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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
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COMMISSIONERS
SUSAN BITTER SMITH - Chairman
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TOM FORESE

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN OF THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY (RATE DESIGN AND COST OF SERVICE)**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Thomas M. Broderick, Howard Solganick, Barbara Keene and Eric Van Epps the above docket.

RESPECTFULLY SUBMITTED this 9th day of December 2015.

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Arizona Corporation Commission
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BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	)	DOCKET NO. E-04204A-15-0142

DIRECT

RATE DESIGN TESTIMONY

OF

THOMAS M. BRODERICK

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 9, 2015

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APPENDICES

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

Among its rate design related recommendations, Staff recommends that UNS Electric, Inc.'s ("UNSE" or "Company") residential and small general service class rate designs be modernized in a timely rate migration transition process from a two-part rate (monthly minimum and energy charge) to a three-part tariff (monthly minimum, energy charge and demand charge), including a time-of-use energy kWh rate differentiation. A three-part rate makes significant progress toward addressing essentially all of the issues presented by the difficult transition to new distributed generation ("DG") technologies now underway. Residential and small general service customers should be required to migrate to this new rate, but certain specific and definable vulnerable groups could be exempted.

While Staff appreciates the Company's proposal to rely on a Renewable Credit Rate to compensate customers for excess DG, Staff does not presently endorse the Company's proposal. Staff has a number of concerns it would like the Company to address. Staff notes that Commission Docket No. E-00000J-14-0023, which is designed to examine the value and cost of solar, will provide useful and timely information for the parties to consider in this rate case. Therefore, for the time being, Staff does not propose changes to the existing net metering tariff or waivers of the net metering rules, but Staff may update its position in surrebuttal testimony or later at the hearing in this case.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Thomas M. Broderick. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("Commission") as Director of the Utilities Division ("Staff"). My qualifications are provided in Appendix TMB-1.

Q. What is the subject matter of your testimony?

A. My testimony addresses some of Staff's policy recommendations for the residential and small general service class rate designs for UNS Electric Inc. ("UNSE" or "Company"). It also addresses net metering and the related topic of the value and cost of distributed generation ("DG") for all customer classes. The direct rate design testimony of Staff consultant, Mr. Howard Solganick, provides additional and more specific Staff rate design related recommendations.

STAFF'S RESIDENTIAL & SMALL GENERAL SERVICE RATE DESIGN POLICY RECOMMENDATIONS

Q. Why is it Staff's primary recommendation for UNSE to migrate all of its residential and small general service customers to a new tariff design that includes a demand charge component as soon as a transition can be completed?

A. For a variety of reasons, Staff recommends UNSE undertake a revenue neutral process to migrate all of its residential and small general service customers to a new tariff which includes a demand charge within a three-part tariff with time-of-use energy kWh charge differentiation. A three-part tariff is comprised of a monthly customer charge, a per kilowatt-hour ("kWh") energy charge(s) and per kilowatt ("kW") demand charge(s). Staff believes that a three-part rate structure is more reflective of UNSE's costs of service and the sooner a migration occurs the better for all.

A three-part rate design better informs customers who are considering adopting new technologies, including DG, about the utility bill impact of their technology choices prior to purchase and installation. A three-part rate design makes significant progress toward addressing essentially all of the issues presented by the difficult transition underway to new DG technologies.

UNSE has nearly completed deployment of the necessary metering technology, and the Company recognizes that Staff's rate migration transition's success depends on a customer education plan to ensure as smooth a transition as possible. Staff recommends allowing as few customer exceptions to the migration as possible and only for specifically defined, vulnerable customer groups. Staff requests that parties respond in their rebuttal testimonies regarding the possible reasons for exemptions and the bases for identifying eligibility for exemptions.

Demand charges are not a new concept, but rather are in widespread use today for commercial and industrial customers. A demand charge is a proven successful rate design component which better reflects cost causation than rate designs which rely upon energy charges only to recover utility fixed costs. Metering and communications technology improvements, DG penetration, and recent regulatory issues have made its adoption for residential and small general service customers possible, appropriate, timely, and even necessary.

Q. How does a utility recover fixed costs under a two-part tariff versus a three-part tariff?

A. In a two-part tariff, a utility recovers all of its costs, fixed costs included, in the monthly minimum charge and the energy charge(s). Monthly minimum costs are the minimum additional costs to serve a customer connection and are generally defined narrowly as billing and metering related costs. The energy charge recovers all further variable costs, such as fuel for electric generation, and all remaining fixed costs. Hence, at the level of the individual customer, reduction of energy consumption reduces recovery of fixed costs for the utility from that customer. Whether or not that reduced recovery is a concern for the utility depends on what happens in that time frame with the energy consumption of all other customers. A reduction from one customer can be offset by increased consumption from other customers. However, when there is a reduction in energy consumption in total, especially as compared to the level approved for a utility based on its adjusted test year, an under recovery of fixed costs may occur. It is complicated because even in that situation the utility may be able to recover fixed costs by selling energy to other neighboring utilities or entities.

A three-part tariff, on the other hand, applies a demand charge to the maximum usage for a defined period (e.g., one-hour) for the applicable period (e.g., on-peak). It is not unusual for customers to reduce demand by less than they reduce energy consumption because they may not be able to reduce energy consumption for the entire period that the demand charge applies. By definition, a demand charge is designed to recover a utility's fixed costs even if the utility's infrastructure is used only for the minimum period of time (i.e., one-hour).

Q. What significant problems are associated with the continued use of the existing two-part residential rate design in this timeframe?

A. Rate design is premised upon the assumption that a customer's test year energy consumption serves as a reliable estimate of future use. This is an inherent weakness, especially in the present circumstances wherein more and more customers are adopting DG technology.

A customer who newly adopts DG is likely to consume fewer kWhs than in the test year. Such DG customers avoid paying a significant portion of the utility's fixed costs even though DG customers continue to use the grid. The same can be said of many other customers, such as seasonal customers, customers adopting energy efficiency measures and customers implementing lifestyle changes which reduce energy consumption, without reducing their use of the electricity grid. DG customers are receiving attention now because they are currently exacerbating the rate design's weakness. Whether or not such DG customer behavior is a significant problem for a utility such as UNSE at the aggregate level, depends on many factors including whether or not the utility, for example, can use its infrastructure for other customers to meet customer growth or to make sales to other utilities.

At the aggregate level, UNSE has been experiencing reduced sales as mining loads are reduced, energy efficiency is successful, and their service territory is slow to recover from the economic down-turn. While reduced fixed cost recoveries are re-allocated (i.e., shifted) in subsequent rate cases (or more quickly in the interim by lost fixed cost recovery ("LFCR") mechanisms), there is the potential for other customers to shoulder more of the fixed costs. In response, regulators have been asked to authorize capacity kW charges applicable only to DG customers and based on DG capacity installed on the grid rather than on the remaining intensity of DG customers' grid usage. Such grid charges run the risk of being set too low or too high and, therefore, recovering less than or more than the portion of infrastructure still utilized by DG customers. Quite simply, installed DG capacity kW is not equal to the remaining demand kW intensity of use (although there is a correlation).

Ultimately, this scenario leaves utilities such as UNSE in the position of having to maintain their grids at a time when they are facing additional sources of downward pressure on energy sales, including energy efficiency programs, the pending Clean Power Plan, and a post-recession no-growth or very slow-growth service territory. However, a three-part tariff recovers fixed costs for that portion of the grid that DG customers (and all other customers for that matter) utilize.

The above described consequences are largely unnecessary and avoidable with the timely adoption of a demand kW charge in three-part residential and small general service tariffs.

Q. Can these consequences be eliminated by implementing a 3-part rate design?

A. Yes. A well designed three-part tariff with a kW charge as Staff proposes in the testimony of Mr. Howard Solganick can largely eliminate this problem and its consequences. Utilities can recover their fixed costs for the amount of the grid their customers use and most DG customers will still be able to save on their monthly electric utility bills (though probably not as much as previously without taking further actions).

A demand kW charge, applicable during on-peak hours, will even better recover the fixed costs assigned to residential and small general service customers. It will better assist customers to avoid utility costs, and it will encourage the adoption of additional technologies. A proper three-part rate design can align many stakeholder interests rather than place them into unnecessary and repetitive conflict. It will be important not to create too high of a demand kW charge in the first instance and to move to full cost gradually over two or three rate cases. Also, Staff recommends that demand kW for residential and small general service customers be measured and billed for a period of time not shorter than one hour.

Q. But doesn't UNSE's proposal to require only new DG customers to incur a demand kW charge also largely solve the identified list of problems?

A. It would to some degree, but not to the extent of Staff's proposal. It would be unfair to new DG customers and it would perpetuate existing problems and create a new set of problems with potentially difficult and negative consequences. Staff is proposing a more complete solution. Staff does not agree with UNSE's proposal to treat new DG customers differently from existing DG customers in regard to the availability of tariff(s) offered by their utility. Staff believes the DG concern is an emerging concern for utilities and not yet of such a significant magnitude to warrant a one-off approach. For the most part, a utility's concern relates to future periods from forecasting continued DG penetration at increasing rates.

Furthermore, a demand kW charge applicable only to new DG customers would occur simultaneously with a customer's decision on whether or not to install DG, a major investment decision for customers. Even if customers receive history on their demand kW usage and receive a good explanation of a three-part tariff, customers would not likely have any actual previous experience with a three-part tariff. Customers, therefore, may not know to inquire about other lifestyle changes or other technology choices that are alternatives to or useful additions to DG. Mistakes could be very costly to consumers and are unnecessary. Staff concludes it is best if utility rates are designed to be neutral, agnostic, and unbiased towards the technology and lifestyle choices of customers. Rather, customers should pay for (only) the costs they impose on their utilities. Staff concludes that a three-part tariff can recover the costs of service incurred by the utility, even if a customer class is nonhomogeneous and exhibits a wide range of, for example, load factors. DG customers are most likely formerly high load factor customers that have become low load factor customers.

A one-off tariff regime for new DG threatens to unravel the long-lasting system of subsidies and premiums embedded in existing utility rates. These existing subsidies do not need to be fully threatened as a result of new technology. Once DG customers are singled out for special treatment, it sets a precedent for singling out other customer categories enjoying other subsidies. Residential class customers, seasonal customers, low load factor customers, low energy usage consumers, and rural customers are among those groups who typically receive significant subsidies from other customer groups under existing class cost assignments and two-part tariffs. On the other hand, commercial and industrial customers, year-round residential customers, high load factor customers, higher energy usage consumers, and urban customers, are among those groups of customers often paying subsidies under a two-part tariff. Subsidies for seasonal customers, low load factor customers, and low energy usage consumers would be reduced under a gradual transition to a three-part tariff. It is not necessary at this time to trigger a full re-evaluation and unwinding of the various other subsidies.

Staff believes that new meter technology, internet communications portals, and smart phone applications have made it feasible and much easier for residential customers to understand and accept a three-part tariff than ever before. Staff's proposal will be a big step forward in reflecting cost causation in rates over time without unfairly singling out sub-groups of customers and risking unraveling of all subsidies. If the Commission were to conclude that a migration to a three-part tariff should be voluntary, Staff recommends that it be voluntary for all DG customers as well.

Q. Would DG customers be able to avoid on-peak demand kW charges under a three-part tariff even while consuming less energy kWh?

A. Not unless they can reduce usage for the entire peak period. Under Staff's proposal to apply a kW charge during on-peak hours (e.g., summer weekdays between 2 p.m. to 8 p.m.), DG customers cannot avoid demand kW charges unless they reduce the intensity of their grid usage for the entire on-peak period. (Staff witness Mr. Howard Solganick addresses the time-of-use feature of Staff's proposal.)

Solar DG customers will, therefore, need to carefully consider their lifestyle decisions and additional related technology choices for those hours, for example, in the summer from when the sun starts to set and until 8 p.m. Home pre-cooling, postponing cooking and laundry, battery storage, energy efficiency, smart thermostats, and load controllers are among the additional possible choices residential customers might consider and implement in addition to or in lieu of DG. Under Staff's proposal, residential customers would largely already be familiar with life under a demand kW charge tariff before selecting DG and would be much better informed for making follow-on technology and lifestyle decisions, including DG.

Q. Will Staff's proposal create as many problems as it resolves?

A. No. Staff believes residential customers can be quickly educated and that a transition period as proposed by Mr. Howard Solganick is reasonable. Staff believes there will only be a temporary challenge for residential customers to understand, accept and adapt if the Company develops and implements a customer education program. Staff requests that UNSE define and develop the details for a rate migration transition process and share with the parties in its rebuttal testimony.

Q. Why not raise the monthly customer charge in lieu of a demand kW charge and keep a two-part tariff?

A. Such an increase would be unacceptably large. Staff strongly opposes addressing the described under recovery of utility fixed costs in this manner. Staff believes this would be highly unfair and unpopular to raise significantly the monthly customer charge, especially with residential customers. It would eliminate nearly all customer ability to control or reduce electric bills. It would be highly unfriendly to new technologies and a major step backwards. Staff recommends keeping the monthly customer charge narrowly focused on the cost of a meter, the costs of customer service and billing and the cost of the service line. Staff goes as far as it is willing to go in accepting UNSE's proposal to include distribution costs for a minimum sized system in its monthly minimum charge as discussed by Staff witness Mr. Howard Solganick.

Q. Is Staff requesting vulnerable groups to self-identify?

A. Yes. Staff does not presume that any group is so vulnerable as to be unable to understand and tolerate a demand kW charge. Customer vulnerability is quite different than mere opposition to an anticipated (initial) discomfort with a transition from a two-part to a three-part tariff. Nevertheless, Staff is interested in considering feedback from potentially vulnerable groups. Staff looks forward to input from other participants in this case regarding the reasons for vulnerability (e.g., high kW medical equipment), methods to identify such vulnerable customers, and appropriate alternative pricing. Staff prefers that methods to identify vulnerable customers be precise and not subject to manipulation. Staff prefers vulnerable groups be narrowly and specifically defined so as to not become too large.

Staff witness Mr. Howard Solganick expresses Staff's willingness for the record in this case to remain open for a period following a decision. This process might allow for possible adjustments to eligibility for status as a vulnerable customer.

For completeness, please note that Staff does not believe that *existing* DG customers comprise a vulnerable group. In other words, existing DG customers should participate in the migration to a three-part tariff under Staff's proposal. They are not to be "grandfathered" regarding their utility tariff for their electricity purchases.

Q. If Staff's proposal is adopted, will DG need to remain a component of the LFCR?

A. Only for a while. Staff's proposal is to only rely on the LFCR's DG component for the recovery of eligible costs from the end of the test year until new rates are effective in this case. Once new rates are effective, no new lost fixed costs would be considered in the LFCR's DG component. As residential and small general service customers successfully migrate to a three-part tariff, the need for DG to remain as a component of the LFCR is greatly reduced and eliminated following the full transition. The DG portion of the LFCR can, therefore, be eliminated in the Company's next rate case.

