7.11)

Q: Using the 17,296 hourly residential load profiles provided by the Company, how many months were under 400kWh?

A: 49,830 of the 207,552 months, or 24%.

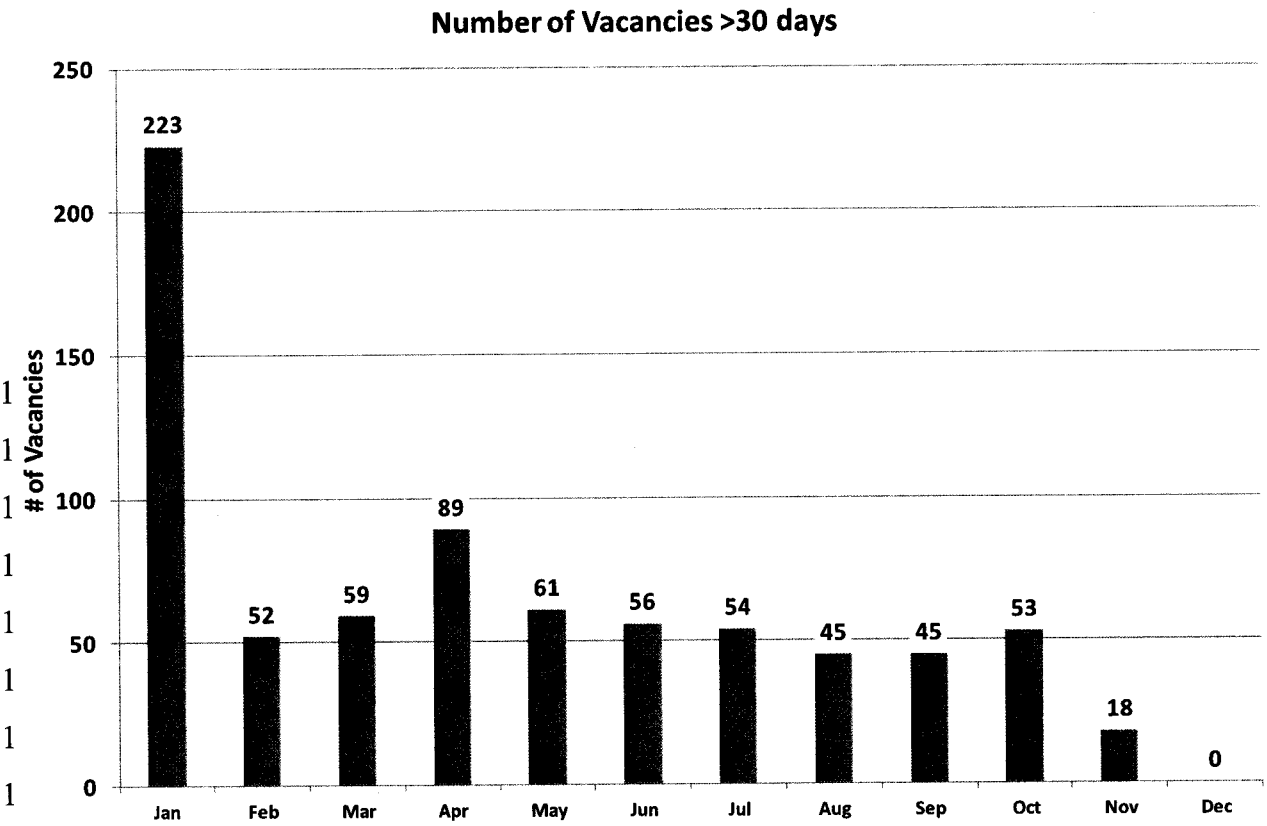
Q: How many of these 49,830 months under 400kWh were due to DG?

A: The Company admits that "None of the customers in the samples were identified as TEP NEM customers." (VS DR 2.44). Zero of the 49,830 months under 400kWh can be attributed to DG.

Q: Do you have any analysis to provide with regards to vacant homes?

A: Yes. Within the hourly test year data, the Company recorded a zero if there was no usage recorded but an AMR meter had been installed, and a blank if the AMR meter had not yet been installed. I searched for the number of unique periods with a zero value for greater than 30 consecutive days (720 hours) and logged the number of these periods which began in each month.

There were a total of 755 vacancies of 30 days or more amongst the 49,830 months of 400kWh or less, equating to 0.36%.

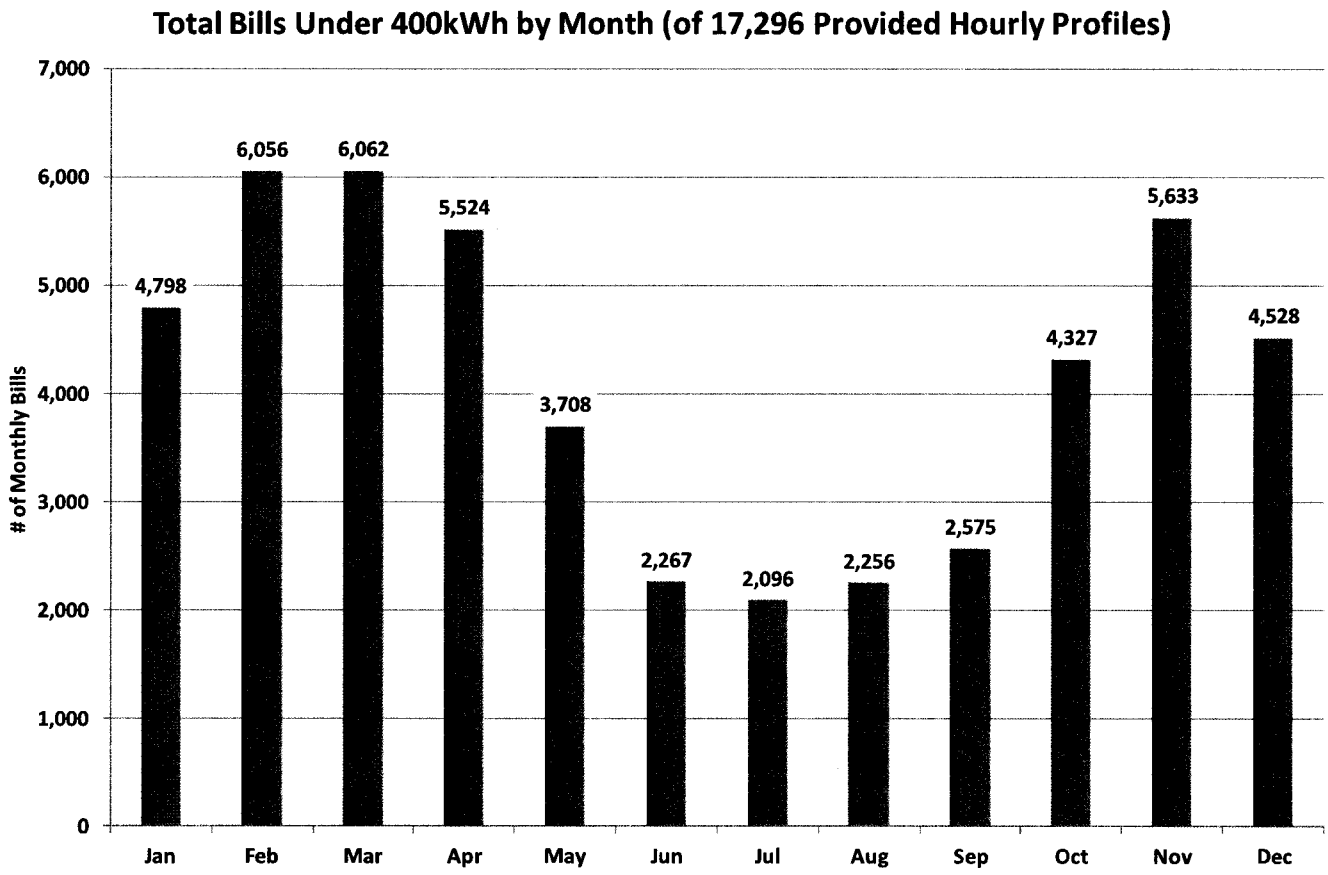


Q: Do you have any analysis to provide with regards to seasonal homes?

