ORIGINAL

0000169550

BEFORE THE ARIZONA CORPORATION COMMISSION

RECEIVED
AZ CORP COMMISSION
DOCKET CONTROL

2016 APR 7 PM 3 15

COMMISSIONERS

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

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION.	DOCKET NO. E-00000J-14-0023 **STAFF'S NOTICE OF FILING REBUTTAL TESTIMONY**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Rebuttal Testimony of Staff witnesses Howard Solganick and Zachary Brahum in the above docket.

RESPECTFULLY SUBMITTED this 7th day of April 2016.

Maureen A. Scott, Senior Staff Counsel
Matthew Laudone, Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Arizona Corporation Commission
DOCKETED
APR 07 2016
DOCKETED BY

Original and thirteen (13) copies of the foregoing filed this 7th day of April 2016 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copy of the foregoing emailed **ONLY** this 7th day of April 2016 to:

Dillon Holmes
Clean Power Arizona
9635 North 7th Street #47520
Phoenix, Arizona 85068
dillon@cleanpoweraz.org
Consented to Service by Email

C. Webb Crockett
Patrick J. Black
Fennemore Craig, PC
2394 East Camelback Road, Suite 600
Phoenix, Arizona 85016
wcrockett@fclaw.com
pblack@fclaw.com
Attorneys for Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition
Consented to Service by Email

Court S. Rich
Rose Law Group pc
7144 East Stetson Drive
Suite 300
Scottsdale, Arizona 85251
crich@roselawgroup.com
Attorney for the Alliance for Solar Choice
Consented to Service by Email

Jennifer A. Cranston
Gallagher & Kennedy, PA
2575 E. Camelback Road, 11th Floor
Phoenix, Arizona 85016-9225
jennifer.cranston@gknet.com
Consented to Service by Email for Grand Canyon State Electric Cooperative Association, Inc.
Also Attorney for AEPCO and Dixie Escalante Rural Electric Association, Inc. who have not consented to Email service

Craig A. Marks
Craig A. Marks, PLC
10645 North Tatum Boulevard
Suite 200-676
Phoenix, Arizona 85028
Craig.Marks@azbar.org
Consented to Service by Email

Daniel W. Pozefsky, Chief Counsel
Residential Utility Consumer Office
1110 West Washington, Suite 220
Phoenix, Arizona 85007
dpozefsky@azruco.gov
Consented to Service by Email

Meghan H. Grabel
Osborn Maledon, PA
2929 North Central Avenue, Suite 2100
Phoenix, Arizona 85012
mgrabel@omlaw.com
gyaquinto@arizonaic.org
Consented to Service by Email

Timothy M. Hogan
Arizona Center for Law in the Public Interest
514 W. Roosevelt
Phoenix, Arizona 85003
thogan@aclpi.org
rick@votesolar.org
briana@votesolar.org
ken.wilson@westernresources.org
Consented to Service by Email

Jeffrey W. Crockett
CROCKETT LAW GROUP, PLLC
2198 E. Camelback Road, Suite 305
Phoenix, AZ 85016- 4747
Attorney for Sulphur Springs Valley Electric Cooperative, Inc.
jeff@jeffcrockettlaw.com
kchapman@ssvec.com
jblair@ssvec.com
Consented to Service by Email

Bradley S. Carroll
Tucson Electric Power Company
88 E. Broadway Blvd., MS HQE910
P.O. Box 711
Tucson, Arizona 85702
bcarroll@tep.com
mpatten@swlaw.com
jhoward@swlaw.com
Consented to Service by Email

Thomas A. Loquvam
Thomas L. Mumaw
Melissa M. Krueger
Pinnacle West Capital Corporation
400 N. 5th Street, MS 8695
Phoenix, Arizona 85004
Attorneys for Arizona Public Service Company
thomas.loquvam@pinnaclewest.com
Thomas.Mumaw@pinnaclewest.com
Melissa.Krueger@pinnaclewest.com
Consented to Service by Email

Tom Harris, Chairman
Arizona Solar Energy Industries Association
2122 West Lone Cactus Drive, Suite 2
Phoenix, Arizona 85027
Tom.Harris@AriSEIA.org
Consented to Service by Email

Copy of the foregoing emailed and/or mailed this 7th day of April 2016 to:

Garry D. Hays
The Law Offices of Garry D. Hays, PC
2198 E. Camelback Road, Suite 305
Phoenix, Arizona 85016
ghays@lawgdh.com

Greg Patterson
Water Utility of Arizona
916 West Adams, Suite 3
Phoenix, Arizona 85007
Gpatterson3@cox.net

Michael W. Patten
Jason Gellman
Timothy J. Sabo
Snell & Wilmer LP
One Arizona Center
400 E. Van Buren, Suite 1900
Phoenix, Arizona 85004
mpatten@swlaw.com
jgellman@swlaw.com
tsabo@swlaw.com

Gary Pierson
Arizona Electric Power Cooperative, Inc.
P.O. Box 670
1000 S. Highway 80
Benson, Arizona 85602
gpierson@azgt.coop

Charles C. Kretek, General Counsel
Columbus Electric Cooperative, Inc.
P.O. Box 631
Deming, New Mexico 88031-0631
chuckk@col-coop.com

LaDel Laub
Dixie Escalante Rural Electric Association
71 E. Highway 56
Beryl, Utah 84714
ladell@dixiepower.com

Steven Lunt, Chief Executive Officer
Duncan Valley Electric Cooperative, Inc.
379597 AZ 75
P.O. Box 440
Duncan, Arizona 85534
stevel@dvec.org

Dan McClendon
Garkane Energy Cooperative
P.O. Box 465
Loa, Utah 84747
dan@garkaneenergy.com

William P. Sullivan
Law Offices of William P. Sullivan, PLLC
501 East Thomas Road
Phoenix, Arizona 85012-3205
Attorneys for Garkane Energy Cooperative, Inc.; Mohave Electric Cooperative, Inc.; Navopache Electric Cooperative, Inc.
wps@wsullivan.attorney

Than W. Ashby, Office Manager
Graham County Electric Cooperative, Inc.
9 W. Center Street
P.O. Drawer B
Pima, Arizona 85543
tashby@gce.coop

Tyler Carlson, CEO
Peggy Gillman, Manager of Public Affairs
Mohave Electric Cooperative, Inc.
P.O. Box 1045
Bullhead City, Arizona 86430
tcarlson@mohaveelectric.com

Roy Archer, President
Morenci Water and Electric Company and Ajo Improvement Company
P.O. Box 68
Morenci, Arizona 85540
Roy_Archer@fmi.com

Charles R. Moore
Navopache Electric Cooperative, Inc.
1878 W. White Mountain Blvd.
Lakeside, Arizona 85929
cmoore@navopache.org

Vincent Nitido, CEO/General Manger
Trico Electric Cooperative, Inc.
8600 W. Tangerine Road
Marana, Arizona 85658
vnitido@trico.coop

David G. Hutchens, President
Kevin P. Larson, Director
UNS Electric, Inc.
88 E. Broadway Blvd., MS HQE901
P.O. Box 711
Tucson, Arizona 85701-0711

Patricia Ferre
P.O. Box 433
Payson, Arizona 85547
pferreact@mac.com

Nancy Baer
245 San Patricio Drive
Sedona, Arizona 86336

Michael Alan Hiatt
Earthjustice
633 17th Street, Suite 1600
Denver, Colorado 80202
mhiatt@earthjustice.org

Lewis Levenson
1308 E. Cedar Lane
Payson, Arizona 85541
equality@centurylink.net

Richard Adkerson
Ajo Improvement Company
333 N. Central Avenue
Phoenix, Arizona 85004-2189

Susan H. and Richard Pitcairn
1865 Gun Fury Road
Sedona, Arizona 86336
susan@susanpitcarin.com

Chinyere Ashley Osuala
Earthjustice
48 Wall Street, 19th Floor
New York, New York 10005
cosuala@earthjustice.org

Nicholas J. Enoch
Lubin & Enoch, P.C.
349 North 4th Avenue
Phoenix, Arizona 85003
nick@lubinandenoch.com

Karyn Christine

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION))))	DOCKET NO. E-00000J-14-0023

REBUTTAL TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 7, 2016

TABLE OF CONTENTS

EXECUTIVE SUMMARY
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023

Mr. Solganick's rebuttal testimony details Staff's recommendations for the attributes needed to derive the value and costs of DG in general and DG solar in particular.

Staff offers its perspective of the positions of various parties and analyzes the suggested methodologies in the context of utility planning, operations and cost recovery. Staff also responds to the positions of the various parties.

Staff also responds to some of the questions posed by Commissioners Forese, Burns and Stump.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, Pennsylvania 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. ("Blue Ridge").

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously provided direct testimony relating to value and cost of solar and addressed some of Commissioner Little's questions.

Q. What is the purpose of your rebuttal testimony?

A. This testimony provides Staff's response to the direct testimony filed by some of the interveners and also responds to questions from Commissioners Forese, Burns and Stump.