Q. What about subsequently imposing grid reset charges in the interim between rate cases?

A. A three-part tariff also makes this step unnecessary. At this time, Staff is opposed to imposing grid capacity kW reset charges on DG customers either between rate cases or as a result of a rate case. Staff concludes that it is the opposite of sound rate design principles to impose a charge on the amount of demand kW the customer is *removing* from the system; rather, it is wise to impose a kW charge for the amount of a utility's system the DG (or any) customer uses.

STAFF'S NET METERING AND VALUE AND COST OF DISTRIBUTED GENERATION RECOMMENDATIONS

Q. Why does Staff not support the Company's Renewable Credit Rate ("RCR") net metering rider at this time?

A. While Staff appreciates the Company's proposal, Staff has a number of concerns, including those expressed by Staff witness Mr. Howard Solganick, that it would like the Company to address. Staff notes that Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, may provide useful information to the parties in this rate case. Therefore, for the time being, Staff does not propose any changes to the existing net metering tariff or waivers of the net metering rules, but it may update its position in its surrebuttal testimony or later at the hearing in this case. If ultimately the Commission continues to rely upon net metering, the migration to a three-part tariff will not pose any issues as the energy kWh charges in a three-part tariff and on a time-of use basis would be used for net metering.

Q. Is Staff concerned about the frequency of updating the Company proposed RCR?

A. Yes. The frequency of updating as well as the dependence on only one agreement is concerning. The Company's proposal does not consider non-generation functional components either from an avoided cost perspective or from an apples to apples perspective of a resource substitution of utility-scale solar for rooftop solar. Staff also wants to consider further whether it prefers a net avoided cost plus adder method (as is the typical suggested approach in studies valuing solar) or whether it prefers a comparable resource cost method as the Company proposes or whether it depends on the circumstances of each utility.

Q. Does this conclude your direct rate design testimony?

A. Yes.

QUALIFICATIONS

THOMAS M. BRODERICK

Employment History

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Field Team Lead, Power Africa Project, Deloitte Consulting, Nairobi, Kenya (September 2013 - August 2014)

Director, Rates & Regulation, EPCOR and American Water, Phoenix, AZ (2004 - August 2013)

Director, External Affairs, PG&E National Energy Group, Phoenix, AZ (2001 - 2003)

Senior Energy Advisor, USAID, US Embassy, Kiev, Ukraine (1999 – 2000)

Consultant, PG&E Energy Services Corporation, Phoenix, AZ, (1997 – 1998)

Manager / Supervisor, Planning, Forecasts and Regulatory Affairs, APS, Phoenix, AZ (1984 – 1996)

Marketing Research Analyst, Miller Brewing Company, Milwaukee, WI (1982-1984)

Economist, Illinois Health Finance Authority, Chicago, IL (1981-1982)

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BEFORE THE ARIZONA CORPORATION COMMISSION

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BOB STUMP
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TOM FORESE
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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-15-0142

DIRECT

RATE DESIGN TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 9, 2015

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EXHIBITS

EXECUTIVE SUMMARY
UNS ELECTRIC CORPORATION
DOCKET NO. E-04204A-15-0142

Mr. Solganick's direct rate design testimony reviews the UNS Electric, Inc. ("UNSE" or "Company") proposal for cost of service, revenue allocation, rate design, and modifications to the Lost Fixed Cost Recovery mechanism (LFCR").

Mr. Solganick co-presents the Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff") recommendation that the Commission promulgate a long-term plan of rate design for UNSE and its customers. This plan responds to the schedule for installation of advanced metering and the opportunities it affords.

Staff recommends that the long-term rate design should focus on a three-part rate (customer, demand and energy) including time-of-use ("TOU") to better and more accurately relate rates to underlying costs. Staff also proposes the timing of the implementation of this plan and the further efforts that UNSE must take to provide customers with the information they need to respond to the more accurate three-part rate design. UNES should also develop an education program to help customers understand their usage information and how customers can manage their usage and change the size of their bills.

Mr. Solganick evaluates UNSE's Class Cost of Service Study and places its results into perspective and recommends that it be used as a guide to revenue allocation and a source of unit cost data for rate design.

Mr. Solganick provides the Staff recommendation for the allocation among the five major rate classes of Staff's recommended rate increase. This recommendation is tempered by the concept of gradualism due to the changes in rate base and changes in UNSE's recommended cost allocation methodology.

Based on a review of UNSE's application and responses to Staff data requests and consistent with Staff's long-term rate design plan, Mr. Solganick provides recommendations for the rate design for each of UNSE's five rate classes along with Customer Assistance Residential Energy Support ("CARES"), interruptible rates, distributed generation, service fees, the Buy-Through provision, Automated Metering Infrastructure ("AMI") Opt-Out customers and Economic Development proposals of UNSE.

Staff recommends that the Commission accept UNSE's proposal to eliminate the Fixed Charge Option from the LFCR mechanism. Staff recommends that the Commission reject the Company's other LFCR proposals and proposes the elimination of the DG portion of the LFCR in the Company's next rate case.

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, PA 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 testimony relating to the engineering analysis of the UNS Electric, Inc.'s ("UNSE" or "Company") rate base items, service reliability, and planning process on

November 6, 2015. My previous testimony in this case includes a summary of my background, qualifications, and experience.

Q. What is the purpose of your rate design testimony?

A. My testimony provides Staff's long-term plan of rate design for UNSE, analyzes the Company's Class Cost of Service Study ("CCoSS"), recommends an alternate allocation of the revenue increase proposed by Staff, and recommends how the increased revenue should be implemented within the Company's various existing and proposed rates, including a mandatory transition to Three Part-TOU rates for residential and small general service customers. I also present Staff's recommendations to address Customer Assistance Residential Energy Support ("CARES") rates, interruptible rates, distributed generation ("DG"), Service Fee charges, Buy-Through provision, Automated Metering Infrastructure ("AMI") Opt-Out and economic development. Finally, I present Staff's recommendations for the existing Lost Fixed Cost Recovery ("LFCR") mechanism. Some of these topics are also addressed in the direct rate design testimony of Staff witness Thomas M. Broderick.

DIRECT TESTIMONY

Q. Please summarize Staff's positions?

A. Staff recommends:

Long-Term Rate Design Plan

Rates should be based on costs and recognize the concepts of customer, demand and energy including time-of-use ("TOU"). When changes are made gradualism should be recognized. This plan is placed into the context of evolving metering and customer information capabilities.

Class Cost of Service Study

The purposes of a CCoSS are discussed along with the changes in the Company's CCoSS including a new production cost methodology. Staff recommends the use of Average and Excess-NCP, which the Company is proposing.

Revenue Allocation

Staff recommends a revenue allocation among the customer classes based on moving all classes to cost of service but recognizing that gradualism is necessary due to the effects of a new production cost methodology and the Company's inclusion into rate base of a portion of the new Gila River Unit #3.

Rate Design

Staff recommends rate designs for each rate schedule and consistent with the long-term rate design plan recommends the mandatory transition of residential and small general service rates (including DG customers) to Three Part-TOU rates. Staff also highlights areas where the Company should provide further information and justification for its proposals.

Staff highlights that due to the changes proposed the Commission should keep the rate design portion of the case open to resolve unanticipated customer rate impacts.

Miscellaneous Items

- CARES – Staff recommends that the level of this discount not be reduced and that a CARES provision for the new Three Part-TOU rate should be developed.

- Interruptible Rates – Staff recommends that the Company's proposed new interruptible Rider R-12 be adopted and that the existing IPS rate should be eliminated at the end of the Company's next rate case.

- Distributed Generation – Staff notes that Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, may provide useful information to the parties in this rate case. Therefore, for the time being, Staff does not propose any changes to the existing net metering tariff or waivers of the net metering rules but it may update its position in its Surrebuttal testimony or later at the hearing in this case. If ultimately the Commission continues to rely upon net metering, the migration to a three-part tariff will not pose any issues as the energy kWh charges in a three-part tariff and on a time-of-use basis would be used for net metering.

- Service Fee Charges – Staff analyses the Company's proposals and recommends which fees should apply to Opt-Out customers.

- Buy-Through – Staff looks forward to the input of other parties and does not object to this mechanism if there are no adverse impacts and no costs to other customers.

- AMI Opt-Out – Staff recommends that a non-transmitting solid-state meter be used to accumulate information needed for Staff's long-term rate design plan and the transition of Opt-Out customers to the Three Part-TOU rate along with recommended charges for the installation of the meter and monthly meter reading.

- Economic Development – Staff supports the establishment of the program but does not support any request for lost revenues.

LFCR

Based on a review of the Company's application, supporting testimony, and responses to data requests, Staff recommends that the Commission reject the Company's proposed changes to the LFCR mechanism that include:

- Allowing the Company to receive recovery for generation costs;
- Increasing the recovery for distribution demand costs from 50 percent to 100 percent;
- Increasing the cap on recovered costs allowed for each year from 1 percent to 2 percent;
- Expanding the LFCR mechanism to include revenues lost from a "Buy-Through" provision to be established in the Company's tariff; and
- Combining the Energy Efficiency ("EE") and DG portions of the mechanism on the customer's bill.

Based on a review of the Company's application, supporting testimony, and responses to data requests, Staff recommends that the Commission accept the Company's proposed change to the LFCR mechanism to eliminate the Fixed Cost Option.

Staff recommends that the DG portion of the LFCR mechanism:

- Be applied only to lost fixed costs from the end of the Test year to the rate effective date
- Be eliminated in the Company's next rate case.

LONG-TERM RATE DESIGN PLAN

Q. Are significant changes occurring in the Company's capability to measure how and when customers are using energy?

A. Yes. Based upon discussions between Staff and the Company, the Company expects to complete a significant majority (subject to a few geographic limitations) of its installation of AMI by the middle of 2016.[1]

Q. How has electric metering changed over time?

A. Initially there was no metering and infant utilities charged either a flat rate per customer or charged by the number of light bulbs installed by a customer. This pricing methodology is still used for lighting (and other fixed load) customers because the number and wattage of bulbs can be accurately verified and enumerated. By not using meters, the costs of meters and meter reading do not need to be charged to those customers.

With the advent of energy meters at a reasonable cost, coupled with a wider range of lighting and appliances, utilities began to charge customers based upon the energy consumed. This type of rate design did not recognize different costs based upon demand (often expressed as load factor). Two customers using identical amounts of energy but with different usage patterns could have different levels of demand and require different amounts of generation, transmission and distribution equipment (at very different costs), and therefore one customer may be undercharged and the other overcharged if demand was not measured and taken into

[1] UNSE Response to STF 2.022

account. Alternatively, two customers who require the same equipment might use very different amounts of energy and again would result in one customer being undercharged and the other overcharged.

The introduction of demand meters, which measure peak demand usage within the billing period along with energy consumed, allowed for the introduction of rate forms such as the three-part rate (customer, demand and energy) or a variant (hours of use). The use of the demand meter and associated rates reduced the disparate impact of energy-only rates. Demand meters have generally not been used for residential customers due to the cost of the more complex meter, and the increased complexity of billing and the information that should be provided to the customer. The residential class was often seen as homogenous enough not to have wide usage disparities and therefore the cost of demand meters and their associated rate complexity was not justified.

For a number of years utilities have been able to measure the consumption of energy over very narrow time periods (hourly or even 15 minute intervals) but the challenge has been recording that data cost effectively and then providing that data to customers so that the customer could decide whether and how to respond and change their usage (energy) or usage pattern (demand). Interval data has been used for load research to provide an understanding of how different customers use energy and the data were typically recorded on magnetic tape and analyzed in bulk. While interval data were suitable for load research purposes, it was difficult to provide the data to a large number of customers at a reasonable cost.

Similarly, time-of-use meters could accumulate energy usage in a few time-differentiated periods but these data were only recorded and reported as On-Peak, Shoulder and Off-Peak and did not offer much information to the customer, such as when the energy was used on an interval basis.

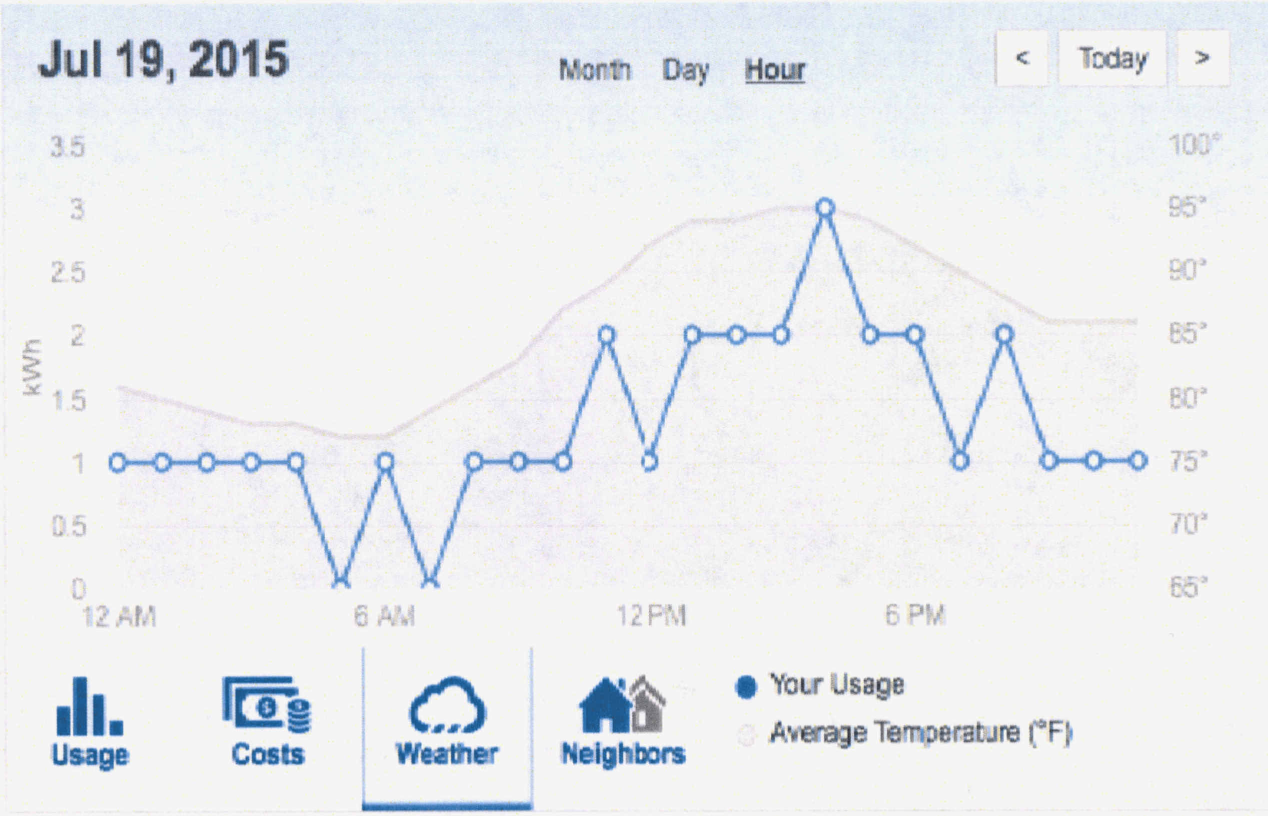
AMI has benefited from the declining costs of electronic versus mechanical metering devices and the ability to analyze data on a customer-specific basis. Utilities that have installed AMI often develop meter data management systems that allow for the extraction of energy and demand data for billing purposes. Unfortunately, some AMI planning does not go far enough and some utilities cannot provide individual customers their usage information in a form that supports customers' decisions about how and when to use energy more effectively and efficiently.