A: Yes. One can reasonably infer or conclude that, when the Company states "these bills probably were generated by…seasonal customers" (Vote Solar DR 2.10), they are referring to customers leaving their service territory in the summer months and returning for the winter months.

So far I've shown that, of the 49,830 months with 400kWh or less, zero were due to DG (by the Company's own admission) and approximately 755

were due to vacancies (by my previous analysis). Therefore, should the Company's statement be true, one would expect a substantial number of bills less than 400kWh during the summer months, with nearly zero bills less than 400kWh in the winter months. However, when charting the number of bills less than 400kWh by month, I find the exact opposite to be true. The following chart shows a steep decline in the number of bills less than 400kWh in the summer months.



Q: What conclusions do you draw from this analysis?

A: The Company's entire basis for their aggressive, wide ranging, and unprecedented proposals rests on cost shift due to DG, seasonal homes, and vacant homes. It is clear the Company has not adequately evaluated this issue, and their claim that "these bills probably were generated by vacant homes, seasonal customers and DG customers" is false.

FINDING 5: THE COMPANY'S PROPOSALS WILL ELIMINATE THE SOUTHERN ARIZONA DG SOLAR MARKET

Q: Please summarize the purpose and conclusions of this section.

A: I will describe how myself and our prospective DG customers evaluate the economics of a DG investment and how those economics would be affected by the Company's proposals. The data will show DG solar in the Company's service territory will be immediately and sharply impacted, becoming instantly non-competitive.

Q: How do most DG customers procure solar?

A: In my experience, almost all DG solar customers procure solar via a Solar Service Agreement (SSA). An SSA allows the customer to purchase the solar energy over time at a fixed or escalating rate in lieu of purchasing the equipment outright. There are certainly customers who opt to purchase the equipment outright and maintain the system themselves, but, even though I do not have hard data to support how all customers procure solar, I can confidently state the equipment purchase option is rarely used.

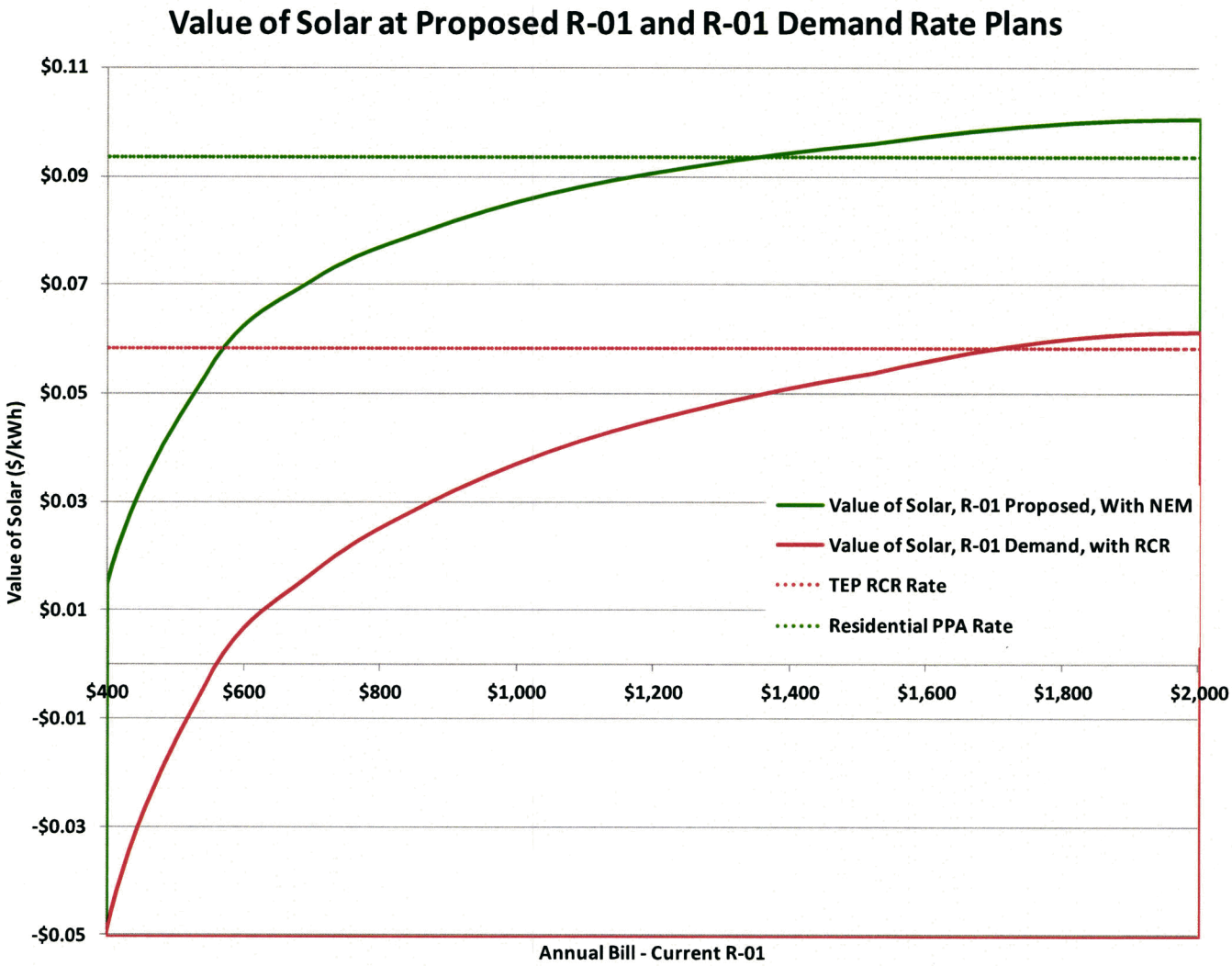
Q: How does a typical prospective customer evaluate a DG solar investment?

A: A typical customer evaluates two major items:

- Stability of utility programs; and
- SSA rate versus utility average avoided cost (or, the "value of solar", see Exhibit C for a definition)

Q: How do the Company's proposals impact a customer's buying criteria?