REBUTTAL TESTIMONY

Q. What conclusions and recommendations did Staff draw in its direct testimony?

A. Staff provided its perspective of the relative value and cost of various forms of distributed generation "(DG") including drawing contrasts between various types of generation and defining various drivers of value and cost.

Staff's perspective is based on specific concepts:[1]

- What happens behind the meter is the customer's business.
- The proper rate structure will offer accurate price signals to assist customers to make decisions between, for example, conservation, insulation, high efficiency appliances, storage or DG.
- Rates for residential and small general service customers will transition to Three-Part Time of Use ("TOU").
- Costs and values are to be viewed from the perspective of all customers.
- Utilities have a responsibility (enforced by the Commission) to provide service at the lowest reasonable cost.

[1] Solganick Direct 7:7

Q. Did Staff define DG and a number of terms that are relevant for the value and cost determination?

A. Yes. Staff developed its matrix[2] that compared and contrasted various forms of DG including generation, load shifting, storage, multiple forms of DG solar, wind, conservation, insulation, efficient appliances and efficient HVAC. The purpose of the Staff's matrix is to highlight that solar DG and many other alternatives offer similar attributes (to different degrees). Based on the matrix Staff drew many conclusions that are important when determining value and cost.[3]

Q. What elements did Staff recommend to set the price for excess DG energy?

A. The price offered should begin with avoided energy costs along with appropriate losses specific to that utility and/or its interconnected systems. The price should be further increased for the demonstrated or forecast capacity value for generation.[4]

If the deferral or elimination of transmission or distribution assets and/or costs is applicable then these value components should be geographic adders.[5] Geographic values should be treated as distinct adders and not accrue to all energy delivered because the deferral of transmission and/or distribution assets (or operational savings) is dependent on location.[6] Staff suggested that the utility should consider a feeder focused adder to attract DG in certain distribution locations, however there may be a threshold amount of demand that the DG should offset for the adder to apply.[7]

---

[2] Solganick Direct Exhibit HS-3
[3] Solganick Direct 14:15
[4] Solganick Direct 19:12
[5] Solganick Direct 19:19 and 19:24
[6] Solganick Direct 12:1, 15:1 and 15:4
[7] Solganick Direct 19:24

Environmental costs are included in the avoided cost value and therefore no additional value is needed. If an emerging environmental cost will affect future energy and capacity then that information should be made available from the Integrated Resource Plan ("IRP") process.[8]

Q. Which components of Staff's matrix are recommended for inclusion in the development of values and costs?

A. The following elements from the Staff matrix should be included to develop the base value of DG. Staff's matrix should be used to define what each form of DG provides value, as each type of DG has a different value proposition.

- Energy
  - (On & Off Peak) based on avoided cost including time dependency (recognizing the value based on when the energy is delivered)
- Capacity
  - Long-term based on ELCC when capacity is needed
- Environmental
  - Presently included in avoided cost (SOX, NOX, water, land use, etc.) therefore no additional value is needed
  - Potentially a carbon component based on the IRP process and emerging regulation

The addition of losses is appropriate but they should be applied based on a specific study (utilities generally have an energy loss study (and many have a demand loss study) that is used in the cost of service process).

- Energy
  - Losses adjusted for geographic location using the energy loss study

[8] Solganick Direct 20:4

- Capacity
  - Losses adjusted for geographic location using the demand loss study.

There are a number of geographic adders that may be effective in specific demonstrated locations.

- Transmission
  - Long-term based on ELCC when capacity is needed and can be offset if there is a true reduction in transmission costs and not a reallocation due to lower energy sales.
- Distribution
  - Long-term based on ELCC when capacity is needed and can be offset.

There are a number of emergency capabilities that could also apply to some forms of DG that can be controlled by the utility (see Staff's matrix for applicability guidance and Staff's discussion of "responsive"[9]).

- Energy
  - Positive (value) if output can be increased under utility control.
  - Negative (cost) if output cannot be decreased under utility control.
- Capacity
  - Positive (value) if output can be increased under utility control.
- Transmission
  - Positive (value) if output can be increased under utility control.
- Distribution
  - Positive (value) if output can be increased under utility control.

[9] Solganick Direct 12:7

There are grid support services that could also apply to some forms of DG that can be controlled by the utility (see Staff's matrix for applicability guidance). Some of these capabilities are included in the avoided cost of a utility generation facility; therefore the absence of these may be a cost to deduct. As the Commission evaluates whether these items have value when provided by the alternate technology, it should look to the present state to see if this value is being delivered now rather than presupposing that the market will evolve and deliver these capabilities.

- Reactive if available under utility control and needed geographically.
- Frequency Regulation if available under utility control.
- Operating (spinning) reserves if available under utility control.
- Market price response if measureable and not already within the avoided cost (short term effects).

There are customer costs to recognize as either per customer (unless judged to be very minor) or for connection of the DG facility.

- Metering & Reading
- Billing (costs of applying bill credits and software changes to accomplish)
- Customer Service
- Interconnection (based on geographic location with recognition of congestion costs or needed investments)

Staff does not recommend providing a value for social costs such as local economic development as these items are difficult to quantify and not included in the ratemaking formula for existing generation and other facilities and not unique or incremental in DG.

Q. What is the impact of RECs?

A. The compensation for energy should reflect whether RECs are delivered to the utility or retained by the customer.[10]

Q. Are there any reliability or resiliency benefits to DG solar as presently configured?

A. Staff addressed this issue in its response to Chairman Little's question.[11] At present few, if any, DG solar installations offer reliability and resiliency benefits and the technology if developed in the future will primarily benefit the DG customer, therefore there is no basis to pay for a value that does not provide a benefit to non-participating customers. Customers that are concerned about reliability beyond that provided by their utility often purchase at their own expense backup sources of electricity or make appropriate plans to deal with the emergency, therefore adding a value component is inappropriate. The presence of non-utility generation on the grid complicates (and slows down) restoration due to requirements for clearances to maintain safety of line workers.

Q. Does Staff's recommended values and costs impact the value of DG used behind the meter?

A. No. The value of any DG used behind the meter is determined by the customer and the rate schedule the customer purchases energy and capacity on.

Q. Are there other mechanical and/or rate setting issues involved?

A. Yes. Staff's direct testimony addresses a number of procedural issues.[12]

---

[10] Solganick Direct 20:7
[11] Solganick Direct 27:9
[12] Solganick Direct 18:23 through 19:10

Q. Are all utilities alike?

A. Staff recognizes that each utility operates under different circumstances and challenges. The customer density of various utilities varies and leads to different transmission and distribution configurations that will have an impact on geographic based costs including interconnection. The utility's metering capabilities will also determine how detailed costs can be defined and the corresponding rate design in place.

Q. Are all DG resources alike?

A. Staff's matrix demonstrates that there are a large number of types of DG with varying characteristics, capabilities and attributes. Additionally, there can be geographical differences among DG types that further affect performance. For DG solar there can be utility-scale, community scale, residential and commercial and industrial ("C&I").

Utility-scale would generally be connected at a substation and depending on size would support loads at that substation or connected substations. Due to the economies of scale and location, the utility-scale solar can utilize tracking to maximize production and produce energy earlier in the morning and later in the afternoon thus offering both energy and better support of the utility's peak demand.

Community-scale solar may be located closer to the load and may be smaller than utility-scale but can have similar attributes including increased production and better contribution to peak demand due to tracking. Community-scale solar would typically use less of the transmission system and have lower losses to the load.

Utility-scale and community-scale solar benefit from economies of scale, which lowers costs and allows the use of smart inverters and other controls to tailor performance to the needs of the distribution system such as providing voltage control and reacting to emergency conditions.

Solar behind a customer's meter is generally smaller in size and more costly per kW. Tracking is usually not used and in many areas the orientation of the panels has focused on maximum energy production (south) rather that meeting demand (west). Losses due to distribution feeder conductors are reduced compared to community-scale solar but distribution transformation losses may be double (out then in) depending on customer density. Notably behind the meter customer systems provide excess energy as the net of solar production less the customer's internal load. Due to differences in load profile it is inappropriate to aggregate residential and C&I systems within the same price structure as that will shift benefits between two distinct customer classes.

Q. What are the points of agreement among the parties in this case?

A. The parties to this case, in general, agree that the price for excess energy delivered to the grid should include:

- Avoided energy costs and appropriate losses.
- Deferrable capacity costs including losses (based on ELCC).