Q. Can you provide an example of conveying energy information to customers?

A. As a residential customer, my electric utility provides me with access to a portal where I can view my energy consumption.

On a macro basis, I can view my monthly consumption and compare it to an aggregate grouping of my neighbors and to a more limited aggregate grouping of my most efficient neighbors. The aggregate nature of these data protects my neighbors' privacy, and the portal limits my neighbors' access to my data, protecting my privacy. Various entities have opined that providing this "new" data encourages some customers into becoming more efficient in their use of energy.

My utility also provides me (with a two-day delay) my hourly energy consumption, which is equivalent to hourly demand. From this timely information, I can determine the peak period(s) of energy usage and then decide if I wish to change my energy usage in the future.



Q. How did the confluence of new metering and information capabilities, changing customer characteristics and the Company's proposals in this case initiate a discussion with Staff?

A. At this point in time, many utilities have the capability to record interval data as a result of the installation of AMI. Some utilities can provide that data to individual customers in a form that is somewhat easily understood, although some customer education is necessary. Residential customers are increasingly becoming non-homogenous as they adopt various forms of heat and distributed generation and as their lifestyles, demographics, and work patterns become increasingly more diverse.

Staff has raised the concept of offering a "plan" of how rate design should evolve so that the parties to this case could provide their input and the Commission could consider a plan in order to provide the Company's customers advance notice that changes are underway. As we considered potential positions in this case, the wisdom of Staff's suggestion became clear as it may assist customers as they make their individual long-term energy decisions.

Q. Please articulate the Staff's long-term rate design "plan".

A. There are a number of principles within this plan.

Rates should be based on costs derived from class cost of service studies not only at the class level but also to illuminate the unit costs of individual customer, demand and energy rates. Marginal costs should be given some consideration but embedded costs are the focus. There should be a place for test programs to determine if rate design can alter the need for capital investment and/or energy costs. When changes occur, gradualism should be used to temper the short-term impact until the next rate case.

Rate design should recognize the concepts of customer, demand and energy, and also recognize TOU and seasonality ("Three Part–TOU"). The number of rates available to customers should be minimized to avoid confusion as Three Part–TOU rates allow for cost-based billing of non-homogenous customers within one rate schedule. Inverted rates would be supplanted by the seasonal TOU component and the demand component which recognize load factor.

Generation pricing would reflect the marketplace by considering seasonality, TOU, hourly pricing and demand response.

Rates should be supported by customer-specific usage information collected under extreme privacy and security, but available to customers along with tools to help them see the impact and make decisions. In the long-term, customers might receive cost "warning" using a simple red/yellow/green indication in their home or business and, for example, their demand controllers could access detailed price information online.

Rate subsidies, as determined appropriate, should be clearly delineated, be based on and computed from standard rates. For example, a CARES customer would be billed as a standard residential customer including all trackers and adjustment clauses but also receive a specific discount amount. Should a CARES customer's situation change for the better, the only change would be the removal of the CARES discount, which would be easily recognized by that customer. Hence, Staff's plan migrates CARES eligible customers to the Three Part-TOU rate.

The Commission's Docket No. E-00000J-14-0023 will assist Staff and the parties to determine an adequate methodology and quantification of compensation to potentially replace net metering. Ultimately if DG results in savings across the utility system and differentially for specific geographic areas (feeder), these effects would in time be separately identified.

Q. Does migrating all customers of a class onto a single Three Part-TOU rate limit a customer's choice to one alternative?

A. Customers have very limited options now. The two-part rate allows the customer to increase or decrease his/her energy consumption to change the total bill. A two-part rate with TOU allows the customer to increase or decrease his/her energy consumption and when that energy is consumed but does not reflect the intensity or magnitude of use. The Three Part-TOU rate allows for a third dimension that the customer can use to affect the intensity of use.

One customer may come home from work, turn on the air conditioner, shower using hot water from an electric water heater and start the clothes washer all at the same time. A second customer may decide to linger with friends and have dinner out but have the air conditioner begin to cool the home before arrival, shower later in the evening and set the clothes washer to start at 4 AM. The intensity of multiple electric appliances operating together places a greater load on the system than the load of a single appliance. The Three Part-TOU rate prices the consumption and usage pattern differently by charging for both the demand (intensity) and energy consumed separately. In each case, the customers can choose the usage and pattern they wish and be charged appropriately for raising or lowering the utility's costs.

Q. Can you try another analogy?

A. Yes. A rental car customer decides what size car to rent. Larger or more expensive cars cost more per day, whether the car is driven or not. When driven, the renter pays for the gas. Rental car pricing may also be different on weekdays compared to weekends. The size of the car is similar to demand, the miles driven (gas purchased) is similar to energy, and the weekday/weekend similar to TOU. If one renter chooses a small car for weekday errands and another for a long weekend trip for a family of six, the final charges will be different.

Q. What would be the long-term impact of this rate design "plan"?

A. Customers would have greater information available to make their own energy decisions, and rates would more accurately price those decisions and lessen the consequential impact on other customers. Over time, customer and demand charges would gradually increase and energy charges would become "purer" and lower for the distribution component. A customer could reduce costs by adjusting demand and/or by changing energy usage. The customer benefits from tools and education to take the best advantage of new rate forms.

As the Three Part-TOU rate design becomes fully implemented, the magnitude of the LFCR will diminish and can be eliminated for DG, as it is a "fix" for rates that focus too highly on energy.

Q. Are these concepts new or new to the Company?

A. For medium and large customers demand rates have been the norm and a Three Part-TOU rate is available. Flat rates are still appropriate for fixed, predictable loads such as lighting, cable amplifiers and traffic signals.

In the previous UNSE rate case (Docket No. E-04204A-12-0504), I raised a number of these concepts but did not articulate them as a plan. Similarly, in this case the Company has raised some of these concepts but has not provided the data and education components critical for customer understanding of the Three Part-TOU rate design.

Q. What are the important transition principles for the move towards the long-term rate design plan?

A. Rate design should not be changed until customers have private, secure, easy, timely and comprehensible access to their usage data. Staff recommends that the Company develop and submit a detailed transition plan for Residential and Small General Service customers in its rebuttal.

As with most any mandatory transfers from old rate designs, the initial transfers should be done in phases. Customers with the opportunity to change their usage or usage patterns should be transferred first. This will generally imply that larger users within a class or rate who have many appliances and/or uses for energy and therefore have multiple opportunities to change the appliance stock and usage pattern would be transferred first. Customers who might have only lighting and refrigeration (low use) might be transferred last. Transferring customers in phases allows for testing of education and information transfer and is best tested with smaller customer classes first.

Q. What other actions might be needed during the transition?

A. The Commission should keep the rate case open beyond its revenue requirements decision to monitor the transition and deal with unknown problems if they occur. This period should last at least six months past any required transition period or a minimum of 18 months. The Commission has done this with prior cases[2]; however, I am not opining on the legal methodology to accomplish that.

The utility should monitor revenue by rate schedule and report (revenue and customer impacts) quarterly to Staff and changes in revenue should be analyzed on an annual basis.

The transfer from a two-part to a three-part rate may adversely affect certain customers. For example, school athletic field lighting that is separately metered (not as part of a school building complex) and uses energy a few times a year may see a significant impact on that particular bill. The Commission may wish to consider the impact of the rate design change on the total electric bills of the school or district and, if needed, institute a transitional "rate stopper" to limit the impact on the customer. The impact should be evaluated over at least a one-year period on the customer's total bills, not on a single bill or account basis. The impact should be balanced against the costs that the utility incurred when the school district decided to not connect the field into its internal wiring system (to save the district a capital expenditure). The Company can assist by identifying potentially affected customers. Staff

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[2] ACC Decision No. 73912 page 73

witness Thomas M. Broderick provides more details about potential "vulnerable" customers in his testimony.

CLASS COST OF SERVICE STUDY

Q. What is the purpose of a fully allocated cost of service study?

A. Just as the rate case revenue requirements process studies each element of the Company's operations to determine the overall cost to operate the Company efficiently and effectively, a fully allocated cost of service study attempts to determine the individual cost to serve each customer class and subclass. A fully allocated cost of service study is intended to assist the Commission to allocate revenue requirements among customer classes.

Q. How can a regulator use the cost of service study?

A. Because customer classes use the utility's system on an interrelated or shared basis, regulators have historically used a fully allocated cost of service study as a guideline to allocate revenue among classes. Regulators typically also consider economic, social, historical and other factors that may affect customers when determining revenue allocation. Such considerations often result in rates that deviate from strict cost of service.

Q. Are there limitations to a cost of service study?

A. Yes. A cost of service study involves judgment and decisions on the part of the practitioner in assigning costs to the various customer classes. In some situations, decisions are made to use a particular allocation factor for a particular account. In other situations, data used to develop an allocation factor are not always complete and/or timely and the practitioner must deal with the resulting uncertainty. Consequently, the cost of service study acts as a guide in revenue allocation and in formulating rate design.

Q. Has the Company provided a class cost of service study?

A. Yes. The Company provided its CCoSS based on the Test Year (twelve month period ended December 31, 2014).[3] Schedule G provides the individual class returns for the Company's five major service classes (Residential, Small General Service, Medium/Large General Service, Large Power Service and Lighting).

Q. Have you reviewed the CCoSS presented by the Company?

A. Yes. The CCoSS was provided as Schedules G-1 through 7. I performed a review of the allocations, developed data requests and reviewed the answers to Staff and other parties. I conducted informal technical conferences with the Company to understand certain aspects of the CCoSS.

Q. Did the Company adjust or normalize its revenues?

A. Yes. The Company used a Test Year (twelve months ending December 31, 2014) and then adjusted it to reflect more normal or appropriate (from the Company's viewpoint) conditions.[4]

Q. Has the CCoSS changed from the prior rate case (Docket No. E-04204A-12-0504)?

A. Yes. The prior CCoSS had six service classes (Residential, Small General Service, Large General Service, Large Power Service, Mining and Lighting). The Residential, Small General Service and Lighting classes are similar. The Company created new rate schedules for Medium General Service ("MGS") and Large Power Service ("LPS") based on demand and voltage criteria from the former Large General Service ("LGS") and Large Power Service rate schedules.[5]

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[3] UNSE Filing Schedule G
[4] UNSE Filing Schedule G-1 lines 41 and 44; Schedule G-2 lines 39 and 42
[5] Jones Direct 44:4 and 44:12

Q. Are the changes to the service classes appropriate?

A. Yes. The differentiation by demand and voltage proposed by the Company is appropriate. The combination within this case's CCoSS of Medium General Service and Large General Service classes should be disaggregated in the Company's next CCoSS as the transition to the MGS rate schedule will have been completed.

Q. Have the Company's capacity resources changed since the last case?

A. Yes. The Company recently purchased a 25 percent share of the Gila River Power Plant Unit #3 combined cycle generating plant in concert with its affiliate Tucson Electric Power ("TEP").[6]

Q. Please describe the attributes of a typical combined cycle generating unit?

A. A combined cycle generating unit is flexible in that it can start and stop operations (dispatch) easier than a coal or nuclear plant and is generally more thermally efficient than most other forms of fossil and nuclear generation. Typically combined cycle plants are fueled by natural gas with distillate oil backup.

Q. What allocators does the Company use for its power supply expenses within the 2014 CCoSS?

A. For Other Production Plant, the Company uses the DPROD allocator, which is classified exclusively as demand.[7] For Other Production Expenses, the Company uses the EFUEL allocator, which is classified exclusively as energy.[8] For Purchased Power Expenses the Company uses the EFUEL allocator for energy charges, which is classified exclusively as energy.[9]

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[6] Hutchens Direct 2:6 and 8:6
[7] UNSE Schedule G-3, Sheet 4, lines 14-20
[8] UNSE Schedule G-4, Sheet 4, line 18
[9] UNSE Schedule G-4, Sheet 4, line 29

Q. What allocator methodology did the Company use for DPROD?

A. The Company states that it used an Average and Excess allocator for production plant and expenses.[10]

Q. Has the Company changed the selection of the DPROD allocator since the last case?

A. Yes. Previously the Company used a Peaks and Average allocator in its 2012 CCoSS.[11]

Q. Is the Company's Average & Excess & 4CP allocator a standard production methodology?

A. Although the Company stated that it is using an Average and Excess allocator[12] it was non-specific in written testimony about the construction of the allocator. However, the Company provided a table within its testimony showing the impact of various allocators on class returns.[13] Within this table, the Company describes its Average and Excess allocator as Average & Excess & 4CP, which, based on the title, would be non-standard. Using coincident peaks (one or more) within the average and excess allocator is not a standard or recommended methodology.

Q. Why do you say that Average & Excess & 4CP does not appear to be a standard methodology?

A. The Electric Utility Cost Allocation Manual indicates:

> "If your objective is – as it should be using this method – to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it

[10] Jones Direct 25:3
[11] Jones Direct 25:3
[12] Jones Direct 25:7
[13] Jones Direct 25:12

> produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands."[14]

Q. Did you explore this concern with the Company?

A. Yes. The Company indicated that the DPROD allocator is a traditional A&E-NCP allocator but is allocating the 4CP value, thus the use of 4CP as an identifier. The Company confirmed this in an email.[15]

Q. What is Staff's recommendation for an appropriate methodology for the DPROD allocator?

A. The appropriate methodology is Average and Excess-NCP (noncoincident peaks) as supported by the National Association of Regulatory Utility Commissioners ("NARUC") Manual as noted above. This allocator reflects both average load (energy) and excess load (demand) without algebraically becoming a CP allocator. This methodology is a better fit to a capacity plan that focuses on both energy and capacity (and selects an efficient and flexible generation technology). Based upon the Company's response, the Company's Average & Excess & 4CP allocator meets Staff's recommendation.

Q. Are there disproportional impacts between the present CCoSS and the prior one?

A. As Exhibit HS-2 shows, the change for the Residential and Small General Service classes is higher than the change for the Company in total. For example, Net Production Plant increased by 69 percent for the Company but 91 percent for the Residential class and 126 percent for the Small General Service class. Energy costs decreased 10 percent for the Residential class but less than the 16 percent decrease for the Company.