A: First, any retroactive rate making, including the Company's proposals to eliminate net metering, open up a dangerous door to complete instability of all the Company's ACC approved policies, DG or otherwise. Secondly, the uncertainty heightens when the Company forces a residence or business onto a rate plan they don't understand, do not have the tools nor technical ability to evaluate, and cannot rely on the Company to provide adequate data to evaluate. Lastly, I will show on the following pages the resulting DG solar avoided cost for residences and business under the Company's proposal is routinely lower than the Company's RCR rate of $0.0584/kWh, the rate the Company can procure utility scale solar.



Explanation: The solid green curve represents the value of solar to the end residential customer at various customer usage levels under the proposed R-01 rate plan with current Net Metering rules. For example, for a customer with a current annual bill of $1,200, the average value of a solar kWh to this residential customer is approximately $0.09/kWh.

The solid red curve represents the value of solar to the end residential customer at various customer usage levels under the proposed R-01 Demand rate plan with the RCR applied. For example, for a customer with a current annual bill of $1,200, the average value of a solar kWh to this residential customer is approximately $0.045/kWh.

The dashed red line represents the Company's proposed RCR of $0.0584/kWh (the rate the Company can currently procure utility scale solar). Any curve above the dashed red line means, if the residential customer were to procure solar at the RCR rate, the customer would save money on their solar investment. Any curve below the dashed red line means, if the residential customer were to procure solar at the RCR rate, the customer would still lose money on their solar investment.

The dashed green line represents a typical residential solar SSA rate of $0.0935/kWh. Derivation of this value is explained in the next question. Any curve above the dashed green line means, if the residential customer were to procure solar at the typical residential solar SSA rate, the customer would save money on their solar investment.

Conclusions:

Under the Company's proposal of instituting an RCR, mandatory three-part rate structures, and doubling monthly fixed costs:

- Residential solar would instantly become unfeasible for all customers

- The majority of customers would need to procure solar for LESS THAN the Company's proposed RCR, which is the rate the Company can procure utility scale solar
- Dallas Dukes' and Carmine Tilghman's statement of "Under this proposal, DG customers would still see significant savings on their electric bills" is ignores all other economics of a solar project

Q: How did you arrive at an average residential SSA rate?

A: Certainly there is significant data in the industry to estimate an average SSA rate in Arizona. However, to avoid debates over sources, types of systems, and any other assumptions in the data set, I opted to take the Company's stated installation cost of $2.19/W-dc (Staff DR 25.2) and generate an SSA rate using standard industry assumptions and other assumptions in line with the Company's testimony. These assumptions are listed in Exhibit C. The installation cost of $2.19/W-dc is highly conservative, because a typical homeowner cannot procure residential solar on a level playing field with the Company, due to the following items:

- Company's volume procurement of hundreds of residential solar projects at once
- Company affords themselves looser and cheaper interconnection rules
- Company has substantially lower customer acquisition costs
- Company does not include installation profit margin

Q: Did you perform a similar analysis for the 13 schools you provided?

A: Yes. Please see the below tables.

School	Current Rate Plan	Current Utility Bill	Utility Bill with DG and NEM	Value of Solar	Utility Bill with DG and RCR	Value of Solar	Value of Solar Reduction
1	GS-10	$61,033	$3,123	$0.128	$25,262	$0.079	-38%
2	GS-10	$41,386	$3,533	$0.126	$20,785	$0.068	-46%
3	GS-10	$162,533	$13,841	$0.122	$106,657	$0.046	-62%
4	GS-10	$194,087	$442	$0.138	$141,488	$0.038	-73%
5	LGS	$250,353	$110,222	$0.064	$123,147	$0.058	-9%
6	LGS	$157,793	$73,864	$0.064	$80,748	$0.058	-8%
7	LGS	$707,895	$252,950	$0.062	$287,234	$0.058	-8%
8	LGS	$588,049	$229,099	$0.065	$265,725	$0.059	-10%
9	LGS	$422,178	$184,106	$0.064	$213,476	$0.056	-12%
10	LGS	$172,826	$87,380	$0.065	$97,525	$0.058	-12%
11	GS-10	$13,089	$467	$0.138	$5,863	$0.079	-43%
12	GS-10	$87,878	$6,747	$0.124	$32,516	$0.085	-32%
13	LGS	$277,956	$101,609	$0.063	$114,156	$0.059	-7%

Explanation: The "Value of Solar with NEM" column represents the school's average avoided cost per kWh for a DG solar array that generates 100% of the school's annual usage under the Company's current rate structures and Net Metering policies. The "Value of Solar with RCR" column represents the school's average avoided cost per kWh for the DG solar array that generates 100% of the school's annual usage under the Company's proposed rate structures and RCR policies. The final column represents the net impact, per school, to the value of solar under the Company's proposals.

Conclusions:

- With just a sample set of 13 schools, the Company's proposals impact the value of solar between 7% and 73%
- The Company's proposals ignore the principles of gradualism

School	New Rate Plan	Current Utility Bill	Utility Bill with DG and RCR	Value of Solar	RCR Rate
1	MGS	$61,033	$25,262	$0.0789	$0.0584
2	MGS	$41,386	$20,785	$0.0683	$0.0584
3	LGS	$162,533	$106,657	$0.0458	$0.0584
4	LGS	$194,087	$141,488	$0.0376	$0.0584
5	LGS	$250,353	$123,147	$0.0582	$0.0584
6	LGS	$157,793	$80,748	$0.0585	$0.0584
7	LGS	$707,895	$287,234	$0.0578	$0.0584
8	LGS	$588,049	$265,725	$0.0587	$0.0584
9	LGS	$422,178	$213,476	$0.0563	$0.0584
10	LGS	$172,826	$97,525	$0.0575	$0.0584
11	GS-10	$13,089	$5,863	$0.0791	$0.0584
12	MGS	$87,878	$32,516	$0.0847	$0.0584
13	LGS	$277,956	$114,156	$0.0589	$0.0584

Explanation: An extension of the previous table, this compares the value of solar under the Company's proposals to the Company's proposed RCR rate.

Conclusions:

- Under the Company's proposals, 6 of the 13 schools would need to procure solar for LESS THAN the RCR, which is the rate the Company can procure utility scale solar

Q: Do you have any closing statements?

A: Yes. My testimony, through actual customer data and responsible analysis, clearly demonstrates the Company's wide ranging, aggressive, and unprecedented proposals are premature, not sufficiently researched, and would have extreme and unpredictable financial impacts on its customers. My testimony details the dangers of retroactive rate making and the chilling precedent it would set. My testimony challenges major portions of the Company's arguments that vacant, seasonal, and DG customers are the primary cause of low usage bills causing undue cost shift. Lastly, I show how the Company's proposals will eliminate the competitive Southern Arizona DG market and violate the second goal of the ACC's five-year strategic plan (ACC strategic plan 2014-2019).

SOLON's continued local job creation is dependent on a regulatory environment that promotes renewable energy and a regulated utility that sends consistent signals to its consumers.

SOLON is not intervening in this rate case to blindly disagree with every topic the Company proposes. In fact, this is the first time SOLON has ever intervened in a rate case. In 2007, when SOLON opted to establish their headquarters in Tucson, Arizona, it saw a vibrant, curious, accepting energy community eager to adopt competing resources to bolster Tucson's economy. SOLON has worked in concert with the Company on solar and storage projects aimed to improve the industry's understanding of renewables. However, when the Company proposes such extreme measures, they leave prudent local businesses no choice but to intervene.