Q. What are the points of partial agreement among the parties in this case?

A. The parties to this case, in general, accept the concept, but do not agree on significant issues, relating to the price for excess energy delivered to the utility grid that might include:

- Transmission capacity costs including losses but the methodology for computing the value differs based on
  - Lumpiness of assets versus continuous value
  - Valuing deferral before need

    - Level of penetration

- Distribution capacity costs including losses but the methodology for computing the value differs based on
    - Lumpiness of assets versus continuous value
    - Valuing deferral before need
    - Level of penetration

Q. What are the points of disagreement among the parties in this case?

A. There is a dichotomy among the parties to this case, in general, with only TASC and VS suggesting the inclusion of values such as:

- Additional environmental benefits above regulations in place (such as SOX/NOX and proposed carbon costs)
- Improved electric reliability
- Improved system operations
- Economic development benefits
- Using near term DG penetration

Q. Why do your reviews not include rate design, net metering and associated items?

A. Staff has held the position that the specific value of DG and the associated rate design should be approved in the context of a rate case.[13] Staff has provided its rate design and net metering positions in the on-going UNS Electric rate case (15-0142), the Sulphur Springs Valley Electric Cooperative rate case (15-0312) and will be providing its position in the Tucson Electric Power rate case (15-0322). Arizona Public Service is due to file its rate case in June 2016 and Staff expects to provide its position in that upcoming rate case.

[13] Solganick Direct 4:22

Q. What is resource lumpiness?

A. Utility scale resources often come in discrete sizes leading to lumpiness in the planning process. For example, gas turbines come in discrete MW sizes, as do combined cycle plants and some baseload generation. Transmission capability is often determined by voltage and conductor size again resulting in discrete sizes.

Q. Why is resource lumpiness problematic?

A. In order for a technology to reliably replace the utility resource the technology must demonstrate the certainty that the alternate technology will reach the needed penetration to displace the utility resource. If the alternate technology does not ultimately reach the needed size then it only delays the resource but does not eliminate it.

Q. Are there timing constraints associated with resource development?

A. Yes. The development of a major resource may require siting, permitting, engineering and construction before the resource can be placed into service. Therefore the valuation process should consider that the initial steps in resource development may occur and then a sufficient volume of alternate resources might supplant the construction of the resource. In this situation the costs of siting, permitting and engineering may not be avoidable but may need to be performed as a contingent expenditure to allow the utility to be ready should the distributed resources not materialize in time to meet customer needs. Staff recommends that if these costs are not avoidable then they should not be included in the value proposition.

Q. Does the suggested use of long-term forecasts generate concern about their application?

A. Yes. RUCO, TASC and VS recommend the use of a 20 to 30 year horizon[14] and RUCO[15] and VS[16] suggest that the value of avoided energy be levelized for excess energy supplied by DG solar.

Q. **Does Staff agree?**

A. This suggestion brings several concerns into focus.

Unlike utility or community-scale DG solar, the output of rooftop DG solar is the net of the production less customer usage. There is no requirement that the DG solar customer deliver a specified portion of the production over the life of the installation. There is the potential for the DG customer to respond with a "snapback" effect, which is when a customer sees how much they are saving they use some incremental energy as compensation for their efforts. The increased "compensation" might be lowering the thermostat by one or more degrees during the summer season and thus reducing the excess energy delivered to the utility grid. In the future a solar DG customer may decide to switch to an electric vehicle and reduce the excess energy delivered to the utility grid. Advocates of levelizing energy savings may not recognize that these later events distort the levelization of value.

Although RUCO supports a twenty-year horizon it takes a less expansive view of costs and benefits and proposes to include only easily quantifiable costs and benefits and focus on categories related to the energy system.[17]

---

[14] Huber Direct 13:7, Beach Direct 18:12 and Kobor Direct 23:1
[15] Huber Direct 12:26
[16] Kobor Direct 22:24
[17] Huber Direct 13:7

Before any long-term view is taken, the life of the alternate technology should be explored to ensure it matches the term used in the analyses.

Staff recommends that a long-term analysis be undertaken with great care because of the potential for overpayment. The use of too low or too high of a discount rate should be avoided as this tilts the valuation higher. By revisiting the valuation in the utility's rate case, values can be increased if avoided costs rise in the future beyond the forecast used in the previous case.

Q. TASC and VS recognize that the analysis they are recommending may require additional data that utilities are not presently using. Does this create a concern?

A. Yes. Moving the level of analysis that utilities perform forward is a reasonable consideration but the cost, pace and usefulness for utility customers must be considered. TASC acknowledges that some of the data needed to bolster or raise the value of DG solar is not presently available in utility planning.[18] VS wants third party review and funding for that additional review.[19]

Staff recommends that any discussion of enhanced analysis take place within the IRP process.

Q. Both TASC and VS envision the use of smart inverters and storage as solutions to various issues.[20] Should these solutions be used to recognize value now?

A. This issue is better addressed in rate cases wherein the value of DG solar or other technologies are quantified and approved. Staff's recommended Three-Part TOU rate design and net metering price the value of both demand and energy to allow all customers to make

[18] Beach Direct 22:1
[19] Kobor Direct 5:13
[20] Beach Direct 31:1 and Volkmann Direct 13:3

choices in their usage, time of usage and intensity of usage. Storage technology is one way for all customers to make economic decisions that are rewarded by this rate design.

Staff[21] and APS[22] have recognized that there are emergency conditions such as Low Load (excess generation) that may be partially alleviated by coordinated actions from smart inverters. However, until the solar DG industry demonstrates that the technology can be controlled and includes smart inverters as standard equipment, Staff recommends that it may be more appropriate to subtract value from DG solar for its inability to react to this emergency condition unlike some other forms of generation and storage.

Q. TASC suggests that there is a fuel hedge value to DG solar[23] that should be measured and used to increase the price of excess energy. Does Staff agree?

A. I have seen little evidence that electric utility customers are demanding more reduction in long-term pricing volatility. In competitive supply states residential contracts appear to extend out a few years at most. Utility energy adjustment programs are generally annual or even shorter durations. Staff suggests electric customers do not value a partial fuel price hedge and one should not be applied.

Q. TASC suggests that there is a market price mitigation value of DG solar[24] that should be used to increase the price of excess energy. Is this function unique to DG solar or measurable?

A. The suggestion appears to be that DG solar reduces the load on the grid and therefore reduces the energy price level for all customers. This economic concept is hard to measure and confirm. DG solar is inferior in this respect compared to other forms of DG as shown

[21] Solganick Direct 13:9 and Exhibit HS-3
[22] Albert Direct 14:8
[23] Beach Direct 20-21 Table 2
[24] Beach Direct 20-21 Table 2

in Staff's matrix. Increased insulation, efficient appliance and efficient HVAC provide this response on a more certain basis as the load reduction effects of these measures are more predictable and less subject to customer's future actions. Responsive DG when called on also could provide this effect. DG solar may provide this effect subject to the DG customer's usage. On hotter days the amount of excess energy may be reduced to serve the increased needs of the DG customer. Based on the limited estimation of the effect and the likely more predictable response of other forms of DG compared to DG solar, Staff recommends this concept should not be used to increase the value of DG solar excess energy.

Q. VS suggests analyzing the value of DG solar using current penetration but then asserts that the analysis be over a long-term. Does this create a dichotomy?

A. Yes. VS focuses on the present for the estimation of solar DG penetration.[25] It also suggests that the analysis be over a twenty to thirty year term.[26] TEP suggests that as penetration of DG solar rises the peak may shift later into the evening.[27] If this is the case then the ELCC of DG solar will decrease (potentially to zero) and reduce the capacity value.

VS' suggestion to use current penetration levels also removes from the analysis the costs of congestion on feeders and impacts on system operations due to higher penetration of DG production and excess energy. This suggestion will cause the costs due to DG solar to be understated. Staff recommends that the level of penetration be synchronized with the period of analysis to properly match value and costs so that analyses are internally consistent.

---

[25] Kobor Direct 24:7
[26] Kobor 23:1
[27] Tilghman 21:10

Q. Please provide a review of Arizona Public Service ("APS") witness Leland R. Snook's direct testimony.

A. APS witness Snook states the Cost of Service Study ("COSS") "does not consider environmental or economic development benefits because they are not part of the cost to serve customers. They are intangible and unquantifiable values. If they are to be considered at all, they are more appropriately considered in a resource planning context when comparing resource alternatives."[28] He also provides an estimate of the percentage of a DG solar installation's capacity that offset's generation requirements as "at most 19 percent".[29]

Q. Please provide a review of APS witness Bradley J. Albert's direct testimony.

A. APS witness Albert recognizes that energy losses are reduced when energy is consumed at the same site because this power does not have to travel across the grid.[30] His short-term estimate is 7 percent over a year and 12 percent at the time of peak demand.[31] He reminds us some other generation sources do not emit CO2 or other types of emissions. These generating sources include solar, wind and nuclear.[32] He also discusses the need to curtail energy production[33] a condition that Staff discussed in its direct testimony[34]. He suggests three potential ways to estimate the value of rooftop solar based on short-term avoided costs (time varying energy market costs), long-term avoided costs (resource planning) and grid-scale adjusted cost (market competitive).[35]

---

[28] Snook Direct 18:7
[29] Snook Direct 18:19
[30] Albert Direct 8:25
[31] Albert Direct 24:1
[32] Albert Direct 13:23
[33] Albert Direct 14:8
[34] Solganick Direct 13:9
[35] Albert Direct 16:18

Staff's initial testimony recommended the recognition of losses and its matrix highlighted the differences and similarities of various alternatives. Staff is willing to consider the use of a comparative resource to benchmark the value of DG.

Q. Please provide a review of APS witness John Stirling's direct testimony.

A. APS witness Stirling describes the process used by a Tennessee Valley Authority ("TVA") working group to evaluate the value of solar and the determination that six "value streams" should be included (generation deferral, avoided energy, environmental, transmission, distribution and losses) as these are currently quantifiable value streams that impact TVA.[36] The first three items are estimated within TVA's Integrated Resource Planning process[37], transmission was valued based on point to point service rates[38], distribution was estimated at zero[39] and losses were considered at both the transmission and distribution levels[40].

Q. Please provide a review of Grand Canyon State Electric Cooperative Association ("GCSECA") witness David W. Hedrick direct testimony.

A. GCSECA witness Hedrick highlights the position of cooperatives including those that purchase energy and capacity from entities such as Arizona Electric Power Cooperative, which contracts do not provide for a capacity cost reduction opportunity due to DG.[41] He also explores the impact of DG on the distribution system and argues that costs are not reduced and that additional equipment may be needed.[42] He highlights that rates are set based on expenses that are known, measureable and continuing.[43]

[36] Stirling Direct 5:11 and 6:8
[37] Stirling Direct 6:24
[38] Stirling Direct 8:7
[39] Stirling Direct 8:18
[40] Stirling Direct 9:20
[41] Hedrick Direct 10:15
[42] Hedrick Direct 11:8
[43] Hedrick Direct 13:11

Staff notes GCSECA's cooperative distribution utilities have a different cost structure that must be given due recognition. Also, GCSECA also advocates, as Staff does for the inclusion of expenses that are known, measureable and continuing, the present ratemaking formula.

Q. Please provide a review of Residential Utility Consumer Office ("RUCO") witness Lon Huber's direct testimony.

A. RUCO witness Huber highlights RUCO's focus on the 97 percent of residential customers that are non-solar and the costs to serve DG customers that are paid by non-DG customers.[44] He highlights "Value should be a consideration but the amount one pays should be as cost based as possible."[45] "Additionally, RUCO believes that nearly all of the benefits that DG solar could provide to utility customers can also be provided by utility-scale or community-scale solar."[46] He asserts that DG solar is less accessible to customers in contrast to energy efficiency ("EE")[47], that EE offers more diverse grid impacts[48], that PV systems mask but do not reduce a customer's load[49], solar can increase utility system costs[50] and the benefits are concentrated among a smaller group of customers compared to EE[51]. All of these items suggest (to RUCO) that impacts should be evaluated from the perspective of non-DG customers.[52] He asserts that a twenty-year horizon be used and only easily quantified costs and benefits be included.[53] Further, lost revenue and intermittency (resulting in potential additional operating reserves) should be determined.[54] Benefits of solar are considered to include fuel cost savings[55], deferred capacity costs based on coincidence with peak demand

[44] Huber Direct 1:13
[45] Huber Direct 2:17
[46] Huber Direct 4:2
[47] Huber Direct 10:22
[48] Huber Direct 11:7
[49] Huber Direct 11:18
[50] Huber Direct 12:1
[51] Huber Direct 12:10
[52] Huber Direct 12:19
[53] Huber Direct 13:7
[54] Huber Direct 14:2
[55] Huber Direct 18:19

using Effective Load Carrying Capability ("ELCC")[56] and the impact of solar penetration[57]. He estimates that DG could "possibly" result in changes in distribution and transmission capacity needs.[58] RUCO asserts "Generally speaking, community and utility scale solar located within the distribution system have been shown to be more cost-effective (lower $/MW) than DG solar."[59]

Q. Please provide a review of The Alliance for Solar Choice ("TASC") witness B. Thomas Beach's direct testimony.

A. TASC witness Beach argues "DG located behind the meter will both reduce demand for power from the utility, and, at times, will supply power to the utility."[60] "… a DG system appears no different than if the customer had installed a more efficient air conditioner or simply decided to reduce his power usage in the middle of the day."[61] He argues that benefits and costs should be analyzed from multiple perspectives of the utility system, participating NEW customers, and other ratepayers – so the regulator can balance all those important interests."[62], use a broader set of benefits and costs including transmission and distribution capacity and losses[63], calculate the benefits and costs over a 20 to 30 year lifetime (corresponding to a DG system)[64] and focus on exports[65]. TASC highlights "avoided cost savings" and includes avoided energy (and losses), avoided generating capacity (and losses), suggests that marginal line losses are double the system average, avoided ancillary services, avoided T&D capacity (location specific), avoided environmental costs (can be included in avoided energy costs), avoided carbon emissions, fuel hedge (forward cost plus hedging

[56] Huber Direct 17:9
[57] Huber Direct 18:1
[58] Huber Direct 19:1 and 19:11
[59] Huber Direct 23:15
[60] Beach Direct 10:21
[61] Beach Direct 12:26
[62] Beach Direct 17:20
[63] Beach Direct 17:29
[64] Beach Direct 18:12
[65] Beach Direct 18:22

costs), market price mitigation, avoided renewables (avoided utility owned or contracted, societal benefits (climate change damages, scarce water resources, lower air emissions, fewer power outages, greater local economic activity), less costs for integration, administrative and interconnection and possibly lost revenues.[66] He argues that all of the categories are quantifiable and the quantification may require data and/or calculations that utilities may not produce today in the normal course of business.[67] TASC focuses on "… DG will remain a viable economic proposition for participating ratepayers.[68] TASC highlights that rooftop or other renewable distributed energy technologies provide greater choice and new capital, new competition, grid services (if smart inverters are employed), enhanced reliability and resiliency (when paired with storage), high tech synergies, customer engagement and self-reliance, but recognizes that these benefits of choice are "difficult to express in dollar terms".[69]

Q. Please provide a review of Tucson Electric Power ("TEP") witness Carmine Tilghman's direct testimony.

A. TEP witness Tilghman highlights "… the Company believes that it is no longer appropriate to pay full retail credit for DG solar when a utility-scale solar facility on the same distribution system can be built or purchased for approximately half the cost and that provides the same green energy with the same environmental attributes."[70] He poses a significant question relating to solar panel orientation "A western facing panel provides greater production during summer peaking hours, but at an economic impact to the customer based on current rates and NEM policies. The Commission must determine whose value they're going to consider – the individual customer who purchased the system, the utility looking to reduce their overall system cost, or society in general who wants to lower rate impacts with increasing renewable

[66] Beach Direct 20-21 Table 2
[67] Beach Direct 22:1
[68] Beach Direct 25:6
[69] Beach Direct 31:1
[70] Tilghman Direct 4:13

energy?"[71] He replaces the concept of intermittency with a requirement for appropriate values and costs including demand rates and ancillary charges.[72] Coincidence between the utilities annual system peak and DG solar is approximately 30 percent, but solar production is effectively zero two hours after the peak when the utility load is still 90-93 percent of the system peak.[73] He asserts that bi-directional flow on the distribution system will require modifications and upgrades.[74] Tilghman raises the questions as to whether providing compensation for societal benefits, secondary economic impacts and other subjective benefits, if the Commission determines some value for them, should be compensated through utility rate design or by state or local government.[75] He highlights that with increasing penetration of solar systems the utility must take into consideration the right combination of resources to respond to the daily timing (compared to load) along with variability and intermittency.[76] He acknowledges the potential for transmission capacity deferral but notes that a long-term peak shift may reduce this with increased solar penetration.[77] He also recognizes the potential for distribution capacity deferrals.[78] He raises an interesting question relating to the value the utility grid provides to DG solar by providing a sink or storage for excess production and asks whether the utility should be compensated for this value based on the cost of storage.[79] He acknowledges that water savings exist and are included in the avoided energy cost.[80]

Staff agrees with TEP that the values and costs of solar can be benchmarked with utility-scale and community-scale solar, that there may be a deferral value for transmission and

[71] Tilghman Direct 11:14
[72] Tilghman Direct 13:7
[73] Tilghman Direct 14:10
[74] Tilghman Direct 16:4
[75] Tilghman Direct 17:20
[76] Tilghman Direct 20:7
[77] Tilghman Direct 21:1
[78] Tilghman Direct 22:1
[79] Tilghman Direct 23:16
[80] Tilghman Direct 24:4

distribution at certain geographic locations, that water costs are included in the avoided energy cost and raises the question of quasi-storage due to banking that Staff has recommended should be considered for elimination from net metering depending on circumstances[81].

Q. Please provide a review of TEP witness H. Edwin Overcast's direct testimony.

A. TEP witness Overcast argues "With regard to solar DG the proliferation of rooftop solar is not the least cost alternative to acquiring renewable energy resources or even solar DG as the cost of solar is subject to economies of scale just as utility cost benefit from scale economies."[82] He characterizes a rate case as a near term analysis and an IRP analysis as long term.[83] He argues that long term energy forecasts should not be used and levelized but rather based on the short term marginal costs and that the capacity avoided costs are by their nature long-term costs.[84] He suggests that avoided capacity costs be established by the vintage of the installation and also by a market process such as competitive bidding.[85] He asserts that energy payments based on short run costs is the exact same way that utility generation recovers energy costs and that there is no economic reason that solar DG should be any different than a competitive power plant that bears the fuel cost risk in the short term.[86]

Q. Please provide a review of Vote Solar ("VS") witness Kurt Volkmann's direct testimony.

A. VS witness Volkmann suggests that DG can add significant value by deferring capital investment[87] and can have zero costs or require additional measures to accommodate the

[81] Solganick Direct 18:9
[82] Overcast Direct 8:19
[83] Overcast Direct 44:16
[84] Overcast Direct 45:1
[85] Overcast Direct 46:4
[86] Overcast Direct 47:2
[87] Volkmann Direct 6:3

increased load on a feeder[88]. He suggests that utilities disclose the capabilities of feeders to accept DG in order to reduce costs and enable providers to offer innovative alternatives to traditional utility solutions.[89] He recommends the Commission adopt a smart inverter requirement for DG solar and storage installations and opines that this will be an additional input into the DG solar valuation methodology.[90] He discusses the coincidence of DG solar and utility residential and commercial local peaks and suggests that storage may improve the coincidence with local peaks.[91] He recommends that the Commission adopt a detailed marginal cost of service methodology for valuing both transmission and distribution capacity, which he recognizes as data-intensive. He also suggests that where DG makes small, incremental contributions to increase transmission capacity in areas where no immediate capacity upgrade is planned, that this relief has value and should be recognized.[92] He suggests similar treatment for distribution capacity.[93] He provides information on water usage and references a 2011 WRA report and computes the water value for APS as $0.00018 per kWh and for TEP at $0.00028 per kWh.[94] He suggests imputing reductions in service interruptions or reduced duration if the DG can operate without the grid.[95] He suggests that distribution planning processes consider the impact of DG as coordinated alternatives.[96]

VS's proposal to require advanced inverters should be considered by the Commission. Staff has provided additional information about water consumption at generating plants and VS has contributed to this discussion with additional information. Staff suggests that rather than requiring utilities to disclose the capabilities of all feeders that Staff's suggestion that utilities

[88] Volkmann Direct 6:10
[89] Volkmann Direct 7:8
[90] Volkmann Direct 13:3
[91] Volkmann Direct 14:3
[92] Volkmann Direct 18:11
[93] Volkmann Direct 21:4
[94] Volkmann Direct 24:18
[95] Volkmann Direct 26:8
[96] Volkmann Direct 301:12

use an RFP process when feeder capacity is needed would offer a similar result at lower cost.[97] Staff also does not agree that enhanced reliability and resiliency occur with DG solar alone or provide benefits to non-participants.[98]

Q. Please provide a review of VS witness Briana Kobor's direct testimony.

A. VS witness Kobor recommends that the focus be on the energy exported to the utility grid[99], examine cost effectiveness from the perspective of non-participating customers and include impact on utility rates, incorporation of environmental impacts, improved electric reliability, improved system operations and economic development benefits.[100] She recommends focusing on near term levels of DG penetration.[101] She requests funding for third party analysis of a utility's proposal to reform the rate structure and that the results of the DG export valuation be used in the utility's general rate case proceeding to inform DG rate design.[102] She opines that DG valuation must include the full range of long-term benefits and costs and are utility specific.[103] She recognizes that utility ratemaking is based on a one-year test year focused on current utility costs[104] and that environmental and economic development benefits should not be ignored because they do not fit the historical mold of cost-of-service ratemaking[105]. She suggests analyzing all DG solar (residential and commercial/industrial), analyze value over the life of a DG system (20 to 30 years[106]), use an appropriate discount rate (inflation, not WACC[107]); use a near-term forecast of DG penetration (1-3 years[108]) and analyze capacity on a continuous basis (recognize the modularity

[97] Solganick Direct 19:24
[98] Solganick Direct 27:9
[99] Kobor Direct 8:18
[100] Kobor Direct 4:14 and 4:20 and 19:21
[101] Kobor Direct 5:1
[102] Kobor Direct 5:13
[103] Kobor Direct 8:1
[104] Kobor Direct 10:3
[105] Kobor Direct 12:22
[106] Kobor Direct 22:22
[107] Kobor Direct 23:5
[108] Kobor Direct 24:1

of DG additions[109]).[110] She asks for the use of scenarios to address uncertainty of future rate design.[111] She suggests using long-term Energy Information Administration (25 year) fuel projections and sensitivity analyses.[112] She supports the addition of line losses and ELCC for capacity.[113] However, she requests recognition of capacity reserves for utility generation but may imply that similar reserves are not needed for DG solar.[114] She argues that rooftop DG solar requires a robust local workforce that includes installers, manufacturers, sales associates, and distribution workers along with a multiplier analysis.[115]

Staff agrees with VS that the focus is the energy exported to the grid and that the perspective be that of non-participants and line loss and ELCC have a place in the analysis. Staff does not support limiting the longer-term analysis to near term levels of penetration as this induces a mismatch. Staff has concerns about using long-term fuel forecasts due to past performance. Staff suggests that there is a mismatch when rooftop DG solar's economic impact considers labor force while the economic impact of utility generation is not considered within the ratemaking process.

Q. Is there a Commission process in place that provides information to establish the value of DG in a rate case?

A. The major Arizona utilities file biannual Integrated Resource Plans ("IRP"), which detail the generation and transmission options that the utility is and has considered during its process to develop a long-term resource plan. The basis for the long-term resource plan starts with a

---

[109] Kobor Direct 25:1
[110] Kobor Direct 17:13
[111] Kobor Direct 27:11
[112] Kobor Direct 28:5
[113] Kobor Direct 31:6
[114] Kobor Direct 31:21
[115] Kobor Direct 35:5

defined load forecast commonly called the base case. Robust IRP include several sensitivity cases around the base case load forecast to account for variations in the load forecast drivers.

Once a series of load forecasts are developed then the utility can move to capacity planning with the impacts of customer-side effects such as energy efficiency ("EE"), appliance efficiency, demand side management ("DSM") and DG woven into the capacity planning process. In certain cases these "subtractors" may leave the required peak capacity needs static but the capacity planner may consider retirements, fuel conversions and emerging or potential emissions requirements. Generation also has the capability to stand in for some level of transmission and capacity planners consider this function in parallel with supply requirements at specific locations on the grid. Conversely purchases supported by a robust transmission grid can offer alternatives to construction of new capacity.

Q. What issues did Commissioner Forese ask parties to address in this proceeding?

A. Commissioner Forese expressed his concern that the parties may move to positions that are rigid rather than searching for "win-win" scenario. Staff supports the Commissioner's more optimistic viewpoint and notes that its position allows for evolution over time. Although Staff adopted its long-term rate design proposal for Three-Part TOU rates in the on-going UNSE case (15-0142)[116] that position did not call for the immediate suspension of net metering[117] and also supported partial "grandfathering"[118] to recognize that certain customers had been "early adopters" at the urging of many constituencies and thus deserved consideration as the rate design and/or net metering evolved. Further supporting the Commissioner's concern, Staff has recommended that there be an adder to reflect geographic differentials depending on the specific distribution infrastructure if DG can replace or

---

[116] Solganick Direct (15-0142) 10:5

[117] Solganick Direct (15-0142) 45:20 and Broderick Direct (15-0142) 11:9 and Solganick Rebuttal (15-0142) 12:25 and Broderick Rebuttal 8:10

[118] Broderick Rebuttal (15-0142) 5:14 and 6:1, 6:18

significantly delay needed upgrades or expansion.[119] Staff also notes that its Three-Part TOU proposal does not specifically single out any customer subclass including DG.[120] To address the initial post transition impact of Staff's recommended Three-Part TOU rates Staff proposed a 15 percent cost per kW incentive for DG solar installations for the six months after the completion of the full transition.[121] Taken together Staff's proposals in the UNSE case form a foundation suitable for that utility for a win-win approach to the various issues involved.

Q. Commissioner Burns expressed his concerns over the interrelationship of energy and water as it specifically relates to Arizona.

A. Staff recognizes the nexus between energy and water, as many of the existing generation technologies require water as the "working fluid", for power augmentation and also for cooling. Staff witness Zachary Branum has filed rebuttal testimony detailing the use of water for Arizona power generation.

The use of water for the working fluid within Rankine cycle steam power plants (fueled by nuclear, coal or gas) accounts for limited water consumption as the water is recirculated between the boiler and steam condenser and requires limited water blowdown and makeup to maintain the quality of the working fluid. The operating costs for a power plant include the cost of such water usage.

Water can also be used to augment power production in combined cycle or combustion turbine power plants by cooling the inlet air and/or steam injection. This tradeoff of

[119] Solganick Direct 12:1 and 19:24
[120] Solganick Direct (15-0142) 32:11
[121] Broderick Rebuttal (15-0142) 13:20

increased production through increased water usage is included in the operating costs for such power plants.

Water has been historically used as a cooling medium for many power plants, initially in once through cooling and more recently through the use of cooling towers. Power plants have been developed that use air-cooling in place of water-cooling but there can be performance impacts. Staff notes positively that Vote Solar witness Volkmann has raised this issue and has provided some initial information to evaluate the impact of water on power generation. The typical utility IRP would also use these types of evaluation methods to consider the water energy nexus.

The quantification of the amount of water used in various forms of power generation ranging from once through cooling to technologies that do not require water including air cooled units and certain forms of DG (wind, large scale and rooftop solar) is a reasonably accomplished engineering function. What is challenging is the pricing of the cost of the water consumed. The price of water can range from present average costs, recognize the estimated increased future cost of water or consider the use of reclaimed water. Staff supports the use of analyses that include a focus on the cost of water or the value of the avoidance of the use of water.

Q. Commissioner Burns also highlighted the potential advantages of combined heat and power including its use in the agricultural sector.

A. Staff's direct testimony specifically recognizes the potential value of combined heat and power.[122] Staff also has recommended that behind the meter[123] DG be considered in a

---

[122] Solganick Direct (15-0142) 5:12
[123] Solganick Direct (15-0142) 7:7

broader sense than DG solar, as there are many alternatives[124] with various positive attributes[125] that should be considered within the IRP process. The production of energy through the use of agricultural waste can and should be evaluated within the IRP process where such potential opportunities exist in Arizona.

Q. What issues did Commissioner Stump ask parties to address in this proceeding?

A. Commissioner Stump posed many questions for the parties to this docket to address in order to provide a better record for consideration. Staff addresses a number of his questions:

1. The Commission's May 7, 2014 workshop on the Value and Cost of Distributed Generation included debate on whether a remote solar generation station should receive equal treatment with rooftop solar, with regard to calculating the value of solar. What are the parties' thoughts?

- A remote solar generation station (often called utility-scale) is different from rooftop solar due to the economies of scale (usually lower costs) and differential losses between rooftop solar located nearer to load and utility-scale solar located at or near a transmission or distributions substation. At present utility-scale solar could be more easily controlled in response to system (grid) needs, while in the future wide spread use of smart inverters combined with some centralized control may allow rooftop solar to provide similar control capabilities.
- Staff's direct testimony addressed the cost differential between the two types of DG solar and the utility's requirement to procure resources at the lowest reasonable cost.[126]

[124] Solganick Direct (15-0142) 5:10
[125] Solganick Direct (15-0142) 6:5
[126] Solganick Direct 8:4 and 8:14

2. Why argue that a value of solar proceeding is important only for the resource-planning purposes, given that discussions about cost-shifts are informed by discussions on the value of DG.

- While the discussions about cost-shift can be informed by the value of solar, the value of solar should not be used to allow the continuation of cost-shifts. Staff has recommended the mandatory transition to a Three-Part TOU rate design as it properly prices the discrete elements of demand, energy and customer for all customers when fully implemented.[127] Staff also supports that what happens behind the meter is the customer's business and that views all technologies on an equal basis.[128] The purchase of energy from other utilities or a customer should be driven by a reasonable cost standard.[129] If the Commission then determines that DG solar (or any other technology) can add value to Arizona and that value should be compensated through the utility regulatory policy, then that incremental compensation should be identified and separately paid for. Examples might include a distribution adder if substation enhancements can be eliminated that would be paid only to those customers that made the elimination possible.[130]

3. In 2014, lost fixed cost associated with EE programs amounted to $24.1 million out of $34.5 million in total cost shifts. Do recoverable EE lost fixed costs constitute a greater proportion of the total lost fixed cost revenue at hand? Discuss how value-of-solar discussions are informed by comparing the impacts of solar versus EE on the grid. Is the per customer shift larger for solar versus EE customers? Why is the greater customer accessibility of EE programs relevant to this discussion? How does the average DG user's

---

[127] Solganick Direct (15-0142) 30:11
[128] Solganick Direct 7:7
[129] Solganick Direct 8:4
[130] Solganick Direct 19:24 and 22:14

demand curve differ from an EE user, and describe its effect on the grid, given that the EE user is not in need of backup power, unlike the solar DG user.

- The relative magnitude of EE compared to solar DG will change based upon the penetrations of each of these programs and therefore is an evolving situation.
- As Staff has shown in its matrix[131] there are multiple technologies that may provide the attributes of DG solar and DG solar may lack other attributes.
- Staff has recommended the mandatory transition to Three-Part TOU rates[132] to eliminate (after full implementation) the cost shift attributed to DG solar and place all technologies on an equal footing.
- EE and DG solar have different customer accessibility due to financing, orientation, home ownership versus rental property and other requirements. Staff suggests that the inherent value of each (EE or DG) does not affect the other, although the customer should implement lower cost alternatives first.
- Staff suggests that both engineering simulations and load research can demonstrate that EE will reduce both peak demand (coincident and non-coincident) and energy while solar DG will reduce energy consumption and may (or may not) reduce peak demand. Further if DG solar is delivering energy to the grid, flows are reversed (at least through the customer's transformer and potentially into the distribution system).

4. How do we calculate regressive social costs into the value of solar, given that non-solar customers subsidized solar customers?

- Staff has recommended the mandatory transition to Three-Part TOU rates[133] to eliminate (after full implementation) the cost shift attributed to DG solar and place all technologies on an equal footing.

[131] Solganick Direct Exhibit HS-3
[132] Solganick Direct (15-0142) 30:11
[133] Solganick Direct (15-0142) 30:11

7. How will increases in productivity be incentivized once the value of solar is estimated? In addition to the declining cost of panels, is it appropriate to factor relatively high U. S. installation cost into a value on solar determination?

- Productivity increases and/or decreases in inputs such as panels have no direct relationship to the value of solar and do not need to be considered except as a means to estimate market penetration.

8. In value of solar discussions, are we attributing a unique value to DG, which other power sources also have? In other words are there alternatives to DG that may be more efficient in reaching the same desired outcome of reducing carbon dioxide emissions at lower installation costs? How does the cost and value of DG compare with the alternative renewable resources? In pursuing DG, what alternative forms of renewable energy are we displacing? How does the cost and value of DG compare with that utility scale and community scale solar? Is DG as efficient as alternative forms of solar? Is the value of solar lessened for DG versus utility scale or community scale solar?

- As Staff has shown in its matrix[134] there are multiple technologies that may provide the attributes of DG solar and DG solar may lack other attributes.
- The appropriate place to compare the value of different alternatives both renewable and more traditional sources of energy is within the IRP process.
- The relative value of solar as DG, utility or community can be evaluated within the IRP process. Due to economies of scale that are slightly offset by reduced losses it is likely that rooftop DG solar is less efficient than community or utility scale solar.

Q. Does this conclude your direct testimony?

A. Yes, it does.

---

[134] Solganick Direct Exhibit HS-3

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION	)	DOCKET NO. E-00000J-14-0023

REBUTTAL TESTIMONY

OF

ZACHARY BRANUM

UTILITIES ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 7, 2016

TABLE OF CONTENTS

EXECUTIVE SUMMARY
VALUE AND COST OF DISTRIBUTED GENERATION
DOCKET NO. E-00000J-14-0023

Zachary Branum's testimony addresses some of the questions raised by Commissioner Burns' in a letter he submitted on February 8, 2016, regarding a Colorado River shortage and power plant water requirements. Specifically, detail regarding the water consumption requirements of various power plants has been provided. Additionally, the effect of power plant retirement on water consumption has also been discussed. Lastly, a brief explanation of a Colorado River shortage has been given.

After reviewing data provided by Arizona Public Service, Tucson Electric Power, UNS Electric, and Arizona Electric Power Cooperative; it was determined that the largest source of water used in power plant cooling operations is treated effluent (51 percent), followed by ground water (28 percent), and surface water (21 percent). For the years of 2016-2020, it is anticipated that there will be a cumulative annual reduction in ground water and surface water consumption of 26.5 percent and 27.4 percent, respectively. Conversely, annual consumption of treated effluent will increase by roughly 7.2 percent. These changes are mainly due to power plant retirements and conversions, which is reflected in Tables 1 and 2.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Zachary Thomas Branum. I am employed by the Arizona Corporation Commission ("ACC" or "Commission") as a Utilities Division ("Staff") Engineer. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background.

A. I received a Bachelor's degree in Aerospace Engineering (Astronautics) from Arizona State University in 2014 with a specialization in Applied Thermodynamics and Space Systems Design. I will receive my Masters of Science (M.S.) degree in Mechanical Engineering on May 9, 2016 with a specialization in Thermodynamics and Power Generation. Courses included in my graduate study were; Electrical Power Plants, Nuclear Power Engineering, Nuclear Reactor Theory and Design, Renewable Energy Engineering, Solar Thermal Engineering, Solar Commercialization, and Advanced Thermodynamics. Before joining the Commission in January 2016, I spent time conducting research at the National Energy Technology Laboratory for a period of three months, and I instructed undergraduate students at Arizona State University as a Graduate Teaching Assistant.

Q. Briefly describe your responsibilities as a Utilities Division Engineer.

A. In my capacity as a Utilities Division Engineer, I have been assigned to perform engineering analysis and provide recommendations to the Commission on assigned cases. This is my first proceeding as a Utilities Engineer with the Commission.

Q. Did you file Direct Testimony in this proceeding?

A. No.

PURPOSE OF TESTIMONY

Q. What is the scope of your testimony in this case?

A. The purpose of my testimony is to answer some of the questions raised by Commissioner Burns in his letter dated February 8, 2016, regarding the water-energy nexus.

Q. Which questions will you be addressing?

A. My testimony addresses the following:

1. Which power plants in the state of Arizona use surface[1] or ground water for the purposes of cooling?
2. Which power plants in the state of Arizona use treated effluent for the purposes of cooling?
3. What are the water requirements of power plants that are included in previous and future Integrated Resource Plans (IRP)?
4. Which power plants are retiring and how does that affect water consumption?
5. What is the situation with curtailing water in response to a Colorado River shortage?

Q. What resources were used to address these questions?

A. Staff requested power plant water consumption data from Arizona Public Service (APS), Tucson Electric Power (TEP), UNS Electric (UNSE), and Arizona Electric Power Cooperative (AEPCO). In the data requests, Staff also requested responses to questions concerning a Colorado River shortage. Staff also utilized information from the website of the Arizona Department of Water Resources ("ADWR") to address the issue of a Colorado River shortage.

---

[1] Surface water refers to water provided by the Colorado River to the Central Arizona Project, along with other Rivers and lakes.

Q. Why was data only requested from APS, TEP, UNSE, and AEPCO?

A. The data was requested from APS, TEP, UNSE, and AEPCO because each are Load Serving Entities (LSE's), producing and supplying power. Other utilities and cooperatives purchase power from LSE's. Staff believes the power plant data from APS, TEP, UNSE, and AEPCO provides enough information to initially address the questions asked by Commissioner Burns. SRP is the only significant LSE that has been omitted.

CONCLUSIONS

Q. Which power plants of these LSE's use surface water for the purposes of cooling?

A. Four Corners[2], Sundance, Yucca, Navajo, and San Juan[3].

Q. Which rivers and/or lakes provide this surface water?

A. Four Corners Power Plant draws water from Morgan Lake, which receives water from the San Juan River. Prior to 2011, the Sundance Power Plant relied upon Colorado River Water. However, APS entered into an agreement with the Gila River Indian Community in 2011 that allows APS to receive GRIC CAP Indian Priority water, a high priority, low risk supply. Prior to 2015, the water supply to the Yucca Power Plant was drawn from the Colorado River. Yucca now uses groundwater for plant operations. Navajo Generating Station draws water for plant operations from Lake Powell. San Juan Generating Station draws water for plant operations from the San Juan River.

---

[2] Four Corners Generating Station is located in Fruitland, New Mexico. APS owns Units 1, 2, and 3 (now shutdown) and operates Units 4 and 5.

[3] San Juan Generating Station is located in Farmington, New Mexico. TEP owns 50% interests in Units 1 and 2.

Q. Which power plants in the state of Arizona use ground water for the purposes of cooling?

A. Ocotillo, Red Hawk, Saguaro, West Phoenix, Cholla, Springerville, Sundt, Luna, Gila River, Black Mountain, Valencia, and Apache.

Q. Which power plants in the state of Arizona use treated effluent for the purposes of cooling?

A. Palo Verde[4] and Red Hawk. The source of effluent is the City of Tolleson.

Q. What are the water requirements of power plants serving these LSEs?

A. Table 1 lists the water consumptions requirements by source for each power plant for the year 2015. The table also provides the average yearly water consumption based on yearly data ranging from 2006 – 2015.

[4] Palo Verde and Red Hawk use a small amount of groundwater as indicated in Table 1.

	2015 Ground Water Consumed (Acre Feet)	Average Yearly Groundwater consumption (Acre Feet)	2015 Surface Water Consumed (Acre Feet)	Average Yearly Surface Water Consumption (Acre Feet)	2015 Effluent Consumed (Acre Feet)	Average Yearly Effluent Consumption (Acre Feet)
Four Corners	0	0	17,615	22,685	0	0
Ocotillo	353	382	0	0	0	0
Palo Verde	1,913	2,120	0	0	71,914	68,422
Red Hawk	346	248	0	0	3,470	3,486
Sundance	0	0	52	116	0	0
Saguaro	29	211	0	0	0	0
West Phoenix	2,184	2,403	0	0	0	0
Yucca	317	32	322	590	0	0
Cholla	13,009	15,253	0	0	0	0
Navajo	0	0	1,862	1,897	0	0
San Juan	0	0	4,621	4,408	0	0
Springerville	7,321	9,767	0	0	0	0
Sundt	1,346	1,849	0	0	0	0
Luna	440	672	0	0	56	98
Gila River	1,714	1,714	0	0	0	0
Black Mountain	7	29	0	0	0	0
Valencia	5	6	0	0	0	0
Apache	3,244	4,786	0	0	0	0
Total	**32,229**	**39,472**	**24,472**	**29,696**	**75,440**	**72,006**

Table 1: Water Consumption Requirements by Source[5].

On average; 72,006 acre-feet of treated effluent is consumed each year, 39,472 acre-feet of ground water is consumed each year, and 29,697 acre-feet of surface water is consumed each year (seen in Figure below). The largest source of water used in power plant operations is treated effluent, the second largest source is ground water, and the third is surface water. In fact, effluent makes up 51 percent of the total water usage while ground water represents 28 percent and surface water represents 21 percent.

[5] For power plants that serve AEPCO and APS, the water consumption requirements represent the entire water consumed by each plant, regardless of whether the plant is jointly owned. For power plants that serve TEP and UNSE, the water consumption requirements only represent the shares owned by each LSE.

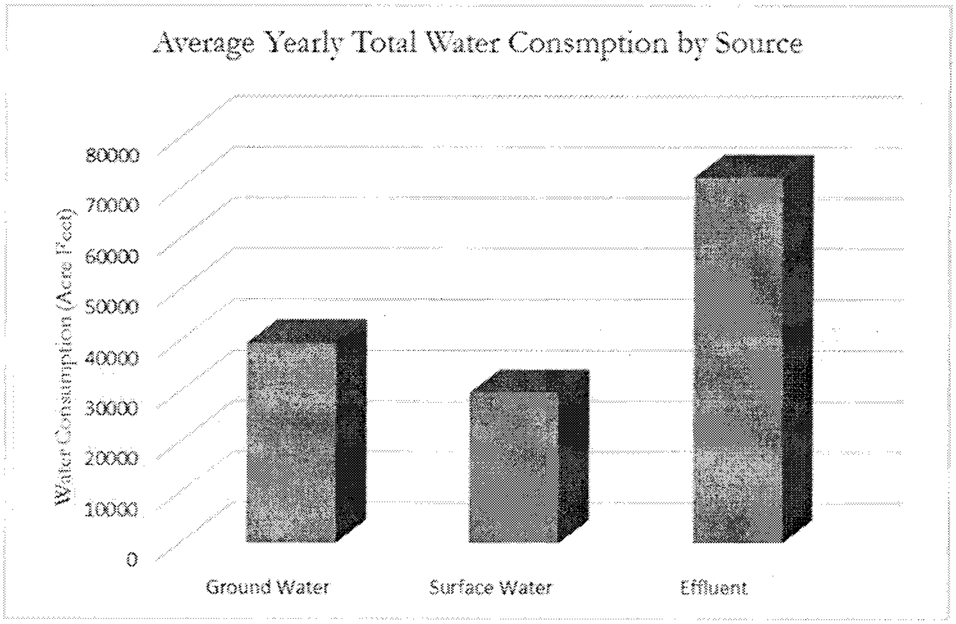

Figure 1: Average Yearly Total Water Consumption

Q. What are the future water consumption requirements for each power plant?

A. APS, TEP, UNSE, and AEPCO provided Staff with projected water consumption requirements for each power plant. Table 2 lists the yearly average water consumption from 2006 – 2015, the projected average yearly water consumption requirements for the upcoming years of 2016 – 2020, and the percent difference of the average yearly water consumption requirements.

	Current GW (AF)	Projected GW (AF)	GW Growth (%)	Current SW (AF)	Projected SW (AF)	SW Growth (%)	Current Eff (AF)	Projected Eff (AF)	Eff Growth (%)
Four Corners	0	0	0	22,685	15,883	-30	0	0	0
Ocotillo	382	12	-97	0	0	0	0	0	0
Palo Verde	2,120	2,149	1	0	0	0	68,422	71,631	5
Red Hawk	248	329	32	0	0	0	3,486	5,478	57
Sundance	0	0	0	116	204	77	0	0	0
Saguaro	211	16	-92	0	0	0	0	0	0
West Phoenix	2,403	3,077	28	0	0	0	0	0	0
Yucca	32	323	918	590	0	-100	0	0	0
Cholla	15,253	8,030	-47	0	0	0	0	0	0
Navajo	0	0	0	1,897	2,145	13	0	0	0
San Juan	0	0	0	4,408	3,314	-25	0	0	0
Springerville	9,767	7,967	-18	0	0	0	0	0	0
Sundt	1,849	1,475	-20	0	0	0	0	0	0
Luna	672	700	4	0	0	0	98	99	1
Gila River	1,714	1,732	1	0	0	0	0	0	0
Black Mountain	29	16	-45	0	0	0	0	0	0
Valencia	6	7	10	0	0	0	0	0	0
Apache	4,786	3,200	-33	0	0	0	0	0	0
Total	39,472	29,032	-26	29,696	21,546	-27	72,006	77,209	7

Table 2: Current, Projected, and Percent Difference of Water Consumption.

As seen in Table 2, it is anticipated that there will be a 27 percent reduction in the average yearly consumption of ground water along with a 27 percent reduction in average yearly consumption of surface water. The average yearly consumption of treated effluent will increase by roughly 7 percent. These changes are mainly caused by power plant retirements and conversions.

Q. Which power plants are retiring/converting and how does that affect water consumption?

A. In 2019, one unit at the Navajo Power Plant will cease operation, thereby reducing water demand for the plant. However, this reduction in water consumption is not reflected in the projected yearly data provided to Staff by TEP because the unit that is being shut down is owned by SRP.[6] At the end of 2017, units 2 and 3 at San Juan Generating Station will cease operation, thereby reducing water demand for the plant by one-half. At the end of 2013, units 1-3 at the Four Corners Power Plant ceased operation, thereby reducing water demand for the plant by over one-quarter. The planned retirement of Unit 2 at Cholla Power Plant in 2016 will reduce water demand for the plant by roughly one-half.

Additionally, some coal power plants will be reducing capacity and/or making the conversion to natural gas. The water demand for Springerville Generating Station will be reduced by roughly 20 percent due to a reduction in coal capacity. The elimination of coal on Unit 4 and the conversion to natural gas will reduce the water demand for the Sundt Generating Station by 20 percent. It can be seen from the data that Saguaro's average yearly water consumption has been reduced by 92 percent which is a result of the retirement of two steam units in June 2013. There is a 97 percent reduction in water demand for Ocotillo due to the modernization project of the plant. Two steam units are being removed from the plant while five new combustion turbines will be added by 2018.

It is important to note that the water reductions seen at some power plants are countered with increased consumption at other facilities. This is primarily a result of more natural gas being used in place of the retiring coal units. For example, Redhawk which uses natural gas will see a 32 percent increase in its average annual groundwater consumption and a 57 percent increase in its average yearly effluent consumption. West Phoenix, which also uses natural gas, will see a 28 percent increase in its average yearly ground water consumption and Sundance is anticipated to consume 77 percent more surface water on average per year. However, the net result is a reduction in yearly average water consumption for both ground water and surface water due to the fact that natural gas plants are typically more efficient than

[6] Refer to footnote 5

their coal counterparts. Additionally, as more modern natural gas plants are used to meet load, it is possible that in some instances their cooling systems are superior to those found in the power plants that are retiring. The increased efficiency and improved cooling systems both factor into the overall anticipated reduction in water consumption.

Q. What is the situation with curtailing water in response to a Colorado River shortage?

A. According to the ADWR, "A shortage is an annual reduction in the amount of Colorado River water available to Arizona, Nevada and Mexico and is determined primarily by the volume of water in Lake Mead. If the water falls below an elevation of 1075', a shortage would be declared. A near-term shortage will not impact water supplies for Arizona's cities, towns, industries, mines or tribes using CAP water. It would, however, eliminate Central Arizona Project (CAP) water supplies to the Arizona Water Banking Authority.[7] It would also reduce a portion of the CAP water supply identified for groundwater replenishment, which would impact agricultural users in central Arizona and may cause an increase in CAP water rates. In the face of potential shortage, farmers in central Arizona may choose to offset supply reductions in their CAP supply by using local supplies including pumping groundwater. Arizona has been planning for a potential shortage for decades. Since 1996, CAP has worked with the Arizona Water Banking Authority ("AWBA") to store excess CAP water underground to provide back-up supplies for municipal, industrial and Native American water users. More than twice the amount (3.2 million acre-feet, which exceeds a trillion gallons) of the Colorado River water that is delivered to central Arizona annually has been stored to date. CAP, the ADWR and the AWBA have planned to recover and deliver these supplies should the need arise."[8]

---

[7]The Arizona Water Banking Authority was established to increase utilization of the state's Colorado River entitlement and develop long-term storage credits for the state. AWBA stores or "banks" unused Colorado River water to be used in times of shortage. http://www.azwaterbank.gov/

[8] *Colorado River Shortage Impacts on Arizona.* Arizona Department of Water Resources. April 2015

Staff requested a response to the following question from APS, TEP, UNSE, and AEPCO; if a shortage on the Colorado River or Lake Mead is declared, what will be the impact on your existing or planned generation units? The following statements are the responses from each;

APS:

"In the event of a shortage on the Colorado River or Lake Mead, no impact is anticipated on existing or planned generation units operated and owned by APS. Prior to 2015, the water supply to the Yucca Power Plant was identified by the USBR as reliant upon Colorado River water, and subject to curtailment in a declared shortage. APS drilled a new well in 2015 that withdraws groundwater, eliminating this risk. Prior to 2011, the Sundance Power Plant relied upon low priority Colorado River water, subject to curtailment in a declared shortage. APS entered into an agreement with the Gila River Indian Community in 2011 that allows APS to receive GRIC CAP Indian Priority water, a high priority, low risk supply."[9]

TEP:

"To the extent there is any impact to TEP generating units from the declaration of a shortage on the Colorado River or Lake Mead, it would be with respect to Navajo Generating Station, Four Corners Power Plant, and/or San Juan Generating Station as each of these facilities use surface waters that are within the Colorado River drainage area. Navajo Generating Station draws water for plant operations from Lake Powell and holds senior water rights as part of Arizona's Upper Colorado River apportionment. Several years ago the intake for the plant was lowered to within the "dead pool" of Lake Powell. In 2019, one unit at the plant will cease operation, thereby reducing water demand for the plant by one-third. San Juan Generating Station draws water for plant operations from the San Juan River, and also holds senior water rights. In addition to these water rights, a water hazard sharing

[9] APS' response to Staff's data request

agreement with the Jicoria Nation is in place, which can provide for additional water rights in the case of an extreme water shortage. Finally, at the end of 2017, units 2 and 3 at San Juan Generating Station will cease operation, thereby reducing water demand for the plant by one-half. Four Corners Power Plant draws water from Morgan Lake, which receives water from the San Juan River under senior water rights. At the end of 2013, units 1-3 at the plant ceased operation, thereby reducing water demand for the plant by over one-quarter. Based on the senior water rights in place and the decrease in water demand at each of these plants, TEP does not anticipate a significant impact from the declaration of a shortage on the Colorado River or Lake Mead. If there was an impact at one of these plants that resulted in the need to curtail generation, we anticipate that TEP would either have sufficient capacity through other resources within its system, or could find sufficient capacity in the wholesale market, specifically due to the large amount of available merchant generation located around the Palo Verde hub."[10]

UNSE:

"UNS Electric's fossil-fired generating units use groundwater for cooling and other process needs. Therefore, we do not anticipate any impact from the declaration of a shortage on the Colorado River or Lake Mead."[11]

AEPCO:

"The operation of Apache Generating Station is not dependent on Colorado River water supply and thus the water source of AEPCO's existing units would be unaffected in the event of a water shortage on the Colorado River or at Lake Mead. AEPCO and its Distribution Cooperative Members have capacity under contract with the Western Area Power Administration for the delivery of hydroelectric generation which is served via these sources. If a shortage were to be declared upstream of these

[10] TEP's response to Staff's data request
[11] UNSE's response to Staff's data request

facilities, the energy available to AEPCO under these contracts may be curtailed depending on the length and severity of the potential shortage. Under such conditions, AEPCO would procure additional energy via generation or purchases from the electric market to fulfill its energy service obligation to its Members."[12]

Q. What are your initial conclusions after reviewing the utility provided data and their responses?

A. Agriculture is the largest use of water in Arizona, followed by residential use. The least demanding are commercial, industrial, and institutional uses. "In Arizona, approximately 15 percent of the water supply is for commercial, industrial, and institutional uses. This includes water used by commercial buildings, hospitals, schools, golf courses, parks, *power plants*, and other industries."[13] It appears that a Colorado River shortage would affect power plants that use surface water as their source for cooling and the LSEs noted that they have prepared for this. As previously mentioned, the largest source of water used in power plant operations is treated effluent (51 percent), the second largest source is ground water (28 percent), and the third is surface water (21 percent). As a result, it does not appear a shortage would severely affect power plant operations, especially with current water rights agreements in place. In the event of a shortage, several utilities intend to rely upon unspecified wholesale purchases which may or may not depend on surface water as a resource.

[12] APECO's response to Staff's data request
[13] http://www.azwater.gov/azdwr/StatewidePlanning/Conservation2/CommercialIndustrial/default.htm