[14] NARUC Electric Utility Cost Allocation Manual January, 1992, page 50
[15] Email from Craig Jones dated 10/13/15 3:12 AM Item 1

Q. Is the Company proposing to return deferred funds to customers?

A. Yes. The Company is proposing to return approximately $9.3 million to customers on a one-time basis.[16] This refund would flow through the Purchased Power and Fuel Adjustment Clause ("PPFAC") and therefore be effectively allocated on an energy basis.

Q. What is the result of the Company's capacity allocation proposal in this case?

A. The use of the new DPROD allocation methodology (A&E-NCP) raises the allocation to lower load factor classes (more costs), while the use of an energy allocation methodology for the deferred funds reduces the allocation (less savings) to the lower load factor classes.

Q. Is the Company's proposal to change to a new DPROD cost allocation methodology and return the deferred funds on an energy basis inappropriate?

A. The Company's allocation proposal is not inappropriate; however, the effects on lower load factor classes is significant because the proposal is accompanied by a significant increase in power production capital costs.

Q. What is the impact of the change to the DPROD allocator?

A. The Company provided a comparison of the impact of demand allocators (Average & Excess & 4CP and Peaks & Average & 4CP) after the Company's proposed increase.[17] Assuming that only the production plant allocation methodology has changed, the class return for the Residential class has gone from 6.82 percent using P&A to 6.00 percent using A&E; Small General Service class 8.90 percent to 6.40 percent; Medium/Large General Service 9.84 percent to 12.96 percent; Large Power Service 8.76 percent to 9.06 percent; and Lighting 10.84 percent to 7.87 percent; while the overall Company remained constant (as it should) at 7.93 percent.

[16] Application page 6 (Table Gila River Deferred Savings)
[17] Jones Direct 25:11

Q. How have the returns of the classes changed between the present and prior CCoSS?

A. Exhibit HS-3 compares various items between the two CCoSS. In the 2012 CCoSS (12-0504) [line 12] all classes had positive class rates of return except the Mining class, while in the present CCoSS [line 33] the Residential and Small General Service classes have negative returns. A more consistent basis to compare returns uses the Unitized Rate of Return ("UROR") [lines 13 and 34], which is the class return divided by the Company return.

Q. Does the Company's allocation of income taxes by class have an impact on the returns calculated?

A. The Company appears to allocate class income taxes on the sum of return times rate base plus operating expenses (without income taxes). Using this methodology, positive taxes are allocated to a class that is not providing enough revenue to cover expenses. An alternative (sometimes used) calculates class income taxes based on the profitability of the class, more akin to how a business is taxed. This difference in methodology magnifies the disparity between positive and negative class returns. However, when all classes have positive returns close to the Company's return the effect is smaller and of less consequence than the other changes discussed above.

Q. What CCoSS recommendation does Staff have for the Commission?

A. There are two major effects operating in the same direction in this case. While the Company's net distribution plant has decreased by 1 percent, net production plant has increased by 69 percent. Simultaneously, the Company has changed its production plant allocation methodology from Average & Peak to Average & Excess–NCP. These two changes magnify the individual impact on classes, such as Residential and Small General Service. Therefore, the Commission should use the Company's CCoSS as a general guideline and invoke gradualism in its class revenue allocation decision for this case.

REVENUE ALLOCATION

Q. What non-cost considerations should the Commission consider during its deliberations on revenue allocation?

A. The Commission should consider the relative positions (from the CCoSS) of the classes along with the qualitative issues such as economic conditions for consumers, the business climate and past practices when deciding what portion of a revenue increase is allocated to each class. Also, the size of the classes limits how much the Commission can move a class at the conclusion of any single rate case. For example, the new Medium/Large General Service class is almost five times larger than the Small General Service class. The Residential class is six times larger than the Small General Service class and more than all other classes combined.[18]

Q. What principles do you use to allocate revenue among rate classes?

A. I have used the following principles:

- The individual rate classes should be gradually moved toward an UROR of 1.000 over one or more rate cases depending on the frequency of rate cases and the distance of the class' UROR from 1.000.

- There should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue.

- There should be a lower bound of 50 percent for any class' increase compared to the overall increase.

[18] Schedule G-1, Line 20 Total Electric Revenue From Sales

Q. Are there other concepts that apply in this case?

A. The purchase of the combined cycle generating unit was intended to stabilize energy costs, which provides benefits to all customers. Therefore, it would be inappropriate to reduce rates for any customer class because that would send a confusing message about the new plant expenditure.

Q. What is the Company's proposed revenue allocation?

A. Based on Schedules G-1 and G-2 [lines 22 and 20 respectively], the Company is proposing to allocate 91 percent of its requested $22.5 million increase to the Residential class, 11.8 percent to the Small General Service class, small amounts to the Medium/Large General Service classes and a reduction to the Large Power Service class.

Q. Have you modeled various revenue allocations based on Staff's recommended revenue requirements?

A. Exhibit HS-4 models Staff's proposed increase a number of ways. For comparison purposes the increase was allocated:

- Proportional to the Company's proposed revenue allocation percentages
- Equal percentage increase (across the board by revenue)
- Moving all of the classes to the same return (UROR equals 1.000)
- Moving the Residential and Small General Service classes 50 percent of the amount needed to reach parity (and increase all other classes by an equal 10.1 percent)
- Moving the Residential and Small General Service classes 60 percent of the amount needed to reach parity (and increase all other classes by an equal 6.3 percent)
- Moving the Residential and Small General Service classes 67.7 percent of the amount needed to reach parity (and increase all other classes by an equal 3.7 percent)
- Moving the Residential and Small General Service classes 75 percent of the amount needed to reach parity (and increase all other classes by an equal 0.5 percent)

Q. What is Staff's recommendation on revenue allocation?

A. Based upon the present and prior CCoSS, the principles discussed above, the impact of the purchase of the combined cycle plant and the relative impacts between classes, Staff recommends that the eventual revenue requirements be allocated by increasing the Residential and Small General Service classes 50 percent of the amount needed to reach parity and increasing all other classes by an equal 10.1 percent to obtain the total revenue requirement.

As shown within the box in Exhibit HS-4, under Staff's recommended revenue allocation the Residential and Small General Service classes receive 58.3 percent and 7.3 percent of the overall increase compared to the Company's proposal of 91.2 percent and 11.8 percent for those two classes respectively. Under Staff's proposal, all classes receive an increase while the Company's proposal decreased the revenue requirement for the Large Power Service class.

Q. If Staff's recommended revenue allocation is adopted what will the class returns be?

A. The results of the proposed revenue allocation are forecasted in Exhibit HS-4. All classes will have a positive return; the UROR of the "low UROR" classes (Residential and Small General Service) will increase and the UROR of the "high UROR" classes will decrease, moving all classes towards parity.

Q. Has the Residential class been subsidized by other classes in the past?

A. Yes. Exhibit HS-3 summarizes the Company's latest two CCoSS. In the 2012 CCoSS the UROR [line 13] is less than 1.0 for the Residential, Large Power Service and Mining classes indicating subsidization by the other classes. In the present CCoSS the UROR [line 34] is less than 1.0 for the Residential and Small General Service classes.

Q. Please explain why, if the Residential and Small General Service classes are being subsidized by other classes, Staff is not recommending class revenue increases to bring those classes to parity, which would be consistent with the rate design plan Staff is recommending and you have detailed above.

A. Staff's plan articulates the concept that "Rates should be based on costs derived from class cost of service studies…", however the plan is a *long-term* plan.

Exhibit HS-4 shows that to bring the Residential class to parity would require a class revenue increase of 116 percent of the total increase and an increase of 14.7 percent of the total increase for the Small General Service class (significantly higher than the Company's proposal). Exhibit HS-2 demonstrates that significant changes have occurred between the two CCoSS due to the impacts of the acquisition of a portion of Gila River Unit #3 and the change in the DPROD allocator.

As explained above, revenue allocation is not just an algorithm-based process but it is tempered by a Commission's evaluation of other factors. Also Staff's recommendation to move half way to removing the subsidy allows for the completion of the process in a following case.

RATE DESIGN

Q. Please summarize the Company's rate design proposal.

A. The Company's rate design objectives are "To align rate structures with our customers' evolving energy use", "To reduce the level of cross-subsidies between customers" and "To give the Company an appropriate opportunity to recover its fixed costs."[19]

[19] Hutchens Direct 6:16

The Company has focused on the use of a three-part rate design (customer, demand and energy charges) that would be mandatory for all new DG customers and optional for other Residential ("RES") and Small General Service ("SGS") customers.[20] The Company suggests that these changes are to better align the Commission's policies with the Company's need for fixed cost recovery and system usage.[21] The Company is also supporting gradualism when making rate design changes.[22] For new DG customers, the Company is proposing monthly bill credits for any excess energy delivered to the Company's system.[23]

Q. What was the Company's primary concern in developing its rate design proposals?

A. As I understand the Company's approach, the focus was on developing and then moving to a three-part rate in order to maintain the recovery of fixed costs. A concern is expressed that seasonal customers, vacant homes or businesses, and DG customers (with their associated low kWh consumption) limit the Company's ability to recover fixed costs.[24]

Q. Is this focus on fixed costs sufficient to support rate design changes?

A. If fixed costs are not properly accounted for in the rate design, intra-class subsidies will occur. The challenge is how to and how fast to make the changes. RES and SGS customers have a simple rate design and even the acceptance of TOU rates in these classes has been limited.[25] With new rate forms, some customers need education and support to achieve a meaningful transition.

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[20] Hutchens Direct 10:8, Dukes Direct 16:6 and 19.11
[21] Hutchens Direct 10:23
[22] Hutchens Direct 14:14
[23] Hutchens Direct 15:7
[24] Dukes Direct 11:14
[25] Schedule H-2-1 line 3 (230 customers)

Q. Is the Company's unit cost analysis in Schedule G-6-1 useful in evaluating its proposed customer charges?

A. Many of the concerns about the CCoSS do not apply to the direct customer costs. The Company also updated Schedule G-6-1 and the update should be used as a point of comparison.[26] The Company's information shows direct customer costs, an amount that includes meters, billing and collection, meter reading costs and the service line or drop. The Company has indicated that it used a minimum-sized system to allocate portions of the distribution system (such as poles, wires, transformers) to the customer component.[27] These costs are included in the customer-related unit costs.[28]

Q. What changes does the Company propose for the Residential Service (Rate RES-01) rate?

A. The Company is requesting an increase in the customer charge from $10.00 to $20.00.[29] Energy charges also are proposed to increase,[30] and the Company is proposing to eliminate the third tier for revenue stability reasons.[31]

Q. What changes does the Company propose for the TOU Residential Service (Rate RES-01 TOU) rate?

A. The Company is requesting an increase in the customer charge from $11.50 to $20.00 for TOU customers,[32] and adjustment in the rate to match the configuration of the Super Peak TOU rate.[33]

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[26] UNSE Response to STF 2.056 and STF 2.057
[27] UNSE Response to STF 2.069
[28] Email from Craig Jones dated 10/13/15 2:49 AM
[29] Jones Direct 40:23
[30] UNSE Schedule H-3, Page 1
[31] Jones Direct 42:1
[32] UNSE Schedule H-3, Page 1
[33] Jones Direct 42:13

Q. What are the residential customer costs?

A. The Company's information shows that direct customer costs are $14.73.[34] This amount includes meters, billing and collection, meter reading costs and the service (line or drop) and the components that form the minimum-sized system.

Q. What changes does Staff recommend to the RES-01 residential rate?

A. For the pre-transition period Staff recommends the following modifications of the Company's proposal:

- The existing rate design including the third tier (over 1,000 kWh) should be retained, but the inclination should be flattened by increasing all blocks by the same amount per kWh.

- All residential customer charges should be $15.00 to match the Company's costs. With the advent of AMI, all customers will be using the same meter.

- The revenue allocated to the Residential class should be collected first by an increase in the customer charge up to the level proposed here, with the remainder (if any) recovered by increased energy charges. Applying the revenue increase to the Customer Charge first will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

[34] UNSE Response to STF 2.057, Schedule G-6-1, Line 23 and Email from Craig Jones dated 10/13/15 at 2:49 AM

Q. What is the impact on residential customers of Staff's pre-transition recommendations?

A. Based upon Staff's recommended overall increase in revenue requirements along with its revenue allocation and pre-transition rate design changes, residential customers would see increases as shown in Exhibit HS-5 as compared to the Company's proposal.

Q. What changes does the Company propose for the Small General Service (SGS-10) rate?

A. For SGS customers, the Company is requesting an increase in the customer charge from $14.50 and $16.50 (TOU) to $30.00.[35] The energy charges also are proposed to increase.[36] This non-demand class will be limited to customers with a maximum energy consumption of 12,000 kWh.

Q. Is the Company's increase in the customer charge for Small General Service customers (SGS-10) appropriate?

A. The unit cost information in Schedule G-6-1 indicates that customer costs for the SGS Class are $29.74.[37]

Q. What changes does Staff recommend to the SGS rate?

A. For the pre-transition period Staff recommends the following modifications of the Company's proposal:

- The customer charge of $30.00 as requested by the Company is appropriate.

- The revenue allocated to the SGS class should be collected first by an increase in the customer charge up to the level proposed by the Company, with the remainder (if

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[35] Jones Direct 43:10
[36] UNSE Schedule H-3, Page 1
[37] UNSE Response to STF 2.057, Line 23

any) recovered by increased energy charges on a proportional basis between blocks. Applying the revenue increase to the Customer Charge first will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

- The Company's proposal to move a customer to the new MGS rate "if the customer's consumption meets or exceeds 12,000 kWh in consecutive months" is vague as the number of months is not defined, nor has the impact been determined. Absent further information, Staff does not support this provision and suggests the Company address this issue in its rebuttal testimony.

Q. The existing RES and SGS rates are not Three-Part-TOU rates and therefore are not in accordance with the Staff's rate design plan. How would these rates transition?

A. Staff recommends that the Commission approve in this proceeding a mandatory transition to Three-Part-TOU rates for RES and SGS customers subject to a Company-filed transition plan.

The transition would not begin until the Company is able to provide each customer with at least three months of demand and TOU data from AMI meters. Transition would be done in phases of about one quarter of the class at each time. The transition could start as early as January 1, 2017, which would give the Company approximately six months to develop its customer education program and implement one or more means of providing data to customers before the transition begins. This transition would be complete by the end of 2017.

The Company would also need to provide data to these customers on an on-going basis in an easy to self-retrieve form such as a mobile application, website, or on the bill. The application or website would also provide tools and educational materials for the customer to demonstrate how to manage and reduce demand.