We hope our testimony sparks a dialogue around transparency, real world analysis, fair competition, respect, simplicity, and gradualism. I urge the Commission, Staff, the Company, and all other intervenors to not lose sight of these common sense principles that, ultimately, will positively benefit our community.

Q: Does this conclude your testimony?

A: Yes. Thank you for reading.

EXHIBIT A

EXHIBIT A

Proposed Revisions to Address Issues 1-5

Revision 1

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color: [redacted]

Location(s): J52:J54; J58:J8817

Description: Remove formulas that artificially alter solar production to closely align to monthly utility usage. The Company's model took accurate solar production (cells G58:G8817 or H58:H8817) and substantially modified it. On the following pages are screenshots from the Company's Excel model (unaltered) that help illustrate how the Company's final solar production is unrealistic and false.

Screenshot location: Tab Load_PV XS

Through extensive modification, TEP's final solar profile is physically impossible

Load/PV System Summary:

Small Customer Monthly kWh	200	From "R-01 Demand" tab
Annual Customer Energy (kWh)	2,400	
Annual PV Production-South (kWh)	2,400	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	2,030	
System Size	1.33	kW-DC
Initial System Cost	$ 2,333.29	

1

	Day Count	365	31	28	31	30	31	30	31
			1	2	3	4	5	6	7
1	Description	Annual	January	February	March	April	May	June	July
2	Energy Use (kWh)	2,401	203	165	200	197	229	437	204
3	Total Peak Demand (kW)	2.74	2.02	1.89	2.16	2.07	2.15	2.74	1.27
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	2.74	2.02	1.89	2.16	2.07	2.08	2.74	1.20
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	10.0%	13.5%	13.0%	12.5%	13.2%	14.3%	22.2%	21.6%
8									
9	Net Hourly Energy Delivered (kWh)	2,561	165	184	251	285	306	292	202
10	Net Hourly Energy Received (kBh)	2,561	217	226	242	244	243	247	160
11									
12	Total PV Output (kWh)	2,400	206	167	201	199	231	438	203
13	PV Output (max kW)	2.0	1.3	1.2	1.1	0.9	1.1	2.0	0.9
14	Capacity Factor	13.4%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%
15									
16	Net-Metering Rollover	67	-	3	6	7	9	11	11
17	Billing kWh	2	-	-	-	-	-	-	-
18									
19									

2

1. 1.33kW-DC represents the theoretical maximum output of the solar panels, in direct current before converting to alternating current, which carries a conversion efficiency of 60-90%.
2. 2.0kW-AC represents the maximum output of the 1.33kW-DC system after TEP's modifications have been applied. **It is physically impossible for a 1.33kW-DC system to output 2.0kW-AC.**

Screenshot location: Tab Load_PV SM

Through extensive modification, TEP's final solar profile is physically impossible

Load/PV System Summary:		
Small Customer Monthly kWh	500	From "R-01 Demand" tab
Annual Customer Energy (kWh)	6,000	
Annual PV Production-South (kWh)	6,000	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	5,074	
System Size	3.33	kW-DC
Initial System Cost	$ 5,833.22	

	Day Count	365	31	28	31	30	31	30	31
			1	2	3	4	5	6	7
1	Description	Annual	January	February	March	April	May	June	July
2	Energy Use (kWh)	5,999	453	338	399	410	503	902	643
3	Total Peak Demand (kW)	4.82	3.88	3.54	3.77	3.64	4.14	4.82	3.39
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	4.51	3.88	3.54	3.77	3.64	3.99	4.51	3.15
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	14.2%	15.7%	14.2%	14.2%	15.7%	16.3%	26.0%	25.5%
8									
9	Net Hourly Energy Delivered (kWh)	4,291	274	300	398	449	478	454	367
10	Net Hourly Energy Received (kBh)	4,291	360	354	367	373	385	378	301
11									
12	Total PV Output (kWh)	6,000	454	341	401	411	510	916	633
13	PV Output (max kW)	4.3	2.9	2.4	2.2	1.9	2.4	4.3	3.0
14	Capacity Factor	16.0%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%
15									
16	Net-Metering Rollover	102	-	1	3	5	7	13	27
17	Billing kWh	0	-	-	-	-	-	-	-
18									
19									

1. 3.33kW-DC represents the theoretical maximum output of the solar panels, in direct current before converting to alternating current, which carries a conversion efficiency of 60-90%.
2. 4.3kW-AC represents the maximum output of the 3.33kW-DC system after TEP's modifications have been applied. **It is physically impossible for a 3.33kW-DC system to output 4.3kW-AC.**

Screenshot location: Tab Load_PV MED

Through extensive modification, TEP's final solar profile is physically impossible

Load/PV System Summary:

Medium Customer Monthly kWh	900	From "R-01 Demand" tab
Annual Customer Energy (kWh)	10,800	
Annual PV Production-South (kWh)	10,800	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	9,133	
System Size	6.00	kW-DC
Initial System Cost	$ 10,499.79	

	Description	Annual	January	February	March	April	May	June	July
	Day Count	365	31	28	31	30	31	30	31
			1	2	3	4	5	6	7
2	Energy Use (kWh)	10,801	795	600	668	678	829	1,392	1,286
3	Total Peak Demand (kW)	6.28	5.25	4.75	4.98	4.84	5.41	6.28	5.55
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	5.81	5.25	4.75	4.98	4.84	5.15	5.81	5.22
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	19.6%	20.4%	18.8%	18.0%	19.5%	20.6%	30.8%	31.2%
8									
9	Net Hourly Energy Delivered (kWh)	6,115	390	419	541	608	647	616	564
10	Net Hourly Energy Received (kBh)	6,116	487	503	508	502	521	518	482
11									
12	PV Output (kWh)	10,800	818	614	671	677	823	1,378	1,262
13	PV Output (max kW)	6.4	5.2	4.4	3.6	3.2	3.8	6.4	5.9
14	Capacity Factor	19.1%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%
15									
16	Net-Metering Rollover	203	-	23	37	40	40	33	19
17	Billing kWh	32	-	-	-	-	-	-	5
18									
19									

1. 6.0kW-DC represents the theoretical maximum output of the solar panels, in direct current before converting to alternating current, which carries a conversion efficiency of 60-90%.
2. 6.4kW-AC represents the maximum output of the 6.0kW-DC system after TEP's modifications have been applied. **<u>It is physically impossible for a 6.0kW-DC system to output 6.4kW-AC.</u>**

Screenshot location: Tab Load_PV LG

Through extensive modification, TEP's final solar profile is physically impossible

Load/PV System Summary:

Large Customer Monthly kWh	1,200	From "R-01 Demand" tab
Annual Customer Energy (kWh)	14,400	
Annual PV Production-South (kWh)	14,400	Note: Input for annual production in "Rate_PV Input" tab.
Annual PV Production-West (kWh)	12,178	
System Size	8.00	kW-DC (1)
Initial System Cost	$ 13,999.72	

	Description	Annual	January	February	March	April	May	June	July
	Day Count	365	31	28	31	30	31	30	31
			1	2	3	4	5	6	7
2	Energy Use (kWh)	14,400	1,016	753	849	875	1,073	1,762	1,819
3	Total Peak Demand (kW)	7.39	5.77	5.16	5.58	5.45	6.22	7.39	7.11
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	6.82	5.77	5.16	5.58	5.45	5.89	6.82	6.64
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	22.2%	23.7%	21.7%	20.4%	22.3%	23.2%	33.1%	34.4%
8									
9	Net Hourly Energy Delivered (kWh)	7,622	477	513	664	746	793	753	743
10	Net Hourly Energy Received (kBh)	7,621	612	634	640	638	627	603	603
11									
12	PV Output (kWh)	14,400	1,026	756	852	877	1,074	1,764	1,806
13	PV Output (max kW)	8.4	6.5	5.4	4.6	4.2	5.0	8.3 (2)	8.4
14	Capacity Factor	19.5%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%
15									
16	Net-Metering Rollover	111	-	10	13	16	18	19	20
17	Billing kWh	0	-	-	-	-	-	-	-
18									
19									

1. 8.0kW-DC represents the theoretical maximum output of the solar panels, in direct current before converting to alternating current, which carries a conversion efficiency of 60-90%.
2. 8.3kW-AC represents the maximum output of the 8.0kW-DC system after TEP's modifications have been applied. **<u>It is physically impossible for a 8.0kW-DC system to output 8.3kW-AC.</u>**

Screenshot location: Tab Load_PV XL

Through extensive modification, TEP's final solar profile is physically impossible

Load/PV System Summary:			
Large Customer Monthly kWh	1,500	From "R-01 Demand" tab	
Annual Customer Energy (kWh)	18,000		
Annual PV Production-South (kWh)	18,000	Note: Input for annual production in "Rate_PV Input" tab.	
Annual PV Production-West (kWh)	15,222		
System Size	10.00	kW-DC	1
Initial System Cost	$ 17,499.65		

	Day Count	365	31	28	31	30	31	30	31
			1	2	3	4	5	6	7
1	Description	Annual	January	February	March	April	May	June	July
2	Energy Use (kWh)	18,000	1,350	1,022	1,130	1,141	1,380	2,163	2,114
3	Total Peak Demand (kW)	7.82	6.43	5.64	5.64	5.71	6.73	7.82	7.40
4	Ratchet Minimum-Total (kW)	-	-	-	-	-	-	-	-
5	Net Demand at Peak (kW)	7.19	6.43	5.64	5.64	5.71	6.29	7.15	7.19
6	Ratchet Minimum-Net (kW)	-	-	-	-	-	-	-	-
7	Load Factor (Total Peak)	26.3%	28.2%	26.9%	26.9%	27.7%	27.6%	38.4%	38.4%
8									
9	Net Hourly Energy Delivered (kWh)	7,961	499	536	693	780	832	791	771
10	Net Hourly Energy Received (kBh)	7,959	661	688	702	688	688	683	616
11									
12	PV Output (kWh)	18,000	1,332	1,019	1,130	1,156	1,394	2,176	2,111
13	PV Output (max kW)	10.2	8.4	7.3	6.1	5.5	6.5	10.2	9.9
14	Capacity Factor	20.2%	21.3%	20.7%	24.7%	29.3%	28.7%	29.7%	28.8%
15									
16	Net-Metering Rollover	289	-	-	-	-	15	29	42
17	Billing kWh	21	18	3	0	-	-	-	-
18									
19									

2

1. 10.0kW-DC represents the theoretical maximum output of the solar panels, in direct current before converting to alternating current, which carries a conversion efficiency of 60-90%.
2. 10.2kW-AC represents the maximum output of the 10.0kW-DC system after TEP's modifications have been applied. **It is physically impossible for a 10.0kW-DC system to output 10.2kW-AC.**

Revision 2

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): K58:K8817

Description: Removed formulas to remove TEP's artificial scaling of solar profile.

Revision 3

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): M58:M8817

Description: Removed formulas to remove TEP's artificial scaling of customer usage profile.

Revision 4

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): N58:N8817

Description: Removed formulas to remove TEP's artificial scaling of customer usage profile.

Revision 5

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): O58:O8817

Description: Modified formulas to pull from actual usage profile instead of TEP's artificially modified usage profile.

Revision 6

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): P58:P8817

Description: Modified formulas to reference TEP provided unmodified solar profile and unmodified usage profile instead of TEP's artificially modified solar and usage profiles.

Revision 7

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): Q58:Q8817

Description: Modified formulas to reference TEP provided unmodified solar profile and unmodified usage profile instead of TEP's artificially modified solar and usage profiles.

Revision 8

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): E37:E48

Description: Removed hard coded monthly kWh values and replaced with formulas that sum for each month from the actual, unmodified usage profile in cells L58:L8817.

Revision 9

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): F37:F48

Description: Removed hard coded monthly kW values and replaced with formulas that find the maximum kW for each month from the actual, unmodified usage profile in cells L58:L8817.

Revision 10

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): H37:I48

Description: Removed formulas to artificially scale kWh and kW.

Revision 11

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): K37:M48

Description: Removed hard coded values for solar exported to the grid and solar used by the customer.

Revision 12

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): N37:N48

Description: Removed formulas referencing TEP's artificially modified solar production.

Revision 13

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): O37:O48

Description: Modified formulas to reference actual solar energy consumed by the customer, not TEP's artificially modified values.

Revision 14

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): P37:P48

Description: Modified formulas to reference actual solar energy exported to the grid, not TEP's artificially modified values.

Revision 15

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): E13:P13; E14:P14; E16:P16; E23:P23; E24:P24

Description: Modified formulas to reference TEP provided unmodified solar profile and unmodified usage profile instead of TEP's artificially modified solar and usage profiles.

Revision 16

Tab(s): Load_PV XS; Load_PV SM; Load_PV MED; Load_PV LG; Load_PV XL

Color:

Location(s): E27:P27

Description: Modified formulas to use the end of September as the net metering reset month per TEP's R-4 Rider. TEP's provided model used the end of December.

Revision 17

Tab(s): R-01 FRS Prop; R-01 NM Rollover; R-01 NM RCR; R-01FRS Dem; R-01 NM Dem RCR; R-01 NM Dem R-B; R-01 FRS Current; R-01 PRS NM Current; R-01 PRS RCR Current; R-01 FRS Dist; R-01 NM-R Dist

Color:

Location(s): F16:Q16

Description: Modified formulas to use the end of September as the net metering reset month per TEP's R-4 Rider. TEP's provided model used the end of December.

Revision 18

Tab(s): R-01 FRS Prop; R-01 NM Rollover; R-01 NM RCR; R-01FRS Dem; R-01 NM Dem RCR; R-01 NM Dem R-B; R-01 FRS Current; R-01 PRS NM Current; R-01 PRS RCR Current; R-01 FRS Dist; R-01 NM-R Dist

Color:

Location(s): E59; F58:Q58

Description: Modified formulas to use the end of September as the net metering reset month per TEP's R-4 Rider. TEP's provided model used the end of December.

EXHIBIT B

EXHIBIT B – TRADE TERMS

Q: How do you define the "value of solar" in your testimony?