Q. What rates would be used for the transitioned customers?

A. Three-Part RES and SGS TOU rates would be designed to match the existing two-part rates approved at the conclusion of this case. The demand charge would not exceed 75 percent of the unit costs for distribution[38] to lessen the impact while customers learn to manage their demand. There would be no demand ratchet[39] to avoid penalizing customers for one-time demand excursions. Demand rates would apply only to On-Peak periods. There would be no change to the TOU periods in effect now.

Q. How would the transition affect the rates paid by RES and SGS customers?

A. There should be no customer class impact because the Three-Part TOU rates would be designed to match the pre-transition two part rates and recover the same class revenue requirements. However, under any transition between rates, those customers that are not similar to average customers within the class will see positive (lower bills) or negative (higher bills) impacts. This is why customer education and information is necessary.

Q. Would there be monitoring of the transition?

A. Yes. Revenue monitoring and customer complaint tracking on a class, phase and individual customer basis should be provided to Staff each quarter and filed in this docket.

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[38] UNSE Schedule G-6-1, lines 19 and 20

[39] A demand ratchet stipulates that a customer's billing demand cannot be less than a stated percentage (sometimes as high as 100 percent) of maximum demand during a previous period (usually twelve months ending with the current month). Gas Rate Fundamentals (Fourth Edition), American Gas Association, 1987 page 170-171

Q. What would start each phase into transition?

A. The transition for the next phase would be determined after the preceding phase was on the three-part rate for at least four months. If the customer impact, education and information delivery was working well, then the next phase could be initiated.

Q. How would a phase be determined?

A. Staff recommends that the phases be selected based on energy consumption with the largest consumers to be first. These customers should have the greatest flexibility to manage their demand and consumption.

Q. Would residential DG customers be moved to the RES-01-Demand (or TOU) at the close of this case as requested by the Company?

A. No. Consistent with the long-term rate design plan, the actions taken behind the meter of any customer are not the sole determinant of which rate the customer must take. All DG customers would transition with their respective residential customer phase.

Q. What is the Company's proposal for a new Medium General Service ("MGS") rate?

A. The Company wants to establish a new MGS rate for existing Large General Service ("LGS") customers with demand between 20 kW and 750 kW.[40] This rate will have the same demand measurement and ratchet as the previous LGS class. The Company is requesting an increase in the customer charge from the $50.00 and $52.00 (TOU) (now charged to these customers presently on the existing LGS rate) to $100.00. Demand charges are proposed to increase from $12.81 to $13.05 per kW.[41] The Company is proposing that any customer that exceeds the 750 kW cap "for a billing month will be automatically moved in the subsequent month to

[40] Jones Direct 43:17 and 43:25
[41] UNSE Schedule H-3, Page 2

the new LGS rate class. The customer must remain there for at least 12 months without exceeding the 750 kW demand to qualify to move back to MGS."[42]

Q. Is the Company's proposal to create a new Medium General Service rate class and MGS rate schedule appropriate?

A. Yes. The present LGS rate includes customers with a wide range of demands and adding the MGS rate is appropriate.

Q. Is the Company's customer charge for MGS customers appropriate?

A. The unit cost information in Schedule G-6-1 indicates that customer costs for the Medium/Large General Service Class are $264.73.[43] Unfortunately, the unit costs were not differentiated between the MGS and LGS rate class.

Q. What changes does Staff recommend to the MGS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The three-part rate design is appropriate as it retains the existing rate structure.

- The $100 customer charge requested by the Company may be appropriate in light of the mixed CCoSS for Medium/Large General Service. Staff requests that the Company differentiate Medium General Service customer costs from Large General Service in its rebuttal.

- The revenue allocated to the MGS rate should be collected first by an increase in the customer charge up to the level proposed by the Company, with the remainder (if

[42] Jones Direct 43:25
[43] UNSE Response to STF 2.057, Line 23

any) recovered by increased demand and energy charges. Applying the revenue increase to the Customer Charge first and then to demand charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

- The Company's proposal that "any customer exceeding the cap for a billing month will automatically be moved, in the subsequent month, to the new LGS rate class", is abrupt and too short a period to determine if the move is appropriate, nor has the impact been determined. Absent further information, Staff does not support this provision and suggests the Company address this issue in its rebuttal testimony.
- The Company should split the Medium/Large General Service cost of service class into two cost of service classes in its next rate case to verify the costs to be used in the respective rate designs.

Q. What changes does the Company propose for the Large General Service ("LGS") rate?

A. For LGS rate customers, the Company is requesting an increase in the customer charge from $50.00 and $52.00 to $300.00. Demand charges are proposed to increase from $12.81 to $12.96 per kW.[44] This class will have a minimum demand of 450 kW, and there will be no demand cap.[45] This class is now for customers served at less than 69 kV.[46]

Q. How can customers subject to the minimum demand of 450 kW be protected?

A. The Company has not detailed whether the new minimum demand of 450 kW will impact any customers and the extent of that impact.

[44] UNSE Schedule H-3, Page 2
[45] Jones Direct 44:4
[46] Jones Direct 44:12

Q. Is the Company's increase in the customer charge for LGS customers appropriate?

A. The unit cost information in Schedule G-6-1 indicates that customer costs for the Medium/Large General Service Class are $264.73.[47]

Q. What changes does Staff recommend to the LGS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The three-part rate design is appropriate as it retains the existing rate structure.

- The $300 customer charge requested by the Company may be appropriate in light of the mixed CCoSS for Medium/Large General Service. Staff requests that the Company differentiate Medium General Service customer costs from Large General Service in its rebuttal.

- The revenue allocated to the LGS rate should be collected first by an increase in the customer charge up to the level proposed by the Company, with the remainder (if any) recovered by increased demand and energy charges. Applying the revenue increase to the Customer Charge first and then to demand charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

- The proposal to impose a minimum demand of 450 kW has not been supported in the Company's filing. Absent support indicating the number of customers affected and the extent of the impact, Staff does not support this provision and suggests the Company address this issue in its rebuttal testimony.

[47] UNSE Response to STF 2.057, Line 23

Q. What rate changes does the Company propose for the Large Power Service ("LPS") customer class?

A. For LPS rate customers, the Company is requesting no change in the customer charge of $1,200.00.[48] Demand charges are proposed to decrease from $17.00 to $12.48 per kW.[49] This demand class will continue to have a minimum demand of 500 kW.[50] At present, LPS customers are subject to an 11-month 100 percent demand ratchet.[51]

Q. Is the Company's no change in the customer charge for Large Power Service customers appropriate?

A. The unit cost information in Schedule G-6-1 indicates that customer costs for the Large Power Service Class are $2,149.58.[52]

Q. What changes does Staff recommend to the LPS rate?

A. Staff recommends the following modifications of the Company's proposal:

- The three-part rate design is appropriate as it retains the existing rate structure.

- The customer charge should be set at $1,500 to move toward a cost based rate.

- The revenue allocated to the LPS rate should be collected first by an increase in the customer charge up to the level proposed here, with the remainder (if any) recovered by increased demand and then energy charges. Applying the revenue increase to the Customer Charge first and then to demand charges will increase recovery of fixed charges and reduce the impact within the LFCR mechanism.

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[48] Jones Direct 44:19
[49] UNSE Schedule H-3, Page 2
[50] Jones Direct 44:21
[51] Jones Direct 46:8
[52] UNSE Response to STF 2.057, Line 23

Q. Is the Company's proposal for TOU rates for schools appropriate?

A. The Company is proposing a new MGS-TOU-S rate that will replace the smaller SGS-TOU School rate, which has no customers. These rates are similar to the respective TOU rates.[53] However, the energy charges for the LGS-TOU-S rate appear to be slightly higher than the LGS-TOU rate with only a slight difference in the Summer On-Peak period. The Company has not provided enough information to render an opinion on these rates. Staff suggests the Company address this issue in its rebuttal testimony.

Q. What changes is the Company proposing for the Lighting Service rate?

A. The Company is proposing increases in the service charge and the per watt charge in order to raise the performance of this allegedly underperforming class.[54] The wattage charge does not define whether it is solely the lamp wattage or if a ballast load is included.[55] Staff suggests the Company address this issue in its rebuttal testimony.

Q. Does Staff agree with the rate changes that the Company has proposed for the Lighting Service rate?

A. No. There is very limited testimony supporting the increase, and Schedule G-1 indicates the Lighting class has a return of 3.94 percent compared to a total system return of 2.31 percent.[56] After the Company's proposed increase the class will have a return lower than the total system return.[57] Further clarification is required before a recommendation can be made. Staff suggests the Company address this issue in its rebuttal testimony.

[53] Jones Direct 48:24
[54] Jones Direct 49:17
[55] Exhibit CAJ-4 Schedule LTG
[56] UNSE Schedule G-1, line 39
[57] UNSE Schedule G-2, line 37

Q. Is there some risk when significant rate design changes are made?

A. Yes. Rate design changes may have unintended results for "outlier" customers that do not fit neatly into their apparent customer class. This risk is increased when customer research is limited or has not been performed.

Staff recommends, as provided for in the previous TEP settlement (Docket No. E-01933A-12-0291) and detailed above, the Commission should keep the rate design portion of this rate case open for at least six months after the completion of the transition (or 18 months after the rate effective date), whichever is later, to account for unanticipated customer rate impacts that are determined to be inconsistent with the public interest.

CARES

Q. Please describe the Company's proposal for CARES?

A. The Company is proposing to change the CARES rate to a flat monthly $10 discount from the RES-01 rate and to eliminate the exclusion of CARES customers from the DSM surcharge.[58] Existing CARES customers will be frozen on the present configuration of a reduced Basic Service Charge and a declining discount on energy usage. The freezing of this rate is similar to the now frozen CARES-medical rate.[59]

Q. What is the value/cost of the CARES discounts?

A. The Company estimates the discounts totaled $581,326 during the Test Year.[60]

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[58] Jones Direct 54:9 and 55:7
[59] Jones Direct 54:18 and 55:13
[60] Jones Direct 55:4

Q. Is eliminating the DSM exclusion appropriate?

A. Yes. This subset of customers should not be excluded from a surcharge for reasons extraneous to the surcharge, which is the case with the DSM surcharge. The exclusion creates additional bookkeeping problems for the surcharge and its reconciliation. This exclusion has been eliminated at the Company's affiliate TEP.[61]

Q. Does Staff support the CARES proposal?

A. In keeping with Staff's long-term plan for rate design, the Staff supports the Company's CARES proposal subject to a few concerns.

- The Company should "prove out" that the level of CARES discounts after changes in rates and the removal of the exclusion of the DSM surcharge is at or above the Test Year amount of $581,326. This proof can happen anytime or later during a post decision compliance filing if there is no settlement.

- The roster of CARES customers should be examined, and any existing CARES customer who would be better off (on an annual basis) on the flat monthly $10 discount should be moved to the new CARES RES-01 discount rate.

- The Company should develop a CARES provision that would apply to customers that are transitioned to the Three Part-TOU rate.

[61] Jones Direct 55:20

Interruptible Rates

Q. Please describe the Company's interruptible rate proposals?

A. The Company is proposing to introduce a new interruptible Rider R-12 and freeze the current Interruptible Power Service ("IPS") rate and also increase the rate above the level proposed for most LGS customers since the CCoSS shows them to be "highly subsidized".[62] In response to a Staff data request, the Company replied, "Customers on the IPS rate do not substantially differ in size or usage habits from the Large General Service customers. Therefore, they were included in the cost allocation process as if they were Large General Service customers."[63]

Q. Have the IPS customers experienced an interruption?

A. The Company notes, "[t]hey have not been interrupted in recent years and therefore provide no quantifiable benefit to the system." In the last case, the Company added a provision allowing for remote interruption and the Company alleges that this caused the number of IPS customers to drop from 39 to 29.[64]

Q. Has the Company provided enough information to verify the subsidization of IPS by other LGS customers?

A. No. Staff suggests that the Company address this issue in its rebuttal testimony.

Q. Please describe the Company's new interruptible proposal?

A. Rider R-12 provides for customers to consider on or after each March 15th the Company's Market Value Capacity Price ("MVCP") for the coming months May through September. The information supporting the MVCP will be available to Staff for review. Customers have

[62] Jones Direct 52:3
[63] UNSE Response to STF 2.112
[64] Jones Direct 52:19

until April 15th to nominate interruptible load and will receive Interruptible Credits ($/kW) for each of the five summer months.[65] This proposal is similar to the tariff provision recently approved for TEP.[66]

Q. Does Staff support this new interruptible proposal?

A. Yes. The Rider R-12 proposal is based on market reflective costs for each year and is subject to review by Staff. Customers retain the ability to evaluate the offer each year and consider the value compared to the customer's costs under the business conditions in place for that year and decide whether to participate. This concept provides significant flexibility for customers.

Q. Does the existing IPS rate serve a useful purpose?

A. Customers on the existing IPS rate have not been interrupted and may be receiving a subsidy. Staff recommends that this interruptible provision be eliminated at the end of the Company's next rate case. This will put IPS customers on notice of the change so they can prepare to deal with either standard rates or transfer to the new Rider R-12 interruptible provision.

Distributed Generation

Q. What is the Company's proposal for excess energy produced by distributed generation and fed back into the Company's system?

A. The Company has proposed a new net metering rider that allows customers with DG to sell excess energy production to the Company at the Renewable Credit Rate.[67] This proposal would apply to all customers who submitted a completed application after June 1, 2015, while

[65] Exhibit CAJ-3 Rider R-12 Sheet 712-1
[66] Jones Direct 53:18
[67] Dukes Direct 2:11

existing DG customers (and applications submitted before June 1, 2015) would stay on the current rider for up to 20 years from the date of approval.[68]

Q. Does the Company's proposal eliminate the banking option for new DG customers?

A. Yes. The Company proposes to pay for energy received with a monthly bill credit.[69]

Q. Is the Company proposing that all DG customers move to a three part rate?

A. Yes.[70] The proposed rates are (RES-01 Demand, RES-01 Demand TOU, SGS-10 Demand, and SGS-10 TOU).[71]

Q. How is the Renewable Credit Rate ("RCR") defined?

A. The Company proposes a RCR of 5.84 cents per kWh, which it argues is equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of the Company's affiliate TEP. The project in question is due for completion in 2015.[72]

The Company indicates that it would file an annual RCR update similar to the existing Market Cost of Comparable Conventional Generation when it makes its annual REST filing based on the most recent comparable utility scale purchased power agreement for renewable energy connected to the Company's or TEP's distribution systems,[73] which are under a common balancing authority.[74]

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[68] Dukes Direct 4:12
[69] Dukes Direct 4:17 and Tilghman 8:11
[70] Dukes Direct 4:26 and 23:4
[71] Dukes Direct 24:3
[72] Tilghman Direct 7:9
[73] Tilghman Direct 8:4
[74] Tilghman Direct 7:22

Q. Is a utility scale photovoltaic facility a reasonable proxy for the value of energy provided by photovoltaic DG?

A. The Company argues that a utility scale photovoltaic facility is a reasonable proxy for photovoltaic DG because it has similar production characteristics (seasonality, time of day and response to weather). If the procurement of the utility scale energy is from one or more independent suppliers, then the resulting price is a reasonable estimate of the market value at that approximate location at that point in time and for the period of the Purchase Power Agreement ("PPA").

Excess energy from a photovoltaic DG installation is not entirely representative of a utility scale PV facility because the DG customer is providing the net output equal to the photovoltaic output less any energy consumed by the customer.

Q. Did your examination of the information provided by the Company raise any questions about the proposed 5.84 cents per kWh price?

A. Yes. The Company response to STF 2.038 is classified as competitively sensitive, and I have not included any specific items or values here. The original PPA was not provided, the Company only provided the 5th amendment and a series of exhibits.

The facility, which the Company characterizes as the "most recent utility scale renewable energy purchased power agreement," is not a standalone facility, but the second phase of a two-phase facility. The price paid for the first phase is above the proposed 5.84 cents/kWh RCR. It appears that the costs of interconnection, which are to be paid for by the Seller, may be included within the first phase's rate and are not mentioned in relation to the second phase's rate.

There is no mention of whether the Buyer or the Seller has the rights to the Renewable Energy Credits ("RECs") for the energy sold. Rider R-10 and Rider R-11 also do not mention RECs or which party will have title to them.[75] This is important as RECs have value, and it is not clear whether the Company is offering the RCR for energy alone or energy and the associated RECs.

The Seller is responsible for losses to the point of delivery and the Buyer (TEP) is responsible for losses incurred after the point of delivery. While the Company is an affiliate of TEP, the Seller's facility is not connected to the Company.

Q. Did the Company perform a system loss study?

A. Yes. The Company provided a loss study[76] (classified as competitively sensitive) that is based on identifying inputs (generation and purchased power) and outputs (retail and wholesale sales), and the remaining energy is considered losses. Since the Company still procures significant energy through power purchases and it appears that the power purchases are net of losses, then the losses in the study provided would appear to be understated. This concern is validated by the Company's email response.[77] Informally the Company indicated that Western Area Power Administration ("WAPA") uses a blanket 3 percent loss for its transmission of energy within its load research work.[78]

Q. How should the purchase price for excess DG energy be adjusted for losses?

A. Most of the energy the Company generates or purchases should be assumed to transit the WAPA system, the Company's transmission system, and for most customers the Company's distribution system. A portion of the energy consumed by a distribution customer is lost

[75] Exhibit CAJ-4
[76] UNSE Response to STF 2.062
[77] Email from Craig Jones dated 10/13/15 3:12 AM Item 4
[78] On-site load research interview on 9/8/15

from the point of generation to the ultimate customer. Since it is likely that energy is provided by a DG customer to nearby neighbors, losses should be added to the RCR. Based on the Company's loss study[79] plus the WAPA allowance, losses could be substantial.

Q. What other potential savings and costs are due to the existence of DG?

A. There may be savings in transmission charges; however, the Company has not addressed this issue. Other parties to this case may be able to add to the record in this area.

Some participants may consider savings from deferred or avoided distribution investment. The Company has identified a TEP substation[80] as a possible preferred location for the installation of solar generation along with supporting technologies. If DG can be shown to defer or eliminate required distribution investment, DG customers that provide the needed "support" should receive a locational adder to the RCR. Other parties to this case may be able to add to the record in this area.

Q. Does Staff have a recommendation as to how to determine the value of excess energy?

A. It is early in this proceeding and many interested parties have not yet filed their positions on the value of excess energy. Also, as Staff witness Thomas M. Broderick has detailed, Commission Docket No. E-00000J-14-0023, which is intended to examine the value and cost of DG, may provide useful information to the parties in this rate case. Therefore, for the time being, Staff does not propose any changes to the existing net metering tariff or waivers of the net metering rules but it may update its position in its Surrebuttal testimony or later at the hearing in this case. If ultimately the Commission continues to rely upon net metering, the migration to a three-part tariff will not pose any issues as the energy kWh charges in a three-part tariff and on a time-of-use basis would be used for net metering.

[79] CONFIDENTIAL UNSE Response to STF 2.062
[80] UNSE Response to STF 2.034

Service Fee Changes

Q. Please describe the changes proposed by the Company to the UNSE Electric Statement of Charges?

A. The Company is not proposing increases to the following charges:

- Service Transfer Fee
- Customer Requested Meter Re-read
- Special Meter Reading Fee
- Returned Payment Fee
- Late Payment Finance Charge

The Company is proposing increases to the following charges:

- Service Establishment, Reestablishment or Reconnection of Service (regular business hours), along with a different and higher charge for after regular hours and weekends and holidays
- Service Reestablishment under other than usual operating procedures including Automated Meter Reading Opt-Out Set Up Fee
- Meter Test

The Company is requesting a new charge for Consumption History Request and Interval History Request on an hourly basis.[81]

Q. What did you find during your review of the cost support data for these charges?

A. In response to a Staff data request, the Company provided a worksheet detailing the underlying costs for each of these charges.[82] After Staff's review, a supplemental worksheet was provided. This revision lowered the charge for the Consumption History Request and Interval History Request to $60 per hour, which is reasonable based on the costs provided.

[81] Exhibit CAJ-3 Original Sheet 801 and Jones Direct 70:9
[82] UNSE Response to STF 2.077

Q. What other concerns do you have with the Consumption History Request and Interval History Request charge?

A. There appears to be some confusion as to when this charge will be applied. The Company states this charge will apply only after the first time a customer requests interval data, but this is not clear on the Statement of Charges.[83] Also, this charge should not apply if the Company develops a means to allow customers to look up or request their usage information online or through a mobile application that does not require the work of an employee. Finally, Staff recommends that this charge not apply for a period of six months after the mandatory transition of RES, SGS and MGS customers.

Q. Is the inclusion of Automated Meter Opt-Out Set-Up within the classification of Service Reestablishment under other than usual operating conditions appropriate?

A. No. The proposed charge of $196 for the Automated Meter Opt-Out Set-Up Fee has been set using a minimum 2 hours of an On Call Lineman. Changing the meter for an Opt-Out customer does not have to be done as a special after hours event and can be scheduled during normal working hours. Therefore, the charge should be $47 for Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours to reflect this situation.

Buy-Through

Q. Please describe the "Buy-Through" proposal submitted by the Company?

A. The "Buy-Through" was required to be introduced by the Company as a result of a settlement during the merger process,[84] but the Company does not support this tariff

[83] Jones Direct 70:9
[84] Jones Direct 56:3

change.[85] The Company indicates that the conceptual structure is similar to the "Buy-Through" provision in use at Arizona Public Service Company.[86]

The Company proposes that all revenue lost under this program, which it calls a "cost shift",[87] would be recouped from other customers through the LFCR mechanism.[88] This amount is significant and estimated by the Company at $331,200 annually in years two through four of the program.[89]

Q. What is the Staff position on the "Buy-Through"?

A. Because the Company is not supporting this concept, there is no record describing the benefits to non-participating customers. Staff looks forward to testimony in support of the "Buy-Through". Staff does not object to a "Buy-Through" mechanism if there are no adverse impacts and no costs to all other customers. Staff opposes recouping any allegedly lost Buy-Through revenue in the LFCR and likewise opposes any deferral of allegedly lost Buy-Through revenue.

AMI Opt-Out

Q. What is the AMI Opt-Out?

A. Some customers have raised concerns about the use of meters that transmit data wirelessly back to the Company. These customers wish to retain their existing mechanical meters, which would then require the Company to read the meter by travelling to the Opt-Out customer's premise, which raises the costs of serving these customers compared to all other customers.

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[85] Jones Direct 56:8
[86] UNSE Response to STF 2.115
[87] Jones Direct 58:19
[88] Jones Direct 59:1
[89] UNSE Response to STF 2.118

Q. Is the retention of mechanical meters for Opt-Out customers appropriate?

A. No. If the Commission endorses Staff's rate design plan, all customers will need to have meters that record interval data in order to implement Three-Part TOU rates. Mechanical meters cannot provide the data required for, and the potential benefits of, new rate forms. Further, if Opt-Out customers could avoid demand metering, then other customers might opt out solely for rate design objections, thus raising the number of mechanical meters and the number of those meters that must be read by a visit to the customer's premise.

Q. Is there an alternative that deals with the concerns and provides the interval data for new rate forms?

A. This issue was raised informally with the Company and it suggested a solid-state meter with recording capabilities, which accumulates but does not transmit information.[90] The Company would read the interval data by visiting the customer's premise monthly.

Q. What is Staff's recommendation?

A. If a customer decides to Opt-Out, the Company should install a non-transmitting recording device and read that meter monthly. Because the number of Opt-Out customers is expected to be small and geographically dispersed, the costs of the monthly meter reading should be the Special Meter Reading Fee that requires a premise visit. The costs of the new meter installation should be recouped from the customer requesting this non-standard meter (at the $47 for Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours) along with the monthly reading costs (at the $26 Special Meter Reading Fee). Staff will monitor the number of special read customers to determine if the Special Meter Reading Fee remains appropriate as the number of customers using the Opt-Out develops.

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[90] Email from Brenda Pries dated 11/23/15 at 11:30 AM

Economic Development

Q. Please describe the economic development program proposed by the Company?

A. The Company is proposing an Economic Development Rider R-13 ("EDR") for current or potential commercial or industrial customers that meet certain economic development criteria within the Company's service area. The EDR will be available to customers with a projected peak demand of 1,000 kW or more and a load factor of 75 percent or higher. Discounts would decline over a five-year period. New load would be limited to 50 MW.[91]

Q. What reasons did the Company provide as support for the EDR program?

A. The Company argues that its service territory has been slow to recover from the economic downturn post 2007 and that it has lost several of its largest customers in the past few years, resulting in lower sales over which fixed costs can be spread.[92]

Q. What are the specific qualifications to obtain the EDR?

A. The EDR qualifications are linked to existing Arizona state tax credit programs, which appear to be designed to create new in-state above median wage jobs with healthcare benefits.[93]

Q. What levels of discount are offered?

A. For economic development (requires the building of new facilities), the discount starts at 20 percent and declines to 2.5 percent. For economic redevelopment (occupying vacant facilities), the discount starts at 30 percent and declines to 5 percent.[94]

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[91] Dukes Direct 31:22
[92] Dukes Direct 30:15
[93] Dukes Direct 32:6
[94] Dukes Direct 32:17

Q. How will the discounts be recouped?

A. The Company's proposal did not address this issue. Staff explored this question in a data request. The Company responded that most of the revenues will reduce incremental revenues between rate cases, but the Company may request some form of consideration in future rate filings if the discounts extend into a new rate period, subject to full evaluation and Commission approval.[95]

Q. Will existing customers be protected from the impact of new capital expenditures?

A. The Company's proposal did not address this issue. Staff explored this question in a data request. The Company responded that the present rules and regulations approved by the Commission governing line extensions and new services would apply equally to these new customers or incremental loads.[96]

Q. At present the Commission is encouraging energy efficiency so isn't the EDR program the direct opposite because it will increase energy sales?

A. Conceptually, electric energy efficiency programs have not focused on limiting the increase in new customers but focused on increasing the efficiency of energy usage. Economic development rates can increase the number of employers, employees and maybe machinery and are expected to provide economic benefits within the utility's service territory. The Company's EDR program is geared towards the reuse of vacant facilities, which have some existing unused (or underused) electrical distribution capacity. Although EDR customers are proposed to be on a standard rate schedule with a discount, if the Commission is concerned about load growth, requirements could be added, such as using only time-of-use rates and/or the Rider R-12 interruptible service.

[95] UNSE Response to STF 2.023
[96] UNSE Response to STF 2.024

Q. What is Staff's recommendation for the EDR?

A. The proposed EDR has limits and is biased towards existing facilities. The Company should address the potential impact of new energy requirements for the incremental load in its rebuttal. Assuming that the energy costs are not significant, then Staff supports this limited (volume and time) program to increase employment in the service territory. Staff's support does not extend to any request for recoupment of the lost incremental revenues absent a supporting record in some future proceeding.

LOST FIXED COST RECOVERY

Q. What purpose does the LFCR mechanism serve?

A. The LFCR mechanism, as approved by the Commission, serves to compensate the Company between rate cases for the revenue lost by the Company's compliance with established requirements for EE and DG.

Q. What is your experience with the LFCR mechanism in Arizona?

A. On behalf of Staff, I sponsored the LFCR mechanism in the Arizona Public Service ("APS") rate case (Docket No. E-01345A-11-0224), the TEP rate case (Docket No. E-01933A-12-0291) and the last UNSE rate case (Docket No. E-04204-12-0504).

Q. Please describe the Company's LFCR proposal in this proceeding.

A. The Company's LFCR proposal[97] is to change the established LFCR mechanism to increase the revenue recovered due to the effects of energy efficiency and distributed generation and to add a new category of recovery[98] due to the operation (if approved) of a "Buy-Through" provision (which the Company notably does not support)[99] added to the Company's tariff.

[97] Jones Direct 74:11
[98] Jones Direct 59:5
[99] Jones Direct 56:8

The Company also proposes to modify the LFCR mechanism as it appears to customers by removing the Fixed Cost Option[100] and presenting the charges on the bill as a single line item rather than its present split into EE and DG portions[101].

Q. What is the revenue impact of the Company's proposed changes to the LFCR mechanism?

A. The Company estimates the impact of the recovery of generation costs and 100 percent of the demand costs to be $573,000.[102] Although Staff's discovery request had asked for these two items separately, the Company has provided a combined amount.[103] The Company estimates that the expansion of the LFCR mechanism to include the recovery of revenue lost due to a "Buy-Through" provision in the tariff is $331,200 annually in years two through four.[104] If the Company's requested increases in the Basic Service Charge are implemented, then the impact of the LFCR is mitigated by an estimated $509,000.[105]

Q. What changes is the Company proposing that will affect the presentation on the customer's bill?

A. Presently, the utility is required to show the EE and DG components of the LFCR mechanism on the bill as two separate items. The Company is proposing to combine the two items (and I presume the new "Buy-Through" costs) into single line items.[106]

The Company is also asking for permission to no longer offer the Fixed Cost Option in the LFCR mechanism.

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[100] Jones Direct 77:15
[101] Jones Direct 77:7
[102] Jones Direct 75:18
[103] UNSE Response to STF 2.121 and 2.119
[104] UNSE Response to STF 2.118
[105] UNSE Response to STF 2.119
[106] Jones Direct 77:7

Q. What portions of the Company's proposal to modify the LFCR mechanism do you recommend that the Commission accept?

A. I support the Company's proposal to remove the Fixed Cost Option from the LFCR because no customer has used that option at the Company[107] or at the Company's affiliate TEP.[108]

Q. What portions of the Company's proposal to modify the LFCR mechanism do you recommend that the Commission not accept?

A. The Commission should not accept the proposals that will increase the revenue impact on customers including:

- Allowing the Company to receive recovery for generation costs
- Increasing the recovery for distribution demand costs from 50 percent to 100 percent
- Increasing the cap on recovered costs allowed for each year from 1 percent to 2 percent
- Expanding the LFCR mechanism to include revenues lost from a "Buy-Through" provision to be established in the Company's tariff

Further, the Commission should not accept the change proposed by the Company to combine the EE and DG portions of the mechanism on the customer's bill as that provision was originally implemented by the Commission[109] and serves to highlight for the customer the relative impacts of EE and DG, which affect different customer subclasses. Also, adopting a single charge would conceal the recovery of "Buy-Through" costs from customers, if that proposal were accepted.

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[107] Jones Direct 77:15
[108] Email from Craig Jones dated 9/21/15
[109] July 11, 2013, Open Meeting

Q. Why should the Commission reject including generation and purchased power in the LFCR mechanism?

A. The Company's purchased power program[110] appears to have a significant amount of flexibility that would allow the Company to adjust its purchases to match its short-term needs, and purchased power is fungible. Purchased power is not affected if energy is delivered to a new customer, an existing customer using slightly more energy, or sold off-system. Therefore, the Company has many opportunities to adjust its energy supply.

Q. What is the Company's forecast for sales?

A. The Company's load forecast shows a trend of increasing total numbers of customers[111] and the reference case (without the effects of EE and DG) shows increasing sales to retail customers.[112] The reference case for peak demand also shows increasing customer demand.[113]

Q. Could the proposed EDR and the Company's LFCR changes create a situation where some generation could be double collected?

A. Yes. The Company is proposing an economic development rate in this case that if successful would increase energy sales, peak demand and revenue. In an unusual twist, if the Company's proposal to include generation in the LFCR mechanism is approved, the Company could bill existing customers for the generation costs within the LFCR mechanism, redirect the generation (energy and capacity) to a new customer attracted by the proposed economic development rates and effectively double collect on that load.

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[110] UNSE Response to STF 2.073
[111] UNSE 2014 Integrated Resource Plan Chart 6 (page 39)
[112] UNSE 2012 Integrated Resource Plan Chart 9 (page 43)
[113] UNSE 2012 Integrated Resource Plan Chart 10 (page 44)

Q. Why should the Commission reject increasing from 50 percent to 100 percent the distribution demand component in the LFCR mechanism?

A. Distribution costs are not as fungible and some distribution assets cannot serve other customers within the short term. Therefore, a reduction in per customer sales may result in a shortfall in revenues to cover distribution fixed costs. The LFCR adopted by the Commission provides a mechanism to recapture the portion of distribution costs that are collected on a volumetric (per kWh) basis. Some of the Company's rate schedules collect distribution costs using demand charges, which will remain constant or change slower than a straight volumetric rate.

Q. Why should the Commission reject increasing from 1 percent to 2 percent the cap in the LFCR mechanism?

A. The existing LFCR mechanism has not reached the 1 percent cap.[114] I also expect the Commission's treatment of DG to evolve at the end of this case and that would also mitigate the need to raise the cap. If the Commission does not accept the Company's proposed changes to the LFCR, then the increase in the cap is not necessary.

Q. Should the Commission reject including the costs of a Buy-Through" provision in the tariff in the LFCR mechanism?

A. The "Buy-Through" was required to be introduced by the Company as a result of a settlement during the merger process,[115] and the Company does not support this tariff change. It appears that this provision would allow one or more large customers to take advantage of lower costs within the energy supply market, and the Company is asking all other customers to absorb its potential lost revenues in years two through four of the provision. Effectively, the Company's request to include "Buy-Through" within the LFCR

[114] Jones Direct 77:20
[115] Jones Direct 56:3

mechanism forces all customers to subsidize the potential savings for a small class of large, sophisticated customers. This attempt at cross subsidization should be rejected.

Q. What changes does Staff recommend for the LFCR mechanism?

A. As highlighted in the testimony of Staff witness Thomas M. Broderick, Staff will recommend in the Company's next rate case that the DG portion of the LFCR be eliminated. In this case Staff recommends that the DG portion of the LFCR apply only to lost fixed costs from the end of the Test Year until the rate effective date. Staff's long-term rate design plan recognizes that DG is no different than other customer initiatives to control their costs. Further, Staff has recommended increases in customer and demand charges for existing rates along with the mandatory transition to Three Part-TOU rates for Residential and Small General Service customers, all of which reduce the need for the LFCR mechanism by increasing the recovery of fixed costs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Testimony - Howard Solganick

Arizona Corporation Commission
Case – UNS Electric Docket No. E-04204A-12-0504 (June 2013 and July 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Tucson Electric Power Company Docket No. E-01933A-12-0291 (December 2012 and January 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November and December 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission

Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica Public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days

Exhibit HS-2

LINE	CCoSS Comparisons	A	B	C	D	E	F	G	H	I	J	K	L	M
		2014 CCoSS					2012 CCoSS					% Increase 2012 to 2014		
		Total UNS	Residential		SGS		Total UNS	Residential		SGS		Total UNS	Residential	SGS
			$	%	$	%		$	%	$	%			
1	Generation													
2	Tot Prod Plant	173,860,268	105,138,005	60.5%	14,956,558	8.6%	93,861,601	50,033,745	53.3%	6,039,021	6.4%	85.2%	110.1%	147.7%
3	Accum Depr	37,652,975	22,769,772	60.5%	3,239,147	8.6%	13,115,049	6,991,091	53.3%	843,817	6.4%	187.1%	225.7%	283.9%
4	Net Plant	136,207,293	82,368,233	60.5%	11,717,411	8.6%	80,746,552	43,042,654	53.3%	5,195,204	6.4%	68.7%	91.4%	125.5%
5														
6	Energy													
7	Power Generation Fuel	5,543,690	2,876,726	51.9%	412,514	7.4%	3,583,181	1,774,736	49.5%	218,956	6.1%	54.7%	62.1%	88.4%
8	Other Power Supply Expense	62,964,670	32,673,564	51.9%	4,685,296	7.4%	77,621,936	37,795,957	48.7%	4,743,210	6.1%	-18.9%	-13.6%	-1.2%
9	Subtotal	68,508,360	35,550,290	51.9%	5,097,810	7.4%	81,205,117	39,570,693	48.7%	4,962,166	6.1%	-15.6%	-10.2%	2.7%
10														
11	Distribution													
12	Distribution Plant	350,880,250	221,990,904	63.3%	35,589,734	10.1%	325,339,574	169,946,505	52.2%	25,634,537	7.9%	7.9%	30.6%	38.8%
13	Accum Depr	203,151,309	131,179,705	64.6%	17,260,152	8.5%	176,552,638	91,407,447	51.8%	13,308,571	7.5%	15.1%	43.5%	29.7%
14	Net Plant	147,728,941	90,811,199	61.5%	18,329,582	12.4%	148,786,936	78,539,058	52.8%	12,325,966	8.3%	-0.7%	15.6%	48.7%
15														
16	Transmission by Others													
17	PPFAC Eligible	9,014,026	4,677,549	51.9%	670,747	7.4%	8,853,006	4,310,738	48.7%	540,977	6.1%	1.8%	8.5%	24.0%
18	Non PPFAC Eligible	14,531,456	8,787,564	60.5%	1,250,088	8.6%	10,279,126	5,479,378	53.3%	661,355	6.4%	41.4%	60.4%	89.0%
19	Subtotal	23,545,482	13,465,113	57.2%	1,920,835	8.2%	19,132,132	9,790,116	51.2%	1,202,332	6.3%	23.1%	37.5%	59.8%

Exhibit HS-3

		A	B	C	D	E	F	G	H	I
LINE	CCoSS Comparisons	Total	Residential	Small General Service	Medium/Large General Service	Large General Service	Large Power Service	Large Power Service	Mining	Lighting
	2012									
1	Total Ratebase	$216,574,773	$114,992,540	$13,819,293		$51,716,825	$18,071,308		$16,834,066	$1,140,741
2	% of Ratebase		53.1%	6.4%		23.9%	8.3%		7.8%	0.5%
3										
4	Total Electric Revenue from Sales	$162,190,518	$80,572,595	$11,537,036		$47,795,940	$14,754,841		$6,914,746	$615,360
5	% of Electric Sales		49.7%	7.1%		29.5%	9.1%		4.3%	0.4%
6										
7	Total Operating Expenses	$149,373,340	$76,923,966	$10,619,009		$38,227,069	$13,953,652		$9,058,995	$590,649
8	% of Operating Expenses		51.5%	7.1%		25.6%	9.3%		6.1%	0.4%
9										
10	Operating Income	$12,817,178	$3,648,629	$918,027		$9,568,871	$801,189		-$2,144,249	$24,711
11										
12	Rate of Return	5.92%	3.17%	6.64%		18.50%	4.43%		-12.74%	2.17%
13	UROR		0.536	1.122		3.126	0.749		-2.152	0.366
14										
15	kWh Sales	1,818,398,842	848,875,174	96,989,850		513,288,747	223,497,643		133,074,196	2,673,232
16	% of Sales		46.7%	5.3%		28.2%	12.3%		7.3%	0.1%
17										
18	Test Year UNAdjusted Customers	91,507	79,493	7,962		1,884	21		2	2,144
19										
20										
21	2014									
22	Total Ratebase	$272,013,129	$166,482,331	$27,414,831	$70,946,559			$5,737,904		$1,431,504
23	% of Ratebase		61.2%	10.1%	26.1%			2.1%		0.5%
24										
25	Total Electric Revenue from Sales	$147,176,645	$73,653,026	$11,905,151	$53,699,953			$7,375,505		$543,010
26	% of Electric Sales		50.0%	8.1%	36.5%			5.0%		0.4%
27										
28	Total Operating Expenses	$140,891,931	$80,118,247	$12,183,739	$42,331,725			$5,771,597		$486,623
29	% of Operating Expenses		56.9%	8.6%	30.0%			4.1%		0.3%
30										
31	Operating Income	$6,284,714	-$6,465,221	-$278,588	$11,368,228			$1,603,908		$56,387
32										
33	Rate of Return	2.31%	-3.88%	-1.02%	16.02%			27.95%		3.94%
34	UROR		-1.681	-0.440	6.935			12.098		1.705
35										
36	kWh Sales	1,600,809,166	823,953,185	118,683,796	562,579,661			92,765,274		2,827,250
37	% of Sales		51.5%	7.4%	35.1%			5.8%		0.2%
38										
39	Test Year Adjusted Customers	95,144	82,607	8,758	1,387			4		2,388
40										
41										
42	2014 vs 2012									
43	Increase in Class Ratebase	25.6%	44.8%	98.4%						25.5%
44										
45	Increase in Electric Revenue	-9.3%	-8.6%	3.2%						-11.8%
46										
47	Increase in Operating Expenses	-5.68%	4.15%	14.74%						-17.61%
48										
49	Increase in kWh Sales	-12.0%	-2.9%	22.4%						5.8%
50										
51	Increase in Customers	4.0%	3.9%	10.0%						11.4%

Exhibit HS-4

LINE		TOTAL (A)	RESIDENTIAL SERVICE (B)	SMALL GENERAL (C)	MEDIUM/LARGE GENERAL (E)	LARGE POWER (F)	LIGHTING (H)
1	**75% of RES SGS to UROR = 1.00**						
2	Incremental Revenue	$18,128,000	$15,844,500	$1,992,750	$253,386	$34,802	$2,562
3	Rate of Return on Rate Base	6.92%	3.75%	4.49%	13.97%	24.22%	3.20%
4	UROR	1.00	0.54	0.65	2.02	3.50	0.46
5	% Incr compared to Revenue From Present Sales	12.32%	21.51%	16.74%	0.47%	0.47%	0.47%
6	% of the Total Increase	100.0%	87.4%	11.0%	1.4%	0.2%	0.0%
7							
8							
9	**67.7% of RES SGS to UROR = 1.00**						
10	Incremental Revenue	$18,128,000	$14,084,000	$1,771,333	$1,980,609	$272,030	$20,028
11	Rate of Return on Rate Base	6.92%	2.69%	3.69%	16.41%	28.35%	4.42%
12	UROR	1.00	0.39	0.53	2.37	4.10	0.64
13	% Incr compared to Revenue From Present Sales	12.32%	19.12%	14.88%	3.69%	3.69%	3.69%
14	% of the Total Increase	100.0%	77.7%	9.8%	10.9%	1.5%	0.1%
15							
16							
17	**60% of RES SGS to UROR = 1.00**						
18	Incremental Revenue	$18,128,000	$12,675,600	$1,594,200	$3,362,388	$461,812	$34,000
19	Rate of Return on Rate Base	6.92%	1.84%	3.04%	18.36%	31.66%	5.40%
20	UROR	1.00	0.27	0.44	2.65	4.58	0.78
21	% Incr compared to Revenue From Present Sales	12.32%	17.21%	13.39%	6.26%	6.26%	6.26%
22	% of the Total Increase	100.0%	69.9%	8.8%	18.5%	2.5%	0.2%
23							
24							
25	**50% of RES SGS to UROR = 1.00**						
26	Incremental Revenue	$18,128,000	$10,563,000	$1,328,500	$5,435,055	$746,486	$54,959
27	Rate of Return on Rate Base	6.92%	0.57%	2.07%	21.28%	36.62%	6.86%
28	UROR	1.00	0.08	0.30	3.08	5.29	0.99
29	% Incr compared to Revenue From Present Sales	12.32%	14.34%	11.16%	10.12%	10.12%	10.12%
30	% of the Total Increase	100.0%	58.3%	7.3%	30.0%	4.1%	0.3%
31							
32							
33	**All UROR equals 1.00**						
34	Incremental Revenue	$18,128,000	$21,126,000	$2,657,000	-$4,752,900	-$957,900	$55,800
35	Rate of Return on Rate Base	6.92%	6.92%	6.92%	6.92%	6.92%	6.92%
36	UROR	1.00	1.00	1.00	1.00	1.00	1.00
37	% Incr compared to Revenue From Present Sales	12.32%	28.68%	22.32%	-8.85%	-12.99%	10.28%
38	% of the Total Increase	100.0%	116.5%	14.7%	-26.2%	-5.3%	0.3%
39							
40							
41	**Equal Percentage**						
42	Incremental Revenue	$18,128,000	$9,071,970	$1,466,378	$6,614,315	$908,454	$66,883
43	Rate of Return on Rate Base	6.92%	-0.32%	2.57%	22.94%	39.44%	7.69%
44	UROR	1.00	-0.05	0.37	3.32	5.70	1.11
45	% Incr compared to Revenue From Present Sales	12.32%	12.32%	12.32%	12.32%	12.32%	12.32%
46	% of the Total Increase	100.0%	50.0%	8.1%	36.5%	5.0%	0.4%
47							
48							
49	**$18.128 million spread by UNS allocation**						
50	Incremental Revenue	$18,128,000	$16,524,739	$2,141,763	$21,178	-$620,445	$60,765
51	Rate of Return on Rate Base	6.92%	4.15%	5.04%	13.65%	12.80%	7.27%
52	UROR	1.00	0.60	0.73	1.97	1.85	1.05
53	% Incr compared to Revenue From Present Sales	12.32%	22.44%	17.99%	0.04%	-8.41%	11.19%
54	% of the Total Increase	100.0%	91.2%	11.8%	0.1%	-3.4%	0.3%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

Exhibit HS-5

RESIDENTIAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)			Customer Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
		0-400	401-1,000	1,000+	$10.00	$0.01930	$0.03435	$0.03850	$0.001140	$0.064510	-$0.002139	
Xsmall	111	111	0	0	$10.00	$2.14	$0.00	$0.00	$0.13	$7.16	-$0.24	$19.19
Small	330	330	0	0	$10.00	$6.37	$0.00	$0.00	$0.38	$21.29	-$0.71	$37.33
Medium	664	400	264	0	$10.00	$7.72	$9.07	$0.00	$0.76	$42.83	-$1.42	$68.96
Large	1,144	400	600	144	$10.00	$7.72	$20.61	$5.54	$1.30	$73.80	-$2.45	$116.53
Xlarge	2,162	400	600	1,162	$10.00	$7.72	$20.61	$44.74	$2.46	$139.47	-$4.63	$220.37
Mean	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
Sum	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20
Win	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48
Annual												$1,018.12

BILL IMPACTS - STAFF PROPOSED RATES

	Total kWh	Delivery (kWh)			Customer Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$15.00	$0.02638	$0.04143	$0.04558	$0.000000	$0.053288	$0.000000			
		400	600	1000										
Xsmall	111	111	0	0	$15.00	$2.93	$0.00	$0.00	$0.00	$5.91	$0.00	$23.84	$4.64	24.2%
Small	330	330	0	0	$15.00	$8.71	$0.00	$0.00	$0.00	$17.59	$0.00	$41.30	$3.96	10.6%
Medium	664	400	264	0	$15.00	$10.55	$10.94	$0.00	$0.00	$35.38	$0.00	$71.87	$2.91	4.2%
Large	1,144	400	600	144	$15.00	$10.55	$24.86	$6.56	$0.00	$60.96	$0.00	$117.94	$1.41	1.2%
Xlarge	2,162	400	600	1,162	$15.00	$10.55	$24.86	$52.97	$0.00	$115.21	$0.00	$218.59	-$1.78	-0.8%
Mean	830	400	430	0	$15.00	$10.55	$17.80	$0.00	$0.00	$44.20	$0.00	$87.55	$2.39	2.8%
Sum	983	400	583	0	$15.00	$10.55	$24.17	$0.00	$0.00	$52.40	$0.00	$102.12	$1.92	1.9%
Win	669	400	269	0	$15.00	$10.55	$11.16	$0.00	$0.00	$35.67	$0.00	$72.39	$2.90	4.2%
Annual												$1,047.06	$28.94	2.8%

BILL IMPACTS - UNS PROPOSED RATES

	Total kWh	Delivery (kWh)			Customer Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$20.00	$0.03081	$0.05081	$0.05081	$0.000000	$0.049260	$0.000000			
		400	600	1000										
Xsmall	111	111	0	0	$20.00	$3.42	$0.00	$0.00	$0.00	$5.47	$0.00	$28.89	$9.70	50.5%
Small	330	330	0	0	$20.00	$10.17	$0.00	$0.00	$0.00	$16.26	$0.00	$46.43	$9.09	24.4%
Medium	664	400	264	0	$20.00	$12.32	$13.41	$0.00	$0.00	$32.71	$0.00	$78.45	$9.49	13.8%
Large	1,144	400	600	144	$20.00	$12.32	$30.49	$7.32	$0.00	$56.35	$0.00	$126.48	$9.95	8.5%
Xlarge	2,162	400	600	1,162	$20.00	$12.32	$30.49	$59.04	$0.00	$106.50	$0.00	$228.35	$7.98	3.6%
Mean	830	400	430	0	$20.00	$12.32	$21.82	$0.00	$0.00	$40.86	$0.00	$95.01	$9.85	11.6%
Sum	983	400	583	0	$20.00	$12.32	$29.64	$0.00	$0.00	$48.44	$0.00	$110.40	$10.20	10.2%
Win	669	400	269	0	$20.00	$12.32	$13.69	$0.00	$0.00	$32.98	$0.00	$78.99	$9.51	13.7%
Annual												$1,136.37	$118.26	11.6%

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	)	DOCKET NO. E-04204A-15-0142

DIRECT RATE DESIGN

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST MANAGER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 9, 2015

TABLE OF CONTENTS

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This testimony addresses UNSE's proposed modifications to its Purchased Power and Fuel Adjustment Clause ("PPFAC").

Staff's recommendations are as follows:

1. The PPFAC rate should remain as a dollar per kWh rate.

2. The rate band should remain at 0.83 percent.

3. The proposed Base Rate Annual Adjustment should not be approved.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony concerning power supply, Gila River Power Plant Unit 3, and base cost of fuel and purchased power for UNS Electric, Inc. ("UNSE" or "Company").

Q. What is subject matter of this rate design testimony?

A. This testimony will address UNSE's proposed modifications to its Purchased Power and Fuel Adjustment Clause ("PPFAC").

PROPOSED MODIFICATIONS TO PPFAC

Q. What is the purpose of a PPFAC?

A. The purpose of a PPFAC is to track changes in the costs of obtaining power supplies. The costs of obtaining power supplies included in the base rates approved by the Commission in a rate case are compared to actual power supply costs incurred after the rate case. A PPFAC rate is used to bill or refund to customers the difference in costs.

Q. How does UNSE's PPFAC work?

A. The PPFAC Plan of Administration ("POA") describes how the PPFAC works. UNSE's PPFAC uses a historical 12-month rolling average of actual fuel, purchased power, and purchased transmission costs to reset the PPFAC rate each month without Commission approval. The actual costs are compared to the Average Base Cost of Fuel and Purchased Power approved in UNSE's last rate case.

Decision No. 74235 approved $0.05706 per kilowatt-hour ("kWh") as the Average Base Cost of Fuel and Purchased Power. As of December 1, 2015, the PPFAC rate was negative $0.000978 per kWh.

The change in the PPFAC rate is banded so that the new monthly PPFAC rate cannot increase or decrease the preceding month's Total Average Retail Fuel and Purchased Power Rate (the average base cost of fuel and purchased power plus the preceding month's PPFAC rate) by more than 0.83 percent.

Any over- or under-recovery of actual costs is recorded in the PPFAC bank balance, with interest. If the bank balance becomes over-collected by more than $10 million, UNSE must file for a PPFAC rate adjustment within 45 days or contact Staff to discuss why a rate adjustment is not necessary at that time. If the bank balance is under-collected, UNSE has the right to file an application with the Commission requesting a surcharge.

Q. What modifications has UNSE proposed for its PPFAC?

A. UNSE witness Craig A. Jones (Direct Testimony, pages 72-73, and Exhibit CAJ-5) has proposed the following modifications to the PPFAC:

1. The monthly PPFAC rate would be set as a percentage to be applied to the base cost of fuel and purchased power embedded in base rates for each rate class instead of as a dollar per kWh rate billed to all customers;
2. The rate band would be increased from 0.83 percent per month to 1 percent per month; and
3. A Base Rate Annual Adjustment would be added.

Q. Please describe UNSE's proposal to apply the PPFAC rate as a percentage.

A. As proposed by UNSE in this rate case, each customer class rate schedule has an unbundled rate component titled Base Power. Time-of-use rate schedules have separate Base Power rates for on-peak and off-peak times. Rate schedules with seasonal rates have additional Base Power rates. UNSE is proposing that the PPFAC rate be set as a percentage to be applied to the Base Power component(s) of each rate schedule. Currently, the PPFAC rate is simply a dollar per kWh rate that is multiplied by the monthly kWh used by each customer.

Q. Does Staff agree with UNSE's proposed percentage PPFAC rate?

A. No. It adds a great amount of complexity that is not needed, and it may shift costs among customer classes.

Q. Please describe UNSE's proposal to increase the rate band from 0.83 percent per month to 1 percent per month.

A. As described above, the band prevents the PPFAC rate from having very large increases or decreases. Mr. Jones (Direct Testimony, page72) states that the rate band should be increased because of the reduction in fuel and purchased power expenses caused by the purchase of Gila River and because of low commodity prices implied in forward markets.

Q. Does Staff agree with UNSE's proposed increase in the rate band?

A. No. A reduction in costs does not justify an increase in the rate band. The monthly 0.83 percent rate band prevents customers from experiencing more than a 10 percent increase over a year without Commission approval.

Q. What is Staff's recommendation regarding the rate band?

A. Staff recommends that the rate band remain at 0.83 percent.

Q. Please describe UNSE's proposed Base Rate Annual Adjustment.

A. Mr. Jones (Direct Testimony, page 73) states that the Base Rate Annual Adjustment is intended to improve the correlation between actual base rate collections and the approved base rate. He states that the variances between actual and approved base rate collections are driven by changing customer behavior.

Q. What is Staff's recommendation regarding the proposed Base Rate Annual Adjustment?

A. Staff recommends that the Base Rate Annual Adjustment not be approved, because the purpose of the PPFAC is to track fuel and purchased power costs, not to adjust for variations in base rate revenues due to changing customer behavior.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. Staff's recommendations are as follows:

1. The PPFAC rate should remain as a dollar per kWh rate.
2. The rate band should remain at 0.83 percent.
3. The proposed Base Rate Annual Adjustment should not be approved.

Q. Does this conclude your direct rate design testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. 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 UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

DIRECT

RATE DESIGN

TESTIMONY

OF

ERIC VAN EPPS

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 9, 2015

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-15-0142

This testimony addresses proposed Rate Design recommendations for the Transmission Cost Adjustor ("TCA"), Demand-side Management ("DSM"), and Renewable Energy Standard and Tariff ("REST") adjustment mechanisms.

UNS Electric, Inc. ("UNSE") has not proposed any significant changes to the aforementioned adjustors other than an adjustment to how the CARES Program affects the DSM adjustor.

Staff recommends that UNSE update its TCA Plan of Administration ("POA") and file POA's for the existing DSM and REST adjustors.

INTRODUCTION

Please state your name, occupation, and business address.

A. My name is Eric Van Epps. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I provide recommendations to the Commission on matters involving electric and gas utilities. I also perform studies on ancillary issues pertaining to matters in and around the electric utility industry. I have been employed with the Commission for three years.

Q. Have you previously filed testimony in this docket?

A. Yes, I filed direct testimony concerning the pro-forma adjustments to the Transmission Cost Adjustor ("TCA"), Demand-side Management ("DSM") and Renewable Energy Standard and Tariff ("REST") for UNS Electric, Inc. ("UNSE" or "Company"). This rate design testimony addresses other aspects of the adjustors.

Q. Have you reviewed the testimony submitted by the Company in this case?

A. Yes. I reviewed the testimony of Company witness, Mr. Craig A. Jones. Mr. Jones has not proposed any changes to the TCA or REST adjustor. Mr. Jones has proposed a change to the DSM Surcharge Rate Schedule (Rider R-2) to reflect his proposed change to the CARES program which would affect the DSM adjustor. The proposed change to the CARES program would no longer exempt CARES customers from paying the DSM Surcharge.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize your direct rate design recommendations.

A. My direct rate design recommendations are as follows, Staff recommends that UNSE file Plan(s) of Administration ("POA") for both the DSM and REST adjustors. Further, Staff recommends that UNSE look at the POA of Tucson Electric Power Company ("TEP") and provide draft POAs for both the aforementioned adjustors in rebuttal testimony. Further, Staff recommends that UNSE update its TCA POA, consistent with the discussions it had with Staff and provide a draft in its rebuttal testimony.

TRANSMISSION COST ADJUSTOR

Q. Are there changes the Company wishes to make to the TCA POA?

A. Yes, the Company has indicated in a data response that it wishes to make changes to its existing TCA POA that reflect recommendations from Staff after the filing date of its rate case.

Q. Has the Company provided Staff with its proposed changes to the TCA?

A. No, other than the initial conversation with Staff regarding changes to the TCA, while processing the Company's Annual TCA filing, Staff has not been provided the Company's proposed changes.

Q. How does Staff recommend the Company proceed?

A. Staff recommends that the Company clearly outline why it wishes to change its existing TCA, and provide a draft TCA POA in rebuttal testimony for Staff's review.

DEMAND-SIDE MANAGEMENT

Q. Has the Company requested any changes to its current DSM adjustor?

A. Yes, the Company has requested a change to the DSM Surcharge Rate Schedule (Rider R-2) to reflect a proposed change to the CARES program which would affect the DSM adjustor. The proposed change to the CARES program would no longer exempt CARES customers from paying the DSM Surcharge.

Q. Has the CARES Program been addressed in other congruent testimony?

A. Yes, Howard Solganick has addressed the Company's proposed changes to the CARES Program in his rate design testimony.

Q. Are there any other issues with the DSM adjustor that staff wishes to address?

A. Yes, currently UNSE does not have a POA on file for its DSM adjustor.

Q. Why is the absence of a DSM POA a concern for Commission Staff?

A. The DSM adjustor is a complex adjustor mechanism with functions that should be outlined in a POA so that current and future staff at both the Company and Commission can be in agreement as to how the Adjustor is intended to operate.

Q. Should the Company create a POA for its DSM Adjustor?

A. Yes, Staff recommends that the Company provide in its rebuttal testimony a draft DSM POA for Staff review. Further Staff requests UNSE address the scope and type of costs eligible for recovery in its draft POA.

RENEWABLE ENERGY STANDARD AND TARIFF

Q. Has the Company requested any changes to its current REST adjustor?

A. No, adjustments to the REST adjustor are typically addressed in the Company's Annual REST Filing.

Q. Are there any other issues with the REST adjustor that staff wishes to address?

A. Yes, currently UNSE does not have a POA on file for its REST adjustor.

Q. Why is the absence of a REST POA a concern for Commission Staff?

A. The REST adjustor is a complex adjustor mechanism with functions that should be outlined in a POA so that current and future staff at both the Company and Commission can be in agreement as to how the Adjustor is intended to operate.

Q. Should the Company create a POA for its REST Adjustor?

A. Yes, Staff recommends that the Company provide in its rebuttal testimony a draft REST POA for Staff review. Further Staff requests UNSE address the scope and type of costs eligible for recovery in its draft POA.

Q. Does this conclude your direct rate design testimony?

A. Yes, it does.