A: Given the open dockets that share a similar title, I feel this is an important term to define. In my testimony, the "value of solar" is from the DG customer's perspective. To a DG customer, the value of a solar kWh is the average avoided retail cost rate ($/kWh) their solar array offsets from their utility bill. So, for example, if a residential DG customer's rooftop solar array generated 1,000 kWh in a month and reduced their electric bill from $150 to $30, the "value of solar" would be:

$$Value\ of\ Solar = \frac{(150 - 30)}{1000} = \$0.12/kWh$$

Q: What is a load profile?

A: A load profile is a set of kWh or kW values that represent customer usage in a given time interval. For example, an "hourly load profile" would show how much energy a customer consumed on hourly intervals. With an hourly load profile, one is able to easily extract kWh and average kW for each hour, as both values are the same.

Q: What is load factor?

A: In general terms, load factor is used to quantify the variability of a customer's load profile in a given period of time. Lower load factors generally mean a customer has a more volatile load profile and higher load factors mean the customer has a flatter load profile. Load factor is calculated with the following formula:

$$Load\ Factor\ (\%) = \frac{Average\ Demand\ (kW)}{Peak\ Demand\ (kW)}$$

So, if a customer's peak demand is 4 times greater than their average demand, their load factor will be 25%.

Q: How do you calculate average demand?

A: If you have energy usage over a specific period of time, you can calculate average demand with the following formula:

$$Average\ Demand\ (kW) = \frac{Usage\ (kWh)}{Total\ Hours}$$

Where Total Hours is the time period in which you measured Usage (kWh) measured in hours.

Q: What is Net Metering?

A: Net Metering is a concept in which a DG customer, when their DG solar array is generating more energy than their premises requires, is free to let the excess energy export to the utility grid. The utility is then free to sell the customer generated excess energy to another customer at a retail rate. Instead of expecting monetary compensation for this energy, DG customers "net" the excess energy against future times when their DG solar array is not sufficient to meet their local energy demands, and they request energy from the utility. The concept of netting exported energy against future retail energy is a core component to Net Metering. In my opinion, and what is common throughout the industry, trading an exported kWh in exchange for monetary compensation well below the retail rate (the

Company's RCR proposal) is labeled "Net Billing" and not considered a form of "Net Metering".

Q: What is a fixed charge?

A: A fixed charge is a set monthly fee the Company charges each customer regardless of their usage or demand.

Q: At what interval does the Company bill customers for peak demand?

A: Currently, the Company charges only large commercial customers for peak demand at a 15 minute interval.

Q: What is a ratchet?

A: A ratchet is a minimum billing demand based on historical demand outside of the current billing period. For example, if a customer required 100kW of demand 11 months ago, but only 30kW of demand in the current billing period, a ratchet would increase the billing period demand of 30kW to a billed value more in line with 100kW.

Ratchets typically vary in two ways:

- How far back the utility can look into historical demand
- What percentage of peak demand in the look back period is applied to the current billing period

EXHIBIT C

EXHIBIT C – RESIDENTIAL SSA ASSUMPTIONS

Return	Value	Unit
Target IRR	10%	%
System	**Value**	**Unit**
kW DC	5.60	kW
kW AC	5	kW
Yield	1,800	kWh/kW
Sites	1	EA
SSA	**Value**	**Unit**
Rate	$0.0935	$/kWh
Escalator	2%	%
Term	25	Years
COD Quarter	3	1 for Q1, 2 for Q2, etc
COD Year	2016	Year
COD Assumed Date	9/30/16	
SSA Extension Options	**Value**	**Unit**
Assume Residual Value?	No	
Term	0	Years
Rate	$0.000	$/kWh
Expenses	**Value**	**Unit**
EPC Price	$2.190	$/Wdc
O&M	$10.00	$/kWdc/Year
O&M Escalator	1%	%/Year
Replacement Value	$1.971	$/Wdc
Insurance Annual Rate	1%	% of Replacement Value
Insurance De-escalator	1%	% Annual Reduction
Inverter Replacement	$0.150	$/kWac
Start Year	10	Year
End Year	20	Year
Monitoring	$10	$/Month
Legal Closing Costs	$0	$/Closing

Tax	Value	Unit
Marginal Federal Tax Rate, Start	39.6%	%
Marginal State Tax Rate, Start	5.5%	%
Marginal Federal Tax Rate, End	39.6%	%
Marginal State Tax Rate, End	5.5%	%
Tax Rate Switch Year	6	Year
ITC Rate	30%	%
Y1 Usage	100%	%
Y2 Usage	0%	%
Y3 Usage	0%	%
Y4 Usage	0%	%
Y5 Usage	0%	%
Total Usage	100%	CAN NOT EXCEED 100%
ITC Ineligible Costs	$0	Total $
ITC/MACRS Basis	$12,264	
Property Tax?	Yes	
Depreciation Schedule	**Value**	**Unit**
Bonus Depreciation?	Yes	
Bonus Depreciation %	50%	Year 1 %
Custom Depreciation Schedule?	No	
Straight Line Term	15	Years
Miscellaneous	**Value**	**Unit**
Annual System Degradation	0.50%	%/Year

EXHIBIT D

TUCSON ELECTRIC POWER COMPANY
(GREATER THAN 50 kWac)
PV INTERCONNECTION APPLICATION

Customer Information

Business Name: _____

Customer Contact: _____

Mailing Address: _____

City: _____, **AZ** **Zip Code:** _____

Street Address: (if different from above) _____

Phone Number: _____

E-mail Address: _____

Solar - PV Equipment Information

Module Manufacturer: _____ **Nameplate DC Rating:** _____ **Watts**

Module Model Number: _____ **Quantity of Modules:** _____

Module Warranty: _____**years**

Inverter Manufacturer: _____ **Inverter Model Number:** _____

Inverter conforms to UL1741 for grid connected: _____**Yes** _____ **No**

Inverter Warranty: _____**years**

Project Information

Will system be grid connected: _____**Yes** _____ **No**

Meter Number: _____

Utilities Contact for system interconnection: _____ **Customer** _____ **Installer**

Has a City/County Permit been secured: _____**Yes** _____ **No**

Does this installation meet all TEP Interconnection Requirements: _____**Yes** _____ **No**

Estimated Installation Date: _____

System Cost: _____

Installer Information

Company Name: _____

Installer's Name: _____

Business Address: _____

Arizona Registrar of Contractors (AZROC) License Information

AZROC License Number: _____ **Class:** _____ **Expiration Date:** _____

Contractor's License: _____ **Class:** _____ **Expiration Date:** _____

Completed By: _____

TEP Customer Signature: _____

ATTACHMENT A

DISCLAIMER

POSSIBLE FUTURE RULES and/or RATE CHANGES AFFECTING YOUR PHOTOVOLTAIC (PV) SYSTEM

The following is a supplement to the Grid-Tied **Non-Residential** Solar Electric PV Application you signed with Tucson Electric Power Company (TEP).

1. Your PV system is subject to the current rates, rules and regulations established by the Arizona Corporation Commission (Commission). The Commission may alter its rules and regulations and/or change rates in the future. If this occurs, your PV system is subject to those changes and you will be responsible for paying any future increases to electricity rates, charges or service fees from TEP.

2. TEP's electricity rates, charges and service fees are determined by the Commission and are subject to change based upon the decision of the Commission. These future adjustments may positively or negatively impact any potential savings or the value of your PV system.

3. Any future electricity rate projections which may be presented to you are not produced, analyzed or approved by TEP or the Commission. They are based on projections formulated by external third parties not affiliated with TEP or the Commission.

Initials _____

In its pending rate case that was filed on November 5, 2015, TEP has asked the Commission for approval to change the retail customer credit for excess energy placed on the grid and to eliminate the monthly energy carryover (banked credits). These changes, if approved by the Commission, may affect your bill. Other parties participating in the rate case may recommend different proposals that may affect your bill in other ways. The Commission is not bound by any party's proposal and may accept, reject, or modify any proposed rate, charge or term of service.

Initials _____

By signing below, you acknowledge that you have read and understand the above disclaimer. Please return to TEP.

_____ _____

Main Customer's Printed Name Main Customer's Signature

_____

Installation Address

_____

Date

Rev. 12312015

ATTACHMENT B

System Qualifications, Electric Service Requirements and Interconnection Requirements

The installed PV system must at all times meet the system qualification requirements for commercial and grid-connected PV systems as set forth in the current "Electric Service Requirements", "Distributed Generation Interconnection Requirements" (DGIRs), and TEP's "Rules and Regulations", as amended from time to time, the terms of which are fully incorporated herein by reference (PV systems are defined as "Generating Facility" in the DGIRs). Complete copies of the "Electric Service Requirements" and "Distributed Generation Interconnection Requirements" conformed to ACC Docket No. E-00000A-99-0431 are located at https://www.tep.com/customer/construction/esr/ under the "Customer Care" - "Construction Services" tab. TEP's "Rules and Regulations" dated July 1, 2013 are located at https://www.tep.com/customer/rates/ under the "Rules and Regulations" tab. Customer acknowledges that it has adequate notice of and access to these online documents, has read the documentation, and waives any objection thereto. Hard copies will be provided upon request.

_____ _____

Main TEP Customer's Printed Name Main TEP Customer's Signature

_____

Installation Address

_____ _____

Date Installer

EXHIBIT E

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO SWEEP'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
June 1, 2016

SWEEP 2.15

Has TEP conducted analysis or reviewed previous pricing studies to determine if a three part rate is superior to a two part time of use rate in reducing peak demand? If yes, please provide analysis or cite studies reviewed. If no, please explain why this analysis was not conducted.

RESPONSE:

TEP has not conducted any analyses or reviewed previous studies to determine if a three-part rate is superior to a two-part time-of-use rate in reducing peak demand. TEP has not conducted or reviewed such a study because reducing peak demand is not the primary objective of TEP's proposed three-part rates for residential and small general service customers. While peak demand reduction may be a benefit of the proposed three-part rate, the main objective of TEP's proposal is to better align cost recovery with how costs are incurred.

RESPONDENT:

Rick Bachmeier

WITNESS:

Dallas Dukes

EXHIBIT F

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO SOLON'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 TUCSON ELECTRIC POWER RATE CASE
DOCKET NO. E-01933A-15-0322
June 13, 2015

SOLON 2.10

On page 19 of Susan Gray's Direct Testimony, she describes a "multi-year project to automate meter reading with the installation of a fixed meter reading network, and the replacement of all 400,000+ meters across TEP's service territory."

a. How many meters had been replaced as of the beginning of TEP's test year and how many have currently been replaced?

b. Please describe the shortest time interval in which TEP can monitor and record customer usage if a customer has an older style meter (that has not been replaced per the planned replacement project described by Susan Gray). Also please indicate if the functionality is different for an individual rate class, or if the customer is enrolled in the R-4 Net Metering Rider.

c. At the start of the test year, please indicate the number of meters in which TEP recorded usage for a GS-10 customer at the following intervals: instantaneous, 15-minute, hourly, daily, and monthly.

d. At the start of the test year, please indicate the number of meters in which TEP recorded usage for an R-01 customer at the following intervals: instantaneous, 15-minute, hourly, daily, and monthly.

RESPONSE:

a. As of July 1, 2014, 263,802 AMR meters had been installed. TEP currently (June 6, 2016) has 423,544 AMR meters installed.

b. An electromechanical meters that is not AMR is typically read monthly. These meters do not store interval data, so interval data is not available. We do not use electromechanical meters for Net Metering.

c. GS-10 Rate

	Meter Count
Instantaneous	0
15-Minute	10223
60-Minute	8887
Daily	0
Monthly	0

d. R-01 Rate

	Meter Count
Instantaneous	0
15-Minute	41763
60-Minute	163831
Daily	0
Monthly	0

RESPONDENT:

Susan Gray / Chris Fleenor

WITNESS:

Susan Gray

EXHIBIT G

GAMMAGE & BURNHAM, PLC
ATTORNEYS AT LAW
TWO NORTH CENTRAL AVENUE
FIFTEENTH FLOOR
PHOENIX, ARIZONA 85004-4470

TELEPHONE (602) 256-0566
FACSIMILE (602) 256-4475

WRITERS DIRECT LINE

June 13, 2016

Camila Alarcon
calarcon@gblaw.com

(602) 256-4417

VIA U.S. MAIL AND E-MAIL
mpatten@swlaw.com; jgellman@swlaw.com; bcarroll@tep.com; jhoward@swlaw.com; docket@swlaw.com

Michael W. Patten
Jason D. Gellman
Snell and Wilmer LLP
One Arizona Center
400 E. Van Buren St.
Phoenix, AZ 85004

Re: Third Set of Discovery Requests
SOLON Corporation to Tucson Electric Power Co.
Docket No. E-01933A-15-0239/E-01933A-15-0322
[Tucson Electric Power Co.]

Dear Mike, Jason, and Brad:

Below please find SOLON Corporation's third set of discovery requests to Tucson Electric Power Co. in the above-referenced consolidated cases.

3.1 In the file "2015 TEP R-01 Demand-PRS.xlsx," there are references throughout the Load_PV Mean, Load_PV Median, Load_PV XS, Load_PV SM, Load_PV MED, Load_PV LG, Load PV XL tabs to a "2014 Res Avg Hourly Profile," "2014 Solar Billing Dets," and "PV kwh/kBh Data." These references are located in cells L58:L8817, E37:F48, and K37:M48, respectively. Please provide the complete data set these values from which were derived in Microsoft Excel format, unlocked, and with formulas intact. To clarify, and as an example, in sheet "Load_PV XS," the 2014 Solar Billing Dets is referenced as the 10th percentile, and the 2014 Res Avg Hourly Profile is referenced as the 25th percentile. This indicates a larger data set was used to arrive at these profiles, and we are seeking the complete data set used.

3.2 In the file "2015 TEP GS-10 Demand-PRS.xlsx," there are references throughout the Load_PV Mean, Load_PV Median, Load_PV XS, Load_PV SM, Load_PV MED, Load_PV LG, Load PV XL tabs to a "2014 Res Avg Hourly Profile," "2014 Solar Billing Dets," and "PV kwh/kBh Data." These are located in cells L58:L8817, E37:F48, and K37:M48, respectively.

a) Please provide the complete data set from which these values were derived in Microsoft Excel format, unlocked, and with formulas intact. For example, in sheet "Load_PV XS," the 2014 Solar Billing Dets is referenced as the 30th percentile, and the 2014 Res Avg Hourly Profile is referenced as the 50th percentile. This indicates a larger data set was used to arrive at these profiles, and we are seeking the complete data set used.

b) If TEP's data set used in this Excel file assumes a number of their current GS-10 customers would be switched to a different rate plan under the proposal, and those profiles are excluded from the data set, please provide the profiles for all customers assumed to be switched to a different rate plan in a separate file.

Please do not hesitate to contact me if you have any questions or need clarification regarding any of these requests.

Sincerely,

GAMMAGE & BURNHAM, P.L.C.

By
Camila Alarcon

CA/bjs

EXHIBIT H

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

STF 20.08

Rate Design: Follow-up STF 1.61 – Please provide details of the discussions held with customers that may see "large rate increases".

a. How were those customers provided notice of the proposed MGS schedule?

b. How many customers were provided notice of the proposed MGS schedule?

c. How many customers will be affected by the proposed MGS schedule?

d. Please provide any individual customer rate impact analyses.

e. Please provide any other rate impact analyses performed.

RESPONSE:

a.-b. Pursuant to the Procedural Order that was issued by the Administrative Law Judge in this docket, all customers were provided notice of the Company's rate application via bill inserts and newspaper publication. The notice provided information as to where and how customers could review the various proposals and schedules set forth in the application. Other than through normal rate case notification processes, no advance notices have been offered to customers who may be migrated to the MGS rate to-date. The MGS rate schedule is being proposed for the first time for approval in this proceeding and the precise customers who may be eligible to migrate to this new rate will depend on the final resolution of revenue requirement and rate design in this proceeding, which is still only in the discovery process. Once the particulars of the new rate and more recent customer usage data has been reviewed, the Company will contact affected customers in writing on or before Commission approval if it appears any of the customers will experience increases above normal.

c. The Company estimated that 43,456 bills during the test year would have been from customers in the MGS class. Assuming each customer received 12 bills in the year, 3,621 customers would be on the proposed MGS rate.

d. The Company has not directly retrieved hourly data to evaluate customer impacts from the movement to MGS rates. The Company has, however, extensively modeled commercial customer demand consistent with the response to STF 1.55. Through cursory exploration, the Company was able to determine there was a set of highly seasonal customers which would be affected by the move to a ratcheted demand rate. Because the aim of these analyses was to estimate total MGS demand, individual bill estimates were not performed.

e. Comparison rates from current to proposed and bill impacts are included in Schedule H-3 and H-4 filed with the Company's application.

RESPONDENT:

(a-b, e) Brenda Pries/ (c-d) Greg Strang

WITNESS:

Craig Jones

EXHIBIT I

VS 2.10

On page 12 lines 15-16 Mr. Dukes references 1,308,714 bills issued by TEP during the test year for 400kWh or less. Please indicate the number of these bills that were attributable to NEM customers.

RESPONSE:

Of the 1,308,714 residential R-01 bills for 400 kWh or less, 54,771 were from net metering customers.

RESPONDENT:

Anne Trostle

WITNESS:

Dallas Dukes

EXHIBIT J

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.11

Residential Customers - RE: Dukes Direct at page 11:22-25, please provide the following:

a. the number of seasonal residential customers that TEP has together with their energy use, by month, for a typical year;

b. the number of year round residential customers that TEP has together with their energy use, by month, for a typical year;

c. the estimated number of residential vacant homes, by month, for the years 2011-2015.

d. Please provide typical load profiles for a residential seasonal customer, a residential vacant home, a residential year round customer, and a residential customer with distributed generation. The load profiles should be for the winter period, the summer period, and the peak day.

RESPONSE:

a./b. The Company does not currently track seasonal versus year round customers and therefore does not have their energy use as requested.

c. The Company does not track vacant homes.

d. For the reasons above, the company does not have load profiles for the requested customer types. The company has a large swath of hourly data for a number of customers which include some of the customer types listed. Although there are not distributed generation customers in the sample, the Company is also including the NREL SAM 8760 production curve for the Tucson area for use in estimating solar DG customer hourly load shapes.

Please see the following files for the 8760 production curve.

File Name	Bates Numbers
RUCO 7.11 Individual Customer Sample 2-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 3-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 4-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 5-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample-Confidential.xlsx	N/A
RUCO 7.11 NREL SAM DATA-Confidential.xlsx	N/A

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT K

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO VOTE SOLAR'S SECOND SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322
June 1, 2016

VS 2.44

Regarding the work papers entitled "TEP 2015 RES Load-PV data.xlsx" and "TEP 2015 SGS Load-PV data.xlsx"

a. Please indicate whether these work paper contain any usage data from TEP's NEM customers.

b. Please indicate whether and how the various regression analyses shown in these work papers were used in the application. Please explain your answer.

c. Please indicate whether any hourly usage data is available for TEP's NEM customers, if so please describe the data that is available and provide all data available for TEP's NEM customers during the test year period.

d. Please describe the billing and/or usage data that is available for TEP's NEM customers during the test year.

e. Please indicate whether any data on TEP's NEM customers' kW demand either NCP or during the peak period exists.

f. Please provide all available data on NEM customers' on-site consumption, PV generation, delivered energy, exported energy, max kW during the peak period, max kW during the billing month. Please provide data on each available customer on an hourly, monthly and annual basis.

RESPONSE:

a. None of the customers in the samples were identified as TEP NEM customers.

b. The regression analyses were used to estimate parameters for the nonlinear relationship between average monthly kWh usage and average monthly load factor. If a satisfactory relationship was found, the parameters were used as the basis for applying average load factors to average monthly kWh for the purpose of bill impact comparisons. For both the RES and SGS sample data, the power regression of the form y = a*x^b yielded the best fit where "a" and "b" are the estimated parameters, "y" is average monthly load factor, and "x" is average monthly kWh.

c. Hourly usage data was not retrieved for NEM customers. However, due to the lack of an incentive to change hourly consumption habits with full-retail net-metering, it is unlikely that customers will significantly change their hourly usage habits. Thus it is possible to model NEM customer's consumption using non-NEM customer's consumption by layering in a solar generation profile which provides a simple way to track site consumption, site imports, and site exports.

d. The billing data available to the Company for NEM customers is the customers "kWh" which is the total energy that flowed into the meter and the "kBh" which is the total energy that flowed out of the meter. The production data from the NEM systems exists but it is not a billing item and is not easily linked to the customers billing data.

e. The data exists in the Company's meter data management system for customers who have the proper meter configuration, but due to the difficulty of retrieving the data, the Company does not have the data available. These items can be accurately modeled with the Company's data on hourly customer usage and a solar generation profile.

f. All of the above variables can be modeled from the data provided in RUCO 7.11. It is unnecessary to retrieve the data specifically from NEM customers for the reasons listed in the previous parts. If Vote Solar does not wish to model these variables themselves, the file TOU Solar TEP Residential.xlsx (provided in UDR 1.001) contains the data in a monthly summary form.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes