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**BEFORE THE ARIZONA CORPORATION COMMISSION**

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AZ CORP COMMISSION
DOCKET CONTROL

IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION

DOCKET NO. E-00000J-14-0023

**NOTICE OF FILING DIRECT TESTIMONY**

Tucson Electric Power Company and UNS Electric, Inc., through undersigned counsel, submits the Direct Testimony of Carmine Tilghman and H. Edwin Overcast.

RESPECTFULLY SUBMITTED this 25th day of February 2016.

Arizona Corporation Commission
DOCKETED
FEB 25 2016
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# BEFORE THE ARIZONA CORPORATION COMMISSION

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

Direct Testimony of

Carmine A. Tilghman

on Behalf of

Tucson Electric Power Company and UNS Electric, Inc.

February 25, 2016

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**<u>Exhibits:</u>**

Exhibit CT-1 Initial Comments filed in Docket NO. E-00000J-14-0023

## I. Introduction.

**Q. Please state your name and business address.**

A. Carmine Tilghman, 88 East Broadway, Tucson, Arizona 85701

**Q. What is your position with Tucson Electric Power Company ("TEP" or the "Company")?**

A. I am the Senior Director of Energy Supply for Tucson Electric Power Company ("TEP" or "the Company") and UNS Electric ("UNS Electric").

**Q. Please describe your background and work experience.**

A. I served in the United States Navy from 1984–1993 as a Nuclear Reactor Operator in Submarine Service. From 1993-1995, I worked as a Power Plant Operator for the Biosphere II Project in Oracle, Arizona.

I was hired by TEP in 1995 as a Power Plant Operator. In 1996, I moved into TEP's Wholesale Marketing Department where I held several positions in Energy Trading, Marketing, Project Management, and Scheduling before being promoted to Supervisor/Manager in 2003. From 2003-2008, I held supervisory positions in Trading, Scheduling, and Procurement before taking over Utility Scale Renewable Energy Development in 2008.

In 2010, I took over all aspects of renewable energy development for both TEP and UNS Electric, Inc. In my current position, I am responsible for the renewable resources and renewable resource programs for the Companies, including compliance with the Arizona Corporation Commission's ("Commission") Renewable Energy Standard and Tariff Rules ("REST Rules") (A.A.C. R14-2-1801 through R14-2-1818)). In 2013, I added oversight of the Wholesale Marketing department to my duties, and in 2014 was promoted to Senior Director.

I received my Bachelor of Science in Business Management from the University of Phoenix in 2000 and Master of Business Administration from the University of Phoenix in 2002.

**Q. What is the purpose of your Direct Testimony?**

A. My testimony will focus on (i) TEP and UNSE's (collectively the "Companies") position regarding the value of distributed solar, (ii) methods on how to calculate that value, (iii) a comparison of DG solar to utility-scale solar, and (iv) specific issues raised by Commissioners through docketed letters.

**Q. What do the Companies hope to see as an outcome of this Value of Solar (VOS) docket?**

A. The Companies would like to see a clear definition and resolution to the following issues:

1. Clearly separating the utility's cost of service from any societal and forward looking benefits that the Commission deems are appropriate.
2. Identify the necessary revenue streams to fairly compensate both the utility and the customer.
3. Establish an appropriate mechanism or model that provides the correct price signals to allow the market to respond to customer needs and supports the advancement and adoption of new technologies.

**Q. Do the Companies have some general thoughts on the costs and benefits of distributed generation?**

A. Yes. We submitted initial comments in this docket in February of 2014. Those comments provided an overview of the costs and benefits in the context of rate making and providing economical service to our customers. A copy of those comments are attached as **Exhibit CT-1**.

## II. <u>Companies' Current Rate Case Proposals.</u>

**Q. Does either TEP or UNSE have a proposal before the Commission specifically related to the value of a customer's distributed generation ("DG") facility?**

A. Yes. Both companies have submitted proposals to make changes to the current net energy metering ("NEM") rules in their respective rate cases. The proposed changes to the Net Metering tariff are two-fold:

1. A request for a new net metering tariff that provides monthly bill credits at a Renewable Credit Rate ("RCR") for excess energy produced and pushed onto the grid from a customer's solar system. The RCR is equivalent to the most recent utility scale renewable energy purchased power agreement connected to either of the Companies' distribution system.

2. A partial waiver of the Net Metering Rules to eliminate the "roll over" of excess generation to offset future usage, as is currently prescribed in A.A.C. R14-2-2306.

**Q. What is the basis for the Companies' proposed NEM changes?**

A. The current NEM rules and policies were established to provide an incentive to customers in the early years of renewable energy development, particularly solar DG due to its initial high costs. However, the rapid technological advancement of solar and subsequent decline of prices, as well as the availability of generous federal tax credits for solar DG systems, have led to a dramatic increase in DG solar installations. While the technology has advanced and prices have declined, the various rate subsidies (including NEM) have not been addressed. This has led to a disconnect between the appropriate price signals for the market and technology adoption; a significant cost shift from solar customers to non-solar customers due to antiquated rate design structures; and design inefficiencies resulting in the promotion of more expensive technologies.

Specifically, retail NEM programs and policies do not promote the adoption of DG in the most cost-effective manner, which has led to the installation of systems that are designed to result in the maximum annual production to offset charges for kWh consumption from the utility's system rather than promote demand reduction and system-wide benefits. Additionally, the Company believes that it is no longer appropriate to pay full retail credit for DG solar when a utility-scale solar facility on the same distribution system can be built or purchased for approximately half the cost and that provides the same green energy with the same environmental attributes. The benefits and value of utility-scale solar production on the distribution system is nearly identical to DG. When considering the potential for increased production and lower costs, it can be argued that these benefits are superior to DG. And while utility-scale developers have consistently lowered their costs to reflect the maturity of the industry and advancement of solar development, and have passed those savings on to utilities and customers, the solar DG industry has fought to preserve full retail net metering. The Company's position on this issue has been consistent. *A solar DG customer who pushes energy back onto the grid should be compensated at the wholesale rate for solar energy.*

The second component of the Company's proposal is to eliminate the month to month banking of retail energy credits. This policy, along with a full retail rate credit for excess generation, drives many solar providers to design DG systems to produce as much energy as possible in the non-summer months in order to "get through" the summer months without having to pay for the energy generated and delivered by the utility that was consumed by the customer. The value of energy produced by a solar system between October and May ***is not*** equivalent to the energy consumed by the customer during the summer peak demand months of June through September.

**Q. Are the Companies proposing that the above changes to NEM be included in a VOS calculation?**

A. Not necessarily. If the Commission wants to address all of the issues regarding the value of solar and would like to assign individual values to societal and economic benefits, then it will require more than a simple change to NEM policies. The Companies' NEM proposals only address a portion of the value of solar as it relates to current rate design structures, pricing signals, and excess energy under the traditional cost of service rate structure. If simplicity is the goal in evaluating DG and its benefits, then choosing the Companies' proposed use of wholesale market price of solar transactions as the "value" is an easily attainable, reasonable and objective proxy.

However, if the Commission decides to value solar relative to known and measurable quantities of variable cost savings (rate design principles), along with providing monetary consideration for forward looking and societal benefits (resource planning principles), then it will require a more comprehensive valuation model.

## III. <u>The Companies' Responses to Chairman Little's December 22, 2015 Letter, Commissioner Burns' February 8, 2016 letter, and Commissioner Stump's February 19, 2016 letter.</u>

**Q. Chairman Little's letter indicates that this docket should seek to develop a methodology that would inform future proceedings as to how the value and cost of solar should be evaluated and determined as part of a rate case. Do the Companies have a recommendation for a more comprehensive VOS model?**

A. Yes. The Companies propose using a model similar to the one being developed by the Utah Public Service Commission (Docket No. 14-035-114). This model effectively uses two cost of service models to determine the real impact to rates under the cost of service model, and then allows the Commission to address forward looking and resource planning components separately.

**Q. Please describe the Utah model in more detail.**

A. Utah is developing a model that consists of two components:

1. Known and measurable costs and benefits currently collected through rates (rate setting process)
   - a. Fuel offset/avoided energy
   - b. Losses (energy/line)
   - c. Administration and integration costs
   - d. Ancillary services
2. External, societal, and future benefits for which a separate revenue stream must be identified (resource planning process)
   - a. Avoided generation capacity
   - b. Avoided transmission & distribution capacity
   - c. Avoided emission costs ($CO_2$, $SO_2$, $NOX$, etc.)

d. Fuel hedging costs/savings

e. Additional costs associated with operational compliance – integration costs

f. Societal benefits

This model uses two cost of service studies: a Counter factual Cost of Service Study ("CFCOS") that assumes away the existence of NEM customers' power generation (where the Company supplies all customer load as if there was no solar DG); and an Actual Cost of Service Study ("ACOS"), which shows actual cost of service inclusive of existing NEM customers (meaning the Company supplies only the "net" load of a DG customer). This allows the Commission to determine if there is a cost or benefit that should be applied to the DG customer based on known and measurable costs and benefits currently collected through rates.

Additionally, this model then defines the more subjective costs and savings associated with external, societal, and future benefits for which a separate revenue stream must be identified. The Commission would have the opportunity and flexibility to set these additional cost and savings values at their discretion in the Company's rate case, based on data provided through the Company's Integrated Resource Plan, Stakeholder input, and other factors. Cumulatively, these two values would provide the basis for compensation for the DG solar customer.

**Q. What are some of the other considerations and assumptions made in the model described above?**

A. There were several considerations and assumptions made in the Utah process that include:

1. The respective utility has all necessary meter data to provide meaningful data.

2. Using multiple COS studies would provide impacts of NEM at system, state, and customer levels.

3. The Counter factual and Actual Cost of Service studies should be commensurate with a test year, which is consistent with the ratemaking concept of utilizing short-term study periods (test year) because they would be, in effect, used to set rates.

4. Actual COS would capture cost impacts associated with excess energy.

5. Excess energy does not have price or value assigned to it in ACOS, other than as recognized in net power cost analysis.

6. Segregates NEM and non-NEM customers into two classes for purposes of determining cost allocation based on their respective usage characteristics, solving cost causation and mitigating subsidization.

7. Does not establish a new rate class, only segregates them for purposes of analysis

**Q. How would variations of cost and value based on locational and production benefits be accounted for?**

A. The utilization of appropriate rate design structures, including TOU pricing, will compensate for production benefits. Locational benefits and costs within a distribution system may be able to be identified through the use of more detailed system modeling; however, at this time the Company believes it is unnecessary to develop such a complex valuation model.

**Q. How were the value and cost of solar considered in the development of the current net metering tariffs?**

A. Due to a lack of quantifiable costs and benefits at the time the current tariffs were created nearly a decade ago, and a political desire to implement more renewable generation through NEM policies, the concept of retail net metering was used for its ease of implementation. Indeed, the Commission order directing the preparation of the net metering rules expressly stated that "Net metering provides a financial incentive to encourage the installation of DG, especially renewable resources." Decision No. 69877 (August 28, 2007). This concept was often referred to as a "rough justice" based on current solar prices, actual cost savings, and unquantifiable societal and resource planning benefits.

**Q. Over the past several years the cost of PV panels has declined significantly. Does the declining cost of panels affect the value proposition? If so, how?**

A. Yes. As the cost of panels and installed systems came down, the Commission lowered the ratepayer-funded up-front and performance-based incentive payments in an attempt to coincide with the cost reduction. Eventually the ratepayer-funded up-front and performance-based incentive payments were reduced to zero. With continuing decreases in equipment and installation costs and the remaining Federal and State tax incentives, which are fixed, the cost/benefit ratio continues to improve for the individual customer (purchased system) and the leasing entities (leased system). Unfortunately, due to the current structure of NEM (and current rate design), this is also increasing the cost burden on non-DG customers.

**Q. Is it appropriate to factor the cost of panels into the reimbursement rate for net metering? If so, how?**

A. No. A customer's choice to invest in solar should be evaluated using the same economic premise as a non-renewable generator (such as a gas generator), or other energy efficiency measures (cost of a more efficient air conditioner or heater, upgraded windows, etc.). In short, the cost of the measure should be applied to the expected savings and whether or not the purchase makes economic sense.

The issue is not in the procurement of the system, but in the economic signals sent to the customer through the determination of its value. There should be no more basis for reimbursing the cost of the panels than reimbursing a customer for a gas generator to off-set a demand charge.

**Q. Does the cost and value of DG solar vary based on the specific customer location? Should this variability be reflected in rates?**

A. There are good arguments to the locational value of both utility-scale solar and DG solar, and this value will be more easily defined as penetration levels continue to rise. However, this type of granularity is overly complex, subject to variability and difficult to establish at this time. The infrastructure necessary to establish locational pricing inside a distribution system is several years away, and does not represent the most cost-effective use of the utilities' capital.

Additionally, other aspects of locational pricing must be considered. Questions such as: a.) whether the locational pricing will be based on real-time flows and constantly changing for all customers; b.) whether a customer's pricing will be fixed for a period of time depending on their position in the queue; c.) if pricing is to be fixed for a period, how long and how often is it to be reevaluated; d.) if pricing becomes negative, will that cost be shared by existing DG customers; e.) if upgrades are required to a feeder or substation due to excessive DG, will those costs be borne by those users or all users?

**Q. How does the cost and value of DG solar vary based on the orientation of the panels? How would the installation of single or dual access trackers change the output or efficiency of the DG solar system? Should this variability be reflected in rates?**

A. Cost and value are specific to the entity in question. For example, it is well known that a traditional unshaded, southern facing system with a 20-32 degree tilt (located in TEP's service territory) will have the highest annual production of kWh. As a result, the value to the customer is highest; however, the value to the utility is diminished because that system provides fewer grid benefits than systems of other orientations - for example, it does not generate as much electricity later in the afternoon when demand on the system is higher. The cost of the systems will be approximately the same; but the "value" varies based on specifications unique to each installation and perspective.

A western facing panel provides greater production during summer peaking hours, but at an economic impact to the customer based on current rates and NEM policies. The Commission must determine whose value they are going to consider – the individual customer who purchased the system, the utility looking to reduce their overall system costs, or society in general who wants lower rate impacts with increasing renewable energy?

Solar panels that track the sun's movement increase production but at an added expense – such systems are traditionally not cost-effective on small DG systems. Increased production and lower variability would be reflected in the increased compensation if a "per kWh" method is still employed. Ultimately, time of use pricing would be the most accurate reflection of production and would capture this increased production and efficiency.

**Q. How is the value and cost of DG solar affected when coupled with some type of storage? Should deployment of storage technologies be encouraged? If so, how?**

A. Yes, the deployment of storage should be encouraged. Depending on the particular rate design currently in effect, storage can be used to significantly reduce a customer's peak demand on the grid, thereby reducing the utilities' need for peaking resources (assuming the DG storage reached a "critical mass" quantity that could provide overall system benefits). However, as with most technologies, storage and the ability to provide additional system value (such as reduction in peak generation needs or ancillary services) will be achieved more cost-effectively through large scale storage.

**Q. How does the value and cost of DG solar compare to the value and cost of community scale and utility scale solar? How do the value and costs of DG solar compare to that of wind or other renewable resources? How does the value and cost of DG solar compare to that of energy efficiency?**

A. Economies of scale result in utility-scale or community-scale solar having a 25%-40% reduction in installed price over rooftop solar, even when factoring in other costs such as land and increased interconnection costs.

While the Companies do not have significant wind portfolios, nor do they have any ownership in wind facilities, it is the Companies' understanding that the installed price of wind is less than half of DG solar. However, there is an inherent value in the reduction in losses associated with locally sited solar, while wind resources typically require high voltage transmission to get the resource to the load. There is additional value associated with higher capacity values and increased production from wind that are not associated with solar; however, much of the wind generation is during non-peak hours. It is generally prudent to have an appropriate mix of wind and solar generation that can complement each other while minimizing resource risk.

At this time, the Companies do not believe it is appropriate to compare energy efficiency to DG solar, as it is to some degree an "apples to oranges" comparison. The majority of their similarity lies in the fact that they both reduce kWh production from conventional fuels. Beyond that, many differences between these resources exist.

**Q. How does the intermittent nature of DG solar affect its value and costs? Are there technologies that could reduce the intermittency of DG solar? Should those additional costs result in changes to the value and cost of DG solar? Should an "intermittency factor" be applied to more accurately determine cost and value?**

A. Although the Companies do not see the need to apply an "intermittency factor," they believe that the cost associated with solar intermittency would be reflected using appropriate values and costs. Acknowledging certain characteristics of DG solar and DG customers would sufficiently account for those values and costs, such as the specific demand rates associated with needing to provide full back up services, ancillary charges to reflect the need to maintain or provide voltage and frequency control (which could then be alleviated should a customer self-provide).

As of today, storage is the only technology that reduces the intermittency of solar. However, there are long-term reliability concerns that should be considered. If customer-owned distributed storage technologies were to be implemented and the grid became reliant on them to prevent intermittency, the customer would have to be relied upon to replace or repair the storage technology if it stopped working. Forecasting programs may assist in short-term planning or recognizing pending generation changes, but it does not change or reduce the intermittency.

**Q. To what degree is DG solar energy production coincident with peak demand? Does the cost and value of DG solar vary depending on whether or not energy production is coincident with peak demand? Are there policies that the Commission could consider that address this issue?**

A. DG solar production relative to, and coincident with, peak demand should be looked at two ways: coincidence during annual system peak (summer), which is relative for planning purposes; and coincidence during daily system peak, which is relative to short-term operations.

Relative to the Companies' annual system peak, DG solar has a coincident peak of approximately 30% during the peak hour (which is typically between 4:00 pm – 5:00 pm). While some would argue that this represents a 30% capacity value to the utility, it should be noted that 2 hours after the system peak the Companies' hourly load is still between 90%-93% of the system peak and the solar value is effectively zero. This is an important concept when discussing capacity value and coincident peak production and demand.

With regards to production versus system peak throughout the year, there is no seasonal system peak that coincides when DG solar produces it maximum value at noon. The closest seasonal system peak that would be coincident with DG solar is that of late spring or early fall where the Company has little to no air conditioning or heating load, and there are no defined morning or evening peaks. During this time, system loads tend to rise from morning until afternoon and stay relatively flat until early evening. Unfortunately, these are some of the lowest system peak loads of the year, when there is an abundance of excess generation available and power and gas prices tend to be their lowest. Subsequently, the value of solar during these times is greatly diminished.

During winter peaking months, the Companies experience peak periods in the morning before the sun rises and in the evening after the sun sets. For obvious reasons, the value of solar during the winter is significantly reduced as the generation during the day only serves to offset incremental fuel expense and has zero value relative to capacity.

Although the value of solar relative to the Companies' load varies, these factors can be addressed through appropriate valuation in the cost of service and resource planning process with the appropriate price signals being reflected in the weighted average value.

**Q. Is it possible for DG solar to be more dispatchable? How does the ability to dispatch or the lack of ability to dispatch affect the value and cost of DG solar?**

A. Yes, it is possible for DG solar to be more dispatchable; however, currently it is not practical. The ability for DG solar to be more dispatchable relies on the concept of smart inverters and the ability of the inverter to receive a signal from the utility to respond to set point changes. There are; however, limitations to DG solar dispatchability. For instance, the utility cannot send a "regulation up" signal to provide more energy, as a DG solar system will always produce its maximum value. Even if the utility were to send a curtailment signal – or "regulation down" – the Companies have no idea what the systems' available generation capacity would then be. This is an issue with all intermittent generation resources.

Smart inverters would be able to vary set points to change VAR output of the inverters. This could be useful for distribution system reliability and stability requirements but requires a feeder level control system to manage the appropriate amounts. This also decreases the amount of energy that the system can provide while it is producing VARs. This inability to provide reliable regulation service obviously reduces or diminishes the value of solar relative to a grid operators' ability to manage grid resources. While traditional electric service rates (bundled electric rate) includes these services, they should not be included in the value of solar.

**Q. Will the bi-directional energy flow associated with DG solar require modifications or upgrades to the distribution system? How would the cost of these upgrades be considered when determining the cost and value of DG solar? Would the required upgrades vary based on location and penetration of DG solar? Should the costs for DG installations vary based on these factors?**

A. The bi-directional flow of energy associated with DG solar will require modifications and upgrades to the distribution system. As it is a newly identified phenomenon, the Companies do not have specific measures in place to address any adverse effects as a result of reverse power flow. The bi-directional energy flow on the electrical distribution system varies based on many system electrical parameters that are created by the location and size of the solar system. The problems that are created with bi-directional flows also vary by the time of day and seasonality.

Additional measuring and monitoring equipment will be needed. New methods of modeling the distribution system will need to be developed to model and predict the impacts of a reverse power condition. Upgrades in system automation will be needed to phase balance transformer connections for load and for distributed generation. As reverse power affects the feeder power factor, the placement and sizing of switched distribution capacitor banks is affected as well as distribution transformer sizing. Distribution transformers are specifically designed for stepping down the voltage. Using them to step up the voltage (reverse power flow), unless specified to do so, is not a recommended practice by the manufacturers.

Although the value of solar relative to the Company's load varies, these factors can be addressed through appropriate valuation in the cost of service and resource planning process with the appropriate price signals being reflected in the weighted average value. The amount of remedies that will need to be made are dependent on the size and location of the DG solar installations.

The locational value of DG solar is more easily defined as penetration levels continue to rise. However, this type of granularity would be overly complex and difficult to establish at this time. The needed infrastructure necessary to establish locational pricing inside a distribution system is at least several years away, and does not represent the most cost-effective use of the Companies' capital during this transitional period. Additionally, as previously noted, other aspects of locational pricing must be considered. Questions such as: a) whether the locational pricing will be based on real-time flows and constantly changing for all customers; b) whether a customers' pricing will be fixed for a period of time depending on their position in the queue; c) if pricing is to be fixed for a period, how long and how often is it to be reevaluated; d) if pricing becomes negative, will that cost be shared by existing DG customers; and e) if upgrades are required to a feeder or substation due to excessive DG, will those costs be borne by those users or all users?

**Q. How much should secondary economic impacts of DG solar deployment be considered in the value and cost considerations? Do investments in other types of generation technology have similar, greater or lesser secondary economic impacts? If so, how?**

A. The Utah model previously discussed allows for the Commission to set values for societal benefits, secondary economic impacts, and other subjective benefits. However, these values are difficult to quantify, and it is unlikely that the parties in this proceeding can do much more than agree that they exist. The Companies are not opposed to the

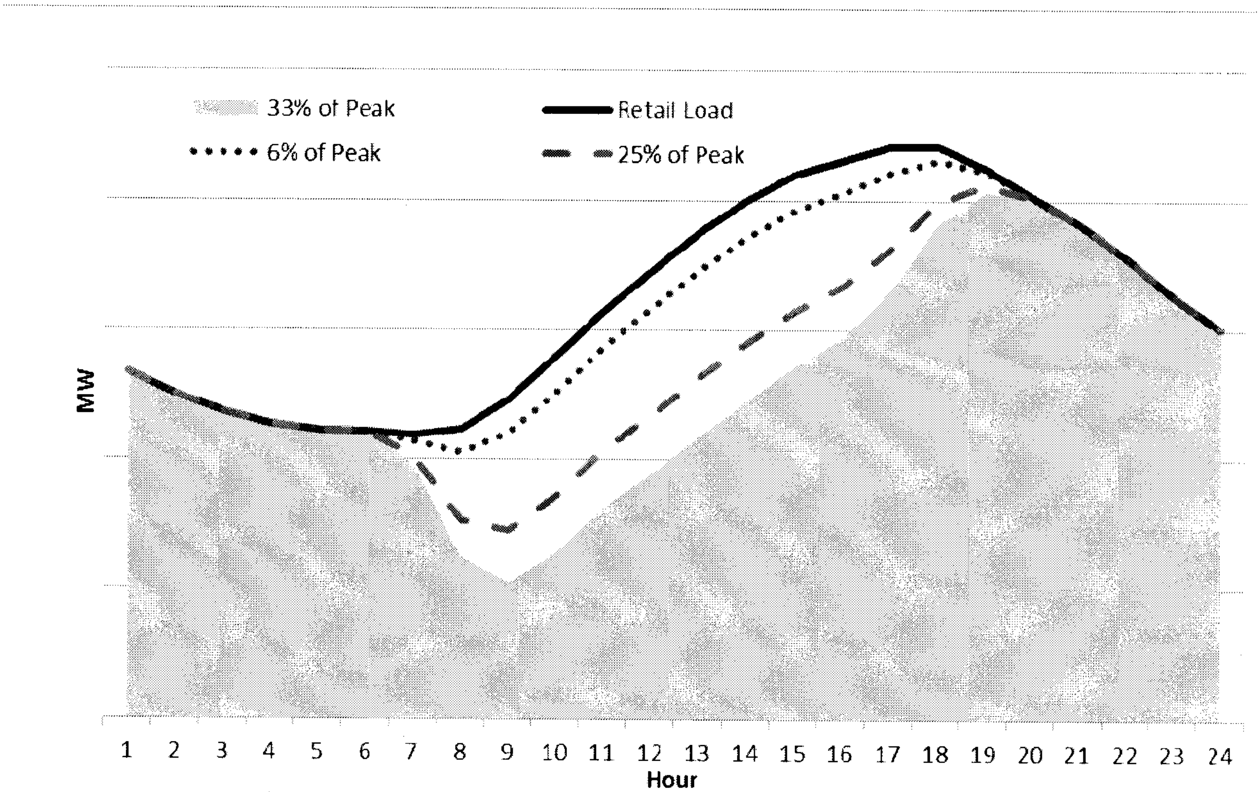
Commission adopting some form of value associated with those benefits, but it questions whether or not this value should be addressed through electric rate design, as current regulatory theory requires costs (and credits) to be based on known and measurable amounts. Instead, it may be more appropriate for State and local governments to provide an economic value or incentive to consumers through some form of tax benefit since society at large receives the greatest benefit from secondary economic impacts.

However, as already stated, this particular model does allow for the determination of societal and secondary benefits values. Should the Commission determine that there is a quantifiable benefit and that individual entities should be compensated through a rate structure, they would also need to determine how the additional revenue needed would be collected and disbursed (to the extent that it is not a direct offset to the current cost of service models with revenues collected through rates).

**Q. How does the value and cost of DG solar change as penetration levels rise? How should this be considered in rate making and resource planning contexts?**

A. The value and cost of DG solar is estimated to change with increased penetration. To determine the value of DG solar, it is imperative to understand its relationship to consumer load. Presumably, most DG solar is sited 'behind the meter' or on customer facilities. The relationship of a DG solar installation at a residential site is assumed to be different than an installation at a commercial site. We can assume that most residential peak load occurs soon after consumers arrive home from work. Commercial peak tends to occur during business hours. This is an important distinction in this discussion because the costs and value impacts to individual feeders and sub-transmission stations can vary due to the blend of residential and commercial customers. This discussion will refer only to the impact on the system in its entirety.

The chart below is a representation of a typical summer load graph and the impacts of increasing DG at various percentages of peak load and the diminishing value of solar as penetration rises.




Historically, electric utilities with predominant air conditioning load set a system peak demand between 4:00 to 5:00 PM on a summer day. DG solar can help reduce this peak but not at the full potential of the DG solar output. DG solar peak production is typically at 12:00 to 1:00 PM. The chart below demonstrates that at 6% (DG installation as a percent of peak retail demand) capacity addition there's an observable reduction of retail peak demand. With increasing DG solar penetration, there's also an observable shift in the load shape. Note the shift between the 6% case and the 25% case. Though there is a noticeable reduction in peak, the time the peak is set is shifting closer to the last diurnal hour of a typical clear-sky summer day (7:00 to 8:00 PM). It is significant then to note that though we introduce a 33% case, the reduction to the newly shifted 7:00 PM peak is minimal. As retail load grows, DG solar will not contribute to the reduction of peak demand beyond 7:00 PM regardless of its penetration.

While it can be argued that DG solar may contribute to reduced losses, to apportioned capacity reductions (generation and transmission), and carbon emission reductions among other benefits, we note from the chart below that other challenges arise. As the sun is rising, electric load stabilizes and begins an ascent toward the peak. However, increased penetration of DG solar creates a rapid net drop in system load. It is at this point that the net reduction in load can create the need for rapid responding generators to regulate the initial steep decline in load followed by an immediate rise. From a resource planning context, with the increasing penetration of solar systems, we must take into consideration the right combination of resources to respond to the variability and intermittency of renewable systems.

**Q. Should the fuel cost savings to the utility associated with DG solar be considered in the value and cost determination? If so, how do we deal with the uncertainty of future fuel prices?**

A. Fuel cost savings are calculated through the production models, which takes into account the weighted average of expected fuel savings per MWh based on the specific technology production profile. In the absence of a real time locational margin pricing ("LMP") mechanism, which is far too complicated to implement at this time, it would be best to reset the fuel rate with each rate case and allow for the recovery of this fuel rate expenditure through the Company's purchased power and fuel ("PPFAC") surcharge. While not as accurate as real-time pricing, it would at least be representative of the average fuel costs, with any under or over collections being applied to the PPFAC, leaving the Company revenue neutral.

**Q. Does the deployment of DG solar result in changes in the need for transmission capacity? If so, how should those changes be included in the value and cost considerations?**

A. If, in fact, DG solar capacity could be relied on dependably (through the use of storage, fuel cells or other similar technology), then it is possible that transmission capacity may be deferred. System growth can dictate the need for upgrades to the transmission system. Scenarios of high DG solar penetration can also result in transmission line capacity deferrals. Peak retail demand typically occurs in the summer months from between 4:00 PM and 5:00 PM. Peak DG solar production occurs during the noon hours of the summer months. The impact of increased DG solar not only reduces peak demand, it consequently also shifts the peak to the later evening hours. The peak shifts ultimately to the last diurnal hour when DG solar is no longer contributing to peak reduction. As DG solar penetration increases, its impact/reduction on peak minimizes; alternatively stated, the capacity value of DG solar diminishes with increased penetration.

DG solar can only defer transmission capacity upgrades in the near-term. As explained above and in question 16, high DG solar penetration shifts the peak. Ultimately, transmission systems are expanded to help serve the growing load and demand; a shifted demand that a high penetration of DG solar can't contribute to. Assigning a capacity value to a potential forward looking capacity deferral is a policy decision that the Commission will need to decide. As "future" benefits are captured in rates, not only would this value need to be determined, but a revenue stream would need to be identified to compensate DG solar customers.

**Q. Does the deployment of DG solar result in changes in the need for distribution capacity? If so, how should those changes be included in the value and cost considerations?**

A. In certain circumstances, extra capacity additions for the distribution system may not be necessary if the same scenarios for DG solar occur every day, i.e. DG is on and producing between 3:30 PM and 6:00 PM as TEP's circuit-peaks occur during these times. TEP's circuit peaks take into account or reflect any DG that is on at the time of our circuit's peaks. However, an overload may not automatically justify a new capital project. TEP will look at the number of hours a circuit is overloaded in a summer, consecutive hours it's overloaded, and what sections of overhead or underground are being pushed to their limits. Underground cable will be given more consideration (of being overloaded than overhead wire) since the costs to replace underground cable in melted duct work can be four times as expensive to replace. Overhead conductor will not be replaced until the overloads are reducing the life expectancy of the wire.

**Q. Does the grid itself add value to DG solar? If so, how should the value of the grid be considered when assessing the value and cost of DG solar?**

A. Yes, the grid provides value to DG solar. However, the inability to place a value on the service it provides – which is arguably immeasurable – is one of reasons a cost-of-service model is utilized for setting rates. This concept is one of the reasons the Companies take issue with not only net metering, but the idea of calculating a "value of solar" relative to the services the grid provides. It is expected that the utility provide safe, affordable, reliable, and increasingly cleaner electric service to all entities within its service territory based on actual cost-of-service, while we attempt to determine the "value of solar" above and beyond the cost-of-service benefits it offsets.

The grid itself, providing all of the required services necessary to support the customer's choice to install DG solar, is a critical component of DG solar. Utilities often mention that the grid provides all of the necessary ancillary services to compensate for DG solar's inability to self-provide (see earlier discussion), but what does that mean to the customer? What is the value to the customer of providing the necessary frequency and voltage support for the customers' electronics and appliances to operate properly? What is the value to the customer of providing the instantaneous back up generation necessary to prevent supply disruptions to the customer? What is the value to the customer of providing the necessary starting current to allow a customers' air conditioning system to run in the summer?

There are several reasons utilities and commissions around the country have established cost of service models for electric service, not the least of which is the inherent inability to place a value on such a necessary service. Any attempt to monetize the value of an essential service such as electricity, and the grid that provides that service, will ultimately produce "winners and losers". In its basic form as a support system for DG solar, the grid can be considered the "world's largest battery," providing all the same services as a customer-sited storage unit. Is the utility to be paid as a "storage facility" based on its value, or based on its cost of service? Since DG solar does not work without either the grid providing these services, or a self-contained storage facility allowing the customer to operate off-grid, wouldn't it be reasonable for the utility be paid the incremental savings a customer doesn't have to pay to go off-grid? Isn't that the equivalent value of the grid to the customer?

Inherently there is no fair mechanism for determining the value of the grid, as each customers' quality of life depends on its availability and reliability. The grid's benefit to

DG solar is undeniable, and should be both acknowledged and accounted for within a value of solar rate.

**Q. Does the deployment of DG solar result in a reduction in the use of water in electric generation? How should this be considered when determining DG solar value?**

A. Yes. Each MWh of production from renewable energy reduces the amount of water consumed through the production of electricity from conventional generation. This value could be accounted for in several ways. If the Commission were to adopt the wholesale rate for an equivalent value of solar, the cost of water would already be accounted for in the equivalent wholesale rate. Under the more complicated methodology that the Utah Commission has adopted and was previously described, this cost savings would show up in the cost of service models as a difference in the cost to serve. From a broader societal perspective, especially in arid climates such as Arizona, it can be argued that the value of water savings exceeds the cost of the avoided water usage. However, this value is again difficult to establish, and may be more appropriate to address through State and local tax policies affecting renewable energy resources.

**Q. Are there disaster recovery or backup benefits associated with the deployment of DG solar? Are they reliable and quantifiable enough to determine tangible benefits that might accrue to the grid?**

A. No. Unless the solar DG is part of an established micro grid, that is grid-connected and part of the established regional recovery plan, there is no value relative to disaster recovery or backup service.

**Q. What, if any, costs are associated with the utility providing voltage support and/or frequency support or other ancillary services in support of DG solar installations?**

A. DG solar installations are a growing percentage of generation supplying TEP's Balancing Authority ("BA") load but without the corresponding ancillary services. Ancillary services include Scheduling, Voltage Support, Regulation, Frequency Response, Imbalance, and Reserves. In the case of DG, Scheduling and Imbalance do not apply. Voltage Support, Regulation, Frequency Response, and Reserves by default are being supplied by the host BA.

Having an adequate supply of reserves is the key to being able to provide regulation and frequency response. Between BAs and Independent Power Producers the reserve quota is a function of generation. To date, this reserve responsibility has not been shared by the DG supplier.

Frequency response to disturbances is primarily provided by governor action on generators. Inverters on solar and battery storage systems can also provide frequency response but only if the inverter is not already at full output. In order for TEP to meet the new NERC frequency response standard (BAL-003), TEP carries spinning reserve that is distributed among its generating assets for governor action, and has contracted with battery storage service providers for inverter provided frequency response.

Voltage Support and VAR response between BAs is generally the responsibility of the host BA. Generating assets of another BA that reside within the host area are charged for the Voltage Support ancillary unless it can be self-provided. In the case of DG, this could work either way. Either TEP provides the reactive resources, or the DG inverters could be programmed for VAR response.

To date, DG solar has not been required to either pay for or self-provide these services. As a starting point for discussion on the appropriate charges for these services, the Companies would recommend using currently approved FERC tariff rates, at least for regulation, frequency response, and reserves which is required at the BA level. The customer could chose to self-provide VAR support, or pay the utility to provide.

**Q. Do you have any additional comments with regards to the questions posed by the Commissioners?**

A. Yes. The Companies appreciate the opportunity to address the Commissioners' questions regarding the most appropriate methods for evaluating and valuing DG. In addition to the testimony submitted here, Mr. Ed Overcast has filed comprehensive testimony that is more technical in nature and addresses other questions posed by the Commissioners.

**Q. Does this conclude your testimony?**

A. Yes.

# Exhibit CT - 1

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UNS Energy Corporation

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**Carmine Tilghman**
Senior Director, Wholesale, Fuels
and Renewable Resources

February 14, 2014

Arizona Corporation Commission
DOCKETED

FEB 14 2014

DOCKETED BY

Steven M. Olea
Director, Utilities Division
Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

RE: Inquiries re: Value and Cost of Distributed Generation
Docket No. E-00000J-14-0023

Dear Mr. Olea:

Tucson Electric Power Company ("TEP") and UNS Electric, Inc. ("UNSE") (jointly, the "Companies") hereby submit these joint comments in response to your Jan. 27, 2014 letter regarding the discussion of distributed generation ("DG") in Docket No. E-00000J-14-0023.

The Companies appreciate the Commission's interest in reviewing information regarding the costs and benefits of DG. Many public speakers and Interveners in Docket No. E-01345A-13-0248 offered broad, largely unsubstantiated claims about DG benefits as they argued against net metering changes proposed by Arizona Public Service Company ("APS"). The comments often failed to reflect ratemaking principles, the regulatory compact and the true costs that utilities incur to provide safe, reliable service to customers. This docket offers an opportunity to assess the quantifiable benefits that can be attributed to DG in a ratemaking context while also detailing DG costs and complications that can contribute to cost shifts and/or higher rates for utility customers.

**Relevance and Significance of Potential DG Costs and Benefits**

The relevance and significance of potential DG costs and benefits depends on the context in which they are considered. While rooftop photovoltaic ("PV") arrays and other DG systems create numerous impacts for their owners and the community at large, only some of these costs and benefits are relevant from a ratemaking perspective. Utility rates reflect only known and measurable service costs, not speculative future expenses, projected savings or broad societal impacts. To maintain consistency with ratemaking principles, the Commission should focus on DG costs and benefits that directly affect regulated utility rates and the cost of providing safe, reliable service. Just as utility rates do not reflect the comprehensive societal "value" of reliable grid power, they should not subsidize DG based on speculative economic and environmental benefits that have no direct, immediate effect on their utility's service costs.

The Commission also should consider DG's impact on the entirety of a utility's operations. Many of the most optimistic appraisals of DG's value focus exclusively on capacity, suggesting that a homeowner's installation of a rooftop PV system reduces a utility's potential long-term need to secure an equivalent amount of fossil fueled generating capacity. Such assertions ignore the immediate need for adequate operating reserves to account for the inevitable unavailability of intermittent DG resources and other necessary utility service costs, such as providing adequate voltage support on its local distribution grid to accommodate variable PV output. While the Companies are working to address the integration challenges associated with rising DG usage, the expense of these efforts must be considered in any comprehensive analysis of DG costs and benefits.

In this context, the Companies offer the following comments on the relevance and significance of the categories of DG values and costs listed in Mr. Olea's letter.

Capacity

- Distributed Energy Capacity Value (MW) – Assigning a proper capacity value to the variable output of renewable DG is relevant and significant to the Commission's consideration in this docket. The output of rooftop PV systems typically peaks at midday but fades significantly by the late afternoon, when the summer load served by Arizona utilities is at its highest. Accordingly, DG capacity is valued for long-term planning purposes based on the extent to which its output is coincident to the utility's summer peak loads. For net metering purposes, though, this value may be diminished because DG output is less coincident with system peaks in shoulder and winter months.

- Avoided Generation Capacity (New Generation $) – This is potentially relevant and significant over the long term, as DG output is reflected in utilities' long-term resource plans. However, the Commission also must consider additional generation capacity and future energy storage facilities that must be developed to balance the variable output of planned DG additions. For example, the Reference Case outlined in TEP's 2012 Integrated Resource Plan demonstrates the need for approximately 300 MW of natural gas turbines between 2018 and 2024 to provide backup capacity for intermittent renewable resources. In the near term, though, these potential costs and benefits are not relevant for ratemaking or net metering tariffs.

- PV System Orientation – This is relevant, as PV systems can be oriented to maximize their output during peak load periods. While this increases their capacity value, it reduces their overall energy production.

Grid Support Services

- Ancillary Services
  a) Reactive Supply and Voltage Control – DG systems cannot provide these services because they typically operate at full output, where reactive supply is unavailable. Also, while PV system inverters may be capable of reactive supply or voltage control, these features cannot be accessed by utilities' energy management systems. As such, this category is irrelevant.
  b) Frequency Regulation – Renewable DG systems cannot provide automatic frequency control on par with fossil fueled units and typically devote their full output to energy production, leaving no capacity to provide frequency regulation for the grid. As a consequence, utilities must devote a larger share of their own resources to this necessary service, reducing the efficiency of their generating units and increasing overall energy costs. These additional costs are both relevant and significant.

c) Energy Imbalance – Because DG resources are not scheduled, they do not contribute to imbalances between scheduled and actual grid resources. DG intermittency does create load balancing challenges and can contribute to gas supply imbalances when utilities must ramp up gas-fired resources to compensate for unexpected shortfalls in solar production. While such challenges might be addressed through participation in an Energy Imbalance Market, the cost of establishing and operating such a market in the southwest region may exceed its anticipated benefits for Arizona utilities. These additional costs would be both relevant and significant.

d) Operating Reserves – The addition of intermittent DG systems to the grid forces utilities to increase the energy reserves they maintain to regulate voltage and recover from disturbances. Utility reserves must be sufficient both in size and operational capability (including location and response time) to account for contingencies that include the loss or reduction of renewable energy output. These energy reserves represent a significant, relevant and growing cost of DG.

e) Scheduling/Forecasting – Because renewable DG resources are neither monitored nor controlled by the grid operator, their intermittent nature complicates utility load forecasts and creates unanticipated intra-hour generation swings. When DG output drops below forecasted levels, utilities must either secure resources on the real-time energy market or ramp up local generation operations. The additional cost of these resources relative to those that might have been secured in advance represents a significant and relevant DG cost. Conversely, DG production that significantly exceeds forecasted levels may cause additional wear and tear on utility generating units forced to ramp down output to accommodate the discrepancy.

- DG System Integration Costs – This category is relevant and significant because utilities incur substantial costs to integrate renewable DG systems into their distribution grids without compromising reliability. These costs are described more fully below in the section addressing distribution system investments. DG integration also creates administrative costs associated with feasibility studies, interconnection agreements and facility inspections.

Avoided Costs / Financial Risk

- Avoided Power Plant Capital Costs (Customer's Capital Contribution) – Although energy efficiency and economic factors have reduced the projected need for new power plants, any such savings directly attributable to DG usage would be relevant if they materialize in the future. So too would any *additional* power plant capital costs attributable to DG, such as increased quick start generation to address intermittency. For now, though, DG systems obviously do not help utilities avoid the capital costs of plants already in service. Indeed, DG users depend on existing power plants for reliable service, since their utility's potential system peaks must account for periods when their DG system isn't producing power. Meanwhile, any future savings in power plant costs attributable to DG must be offset by the increased capital cost of quick-response generating units needed to balance their intermittent output.

  Avoided Fuel/Purchased Power Costs – Such savings are relevant and could be significant, though they would be offset by additional energy costs associated with increased DG usage. While DG does reduce the use of energy from other sources, utilities must nonetheless ensure that generation assets are available to respond to customer load at all times. To the extent that this requires additional reliance on natural gas-fired turbines, utilities will incur higher gas pipeline costs and additional fuel expenses associated with these quick response units. These costs can be volatile, as evidenced by recent swings in the wholesale gas markets that boosted next-day prices at the El Paso-Permian hub from $4.50 to more than $24 per million British thermal units between Jan. 21 and Feb. 5, 2014.

- Avoided Fuel Hedging Costs – Such savings are unlikely to materialize because utilities will likely increase their reliance on natural gas to fuel the quick response turbines needed to balance intermittent DG output. That increased reliance would create higher hedging costs that could become relevant to calculations of DG costs and benefits.

- Avoided Line Losses – By reducing reliance on the output of remote, base-load generating plants, DG systems can reduce the amount of energy lost during long-distance transmission. The economic value of these reductions are relevant and could be significant, though it would be partly offset by increased distribution line losses associated with net metering and higher energy costs associated with greater reliance on natural gas-fired turbines.

- Avoided/Delayed Transmission System Investment – This is neither relevant nor significant. While increasing DG usage might reduce energy flows on existing transmission facilities, the historic investments in these facilities cannot now be avoided. Meanwhile, future transmission investments will not be meaningfully reduced by DG because utilities must account for peak usage during periods when renewable DG systems are offline.

- Avoided/Delayed Distribution System Investment – The growing use of DG will actually increase distribution system investments to a significant and relevant degree. Utilities will need to bolster their telemetry and frequency response tools to accommodate the intermittent output of grid-tied PV systems. In engineering terms, greater reliance on DG will reduce overall inertia on the distribution system, forcing utilities to compensate with increasing use of spinning reserves to avoid shedding load in response to frequency deviations. Meanwhile, the installation of larger DG systems often necessitates upgrades to local distribution and sub-transmission facilities to properly manage their output to the grid. The cost of such necessary investments in service reliability may ultimately eclipse any DG-related savings realized in other areas of utility operations.

- Avoided Renewable Energy Standard Costs – This category is not relevant, as any DG-related costs or savings utilities may realize in complying with the standard are anticipated by the rules themselves and are duly passed along to customers through the Renewable Energy Standard Tariff ("REST"). DG users should not receive additional compensation through rates paid primarily by other customers based on a claim that their renewable energy certificates ("RECs") can be secured more cheaply than those from other available resources. By that logic, utilities would be entitled to rates that reflect the most costly sources of power they might have purchased, rather than the resources they actually use. If the Commission were to eliminate the DG requirement, the owners of such systems would be free to market their RECs to utilities in open competition with other available renewable resources – thus realizing their true market value. Otherwise, it cannot be fairly said that DG resources provided under the terms mandated by the Renewable Energy Standard have "avoided" any costs.

- Avoided Utility Administration Costs –This category is relevant, but the Companies' experience suggests that DG has significantly *increased* utility administration costs. These costs include, but are not limited to, staff to work with DG customers and installers, increased information technology ("IT") infrastructure to manage regulatory reporting requirements, new reporting and administrative duties in metering and distribution services and additional training requirements to address safety risks posed by DG facilities.

- Avoided Market Price Mitigation (reduction of market clearing prices for natural gas and electricity) – The difficulty of proving any such effect likely renders this category irrelevant for ratemaking purposes. However, it would be reasonable to conclude based on the available evidence that DG actually increases market energy costs by boosting utilities' reliance on hourly power purchases and natural gas-fired turbine generators to compensate for intermittent PV output.

- Avoided Variable Operation and Maintenance ("O&M") Costs – While this category is relevant, DG actually increases utilities' variable O&M costs by introducing intermittency to a system better suited to stable power sources and more predictable load. Starting, spinning and stopping quick-response turbines and manipulating the output of larger plants to follow the variable load created by DG systems is expected to increase maintenance costs and shorten the useful lives of such units. This is particularly true for coal-fired plants, which are ill suited for following intermittent load. These impacts, combined with the cost of installing, maintaining and replacing the distribution system facilities needed to manage intermittency, would likely exceed the modest savings that might conceivably be realized through reduced midday load on distribution circuits serving DG users.

- Avoided Fixed O&M Costs – As with variable O&M costs, fixed O&M costs are not reduced by DG usage. Indeed, increased DG usage would likely increase fixed O&M costs for quick-response gas turbines on a dollars/unit of output basis, contributing to higher rates. Also, various distribution system components are subject to higher failure rates and/or shorter life cycles due to the voltage variations associated with increased DG penetration, leading to higher O&M costs.

- Avoided Power Plant Decommission Costs – At the point when it can be proven that DG usage has allowed a utility to avoid building a base-load power plant of a certain capacity, it might be possible to estimate the savings associated with not having to decommission a plant of that size at a theoretical location and designate that amount as a benefit of DG. Any such benefits would be offset, though, by the decommissioning costs associated with quick-response gas turbines and other facilities – such as energy storage devices – that will be required *because of* DG.

Security and Reliability

- Grid Security – This category is not relevant or significant, as DG systems do not meaningfully affect utility service costs associated with grid security. It may be suggested that DG enhances grid security by reducing reliance on energy delivered across long-distance transmission lines. But due to DG intermittency, utilities could not rely on such resources to serve load in the event a transmission line is offline due to a security incident.

- Grid/Service Reliability – As noted above, the variable nature of renewable DG output challenges utilities' ability to maintain stable voltage and adequate inertia for safe, reliable service. Accordingly, the quick response gas turbines and other improvements necessary to maintain reliability amid growing DG usage can be fairly described as costs created by DG.

Environmental

- Water Consumption – This category is relevant. TEP's generating portfolio consumes, on average, approximately 605 gallons of water per megawatt-hour ("MWh"). While increased reliance on natural gas and renewable resources will reduce this average consumption over time, rooftop PV systems provide immediate reductions in water use by offsetting energy production from fossil-fueled units. These savings will be reduced somewhat by the water usage of natural gas-fired generators used to back up and balance the intermittent output of DG systems. The economic value of net water savings attributable to DG is difficult to quantify, though it should reflect the actual cost savings at power plants with reduced water consumption.

- Cost of Environmental Compliance – To the extent that DG allows utilities to avoid developing new fossil fuel generation resources, it also could be credited for reducing some associated environmental compliance costs, including lime, emissions fees or monitoring expenses. Similarly, DG would create new permitting and compliance costs for the quick response gas turbines installed to balance their intermittent output. Finally, the potential exists for increased environmental regulation of PV panel construction and disposal methods. As with power plant construction and decommissioning expenses, it would be inappropriate for these speculative future environmental costs and benefits to be reflected in utility rates until such time as they can be proven.

- Health Effects (Benefits) – Enthusiasm for solar DG and other renewable resources reflects their positive environmental impact, including the public health benefits that can be realized by reducing our society's reliance on fossil fuels. But even if that health benefit could be quantified, there would be no place for it in customers' electric bills. Utility rates are designed to recover costs incurred in the provision of service and to provide utilities an opportunity to earn a fair return on the capital prudently invested for that purpose. In this context, DG costs and benefits that do not affect a utility's cost of service – however meritorious they may be – are not relevant.

- Non-Compliance Environmental Effects – Because utilities would not realize cost savings for reductions in non-compliance environmental effects, this category is not relevant for ratemaking purposes.

Social

- Economic Development and Jobs – Although DG installations have created jobs and widespread economic activity, utility rates are not designed to bill or credit customers for such broad societal externalities. Thus, this category is irrelevant in this docket.

- Civic Engagement/Conservation Awareness – DG systems literally bring home the benefits of "green" energy to utility customers, helping reinforce broader marketing messages about the societal benefits of renewable power. Children raised in the shadow of rooftop PV arrays can be expected to grow into adults who embrace the technology as a standard component of our energy infrastructure. That such beliefs do not impact utility service costs does not diminish their societal value. It does, however, suggest that they are not relevant for ratemaking purposes.

- Ratepayer/Consumer Interest – Consumer interest in renewable DG technology is driven in large part by the savings that can be realized through its use, partially due to incentives, tax advantages and cost shifts subsidized by other customers. Those savings are likely to increase over time, in part because higher utility rates will be required to recover the fixed costs that DG users avoid paying. In Docket No. E-01345A-13-0248, the Companies advocated higher charges for DG users to offset this cost-shifting impact for non-DG customers. While such a charge could affect consumer interest in DG, it would nonetheless serve the best interests of all ratepayers.

- Ratepayer Cross-Subsidization – As discussed more broadly in in Docket No. E-01345A-13-0248, the use of DG creates significant cross-subsidies that contribute to higher electric rates. Because electric utilities recover their largely fixed service costs through usage based rates, DG users enjoy subsidized grid service at the expense of customers without such systems. Arizona's net metering rules exacerbate this problem by overcompensating DG users for their systems' excess energy. Importantly, these cross-subsidies will persist *regardless of the economic costs and benefits that may be attributed to DG users.* In other words, the DG benefits discussed in this docket do nothing to mitigate the acknowledged cost-shifting that such systems are causing today under Arizona's existing net metering rules.

- Technology Synergies – If DG usage by a particular utility's customers can be proven to have created technology synergies that led directly to a reduction in that utility's service costs, such savings could be reflected in rates for DG users. Short of that, though, the assignment of benefits for theoretical synergies achieved through DG use is far too speculative for ratemaking purposes.

- Energy Subsidies – Taxpayers and utility customers subsidize DG systems through credits, incentives and rates established by elected officials. These subsidies have significantly boosted DG adoption rates, increasing the impact of any associated costs and benefits for utilities. To the extent that such subsidies are funded through utility rates, they increase energy costs and promote cross-subsidization, as noted above. While the merits and economic impact of these subsidies can be debated in their own right, such issues are not strictly relevant to the discussion in this docket – the determination of costs and benefits created by DG itself.

**Process and Methodology**

The costs and benefits discussed herein should be viewed from a ratemaking and service reliability perspective. Accordingly, the process and methodology for assigning monetary values to relevant DG costs and benefits should reflect the standards applied in utility rates. Those standards include:

- Relevance – Costs and benefits that fall outside the scope of utility ratemaking should be discarded. While DG systems may create broad societal benefits, such benefits are irrelevant for ratemaking purposes unless they measurably reduce utility service costs. Moreover, any identified benefits must be balanced by any costs necessary to ensure the DG does not interfere with safe, reliable service.

- Timeliness – Just as utilities are generally precluded from recovering costs not yet incurred or for plant not yet in service, the quantified value of DG generally should exclude estimates of future savings not yet realized. For example, a new rooftop PV system should not be credited for avoided power plant capital costs until it can be proven that the local utility has, in fact, avoided building a power plant. Such a method ensures that DG systems are not overvalued based on speculation about future benefits that may not materialize.

- Evidence – Any costs or benefits attributed to DG should be proven to the standards appropriate for utility ratemaking. For example, utilities' load balancing costs should not be attributed to DG systems unless research or other evidence can establish that such facilities are necessitated by intermittent DG output.

**Potential Presenters**

The Commission would benefit from presentations by experts familiar with the challenges of integrating renewable DG systems into utility grids and micro-grids. For example, Sean Hearne Ph.D, Manager of Energy Storage Technology & Systems of the Sandia National Laboratories, could provide helpful information regarding the complex integration of disparate generation types into a micro-grid and the challenges of modeling the different technologies. Additionally, a representative of the Western Electricity Coordinating Council ("WECC") should be sought out to address how DG systems affect utilities' ability to comply with grid reliability requirements mandated by the Federal Electric Regulatory Commission. Finally, the Commission should analyze the experiences of other jurisdictions as it continues to evaluate the value and cost of DG.

The Companies appreciate this opportunity to comment and look forward to further discussion of these issues in the proposed workshops.

Sincerely,

Carmine Tilghman

CC: Docket Control
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Commissioner Brenda Burns
Commissioner Bob Burns
Commissioner Gary Pierce
Commissioner Susan Bitter Smith
Parties of Record

**BEFORE THE ARIZONA CORPORATION COMMISSION**

**COMMISSIONERS**
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

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

Direct Testimony of

H. Edwin Overcast
on Behalf of

Tucson Electric Power Company and UNS Electric, Inc.

February 25, 2016

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## I. INTRODUCTION

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

**Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?**

A. I am a Director, Black & Veatch Management Consulting, LLC.

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.**

A. A detailed summary of my educational and professional experience is provided in Appendix A to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. My fields of study include microeconomic theory, industrial organization and public finance. I have been employed in the energy industry for more than 40 years in various rate, regulatory and planning positions. My industry employers include the Tennessee Valley Authority, Northeast Utilities (an electric and gas holding company) and AGL Resources (a gas holding company). I have been employed as a utility consultant since 1998 providing rate, regulatory, strategic and other consulting services to utility clients. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. I have previously testified before the Federal Energy Regulatory Commission ("FERC") on a number of electric, gas pipeline and oil pipeline issues.

**Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?**

A. I am testifying on behalf of Tucson Electric Power (TEP) and UNS Electric (UNSE or the Companies) collectively.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?**

A. Yes. I have testified on behalf of UNSE in their most recent rate case.

**Q. PLEASE PROVIDE A LIST OF STATE AND CANADIAN JURISDICTIONS IN WHICH YOU HAVE TESTIFIED.**

A. I have testified in Connecticut, Massachusetts, Georgia, Tennessee, Montana, Missouri, New York, Ohio, Michigan, Arkansas, New Jersey, Oklahoma, Kansas, Arizona and Maryland. In Canada I have testified before the Ontario Energy Board, the Alberta Energy and Utilities Board, the New Brunswick Energy and Utilities Board and the British Columbia Utilities Commission. My testimony has been related to issues such as cost of service, rate design, prudence, rate of return, regulatory risk, performance based regulation, competition and unbundling.

**Q. DURING YOUR CAREER HAVE YOU MADE PRESENTATIONS TO ENERGY RELATED TRAINING AND OTHER PROGRAMS?**

A. Yes. I have been an instructor for the Edison Electric Institute's Rate Fundamentals and Advanced Rate School related to cost of service. I have been an instructor in both the American Gas Association's Rate Fundamentals and Advanced Rate courses. I have been an instructor for the Southern Gas Association's Intermediate Rate Course and for the RMEL providing training related to regulation. I have made numerous presentations to trade association meetings including the EEI Rate Committee, the AGA Rate Committee, the AEIC Load Research Committee, SURFA and other industry sponsored programs. I have made presentations to NARUC events and events sponsored by academic institutions. I have also written broadly on various subjects related to utility regulation, including issues related to the integration of distributed generation into a utility system and the design of rates for the 21st century.

**Q. HAVE YOU PROVIDED EXPERT TESTIMONY ON COST OF SERVICE AND RATE DESIGN RELATED TO NET METERING, RATES FOR DISTRIBUTED GENERATION (DG) CUSTOMERS AND DEVELOPMENT OF RATES FOR PURCHASE OF ENERGY FROM DG CUSTOMERS?**

A. Yes. My testimony in Maryland addressed these issues and more related to cost of service, rate design, net metering impacts and the impact of purchasing excess generation at the full Standard Offer Service (SOS) rate. In that testimony, I developed specific measures of the level of subsidy created by net metering and demonstrated that the Commission's net metering rule resulted in undue discrimination based on the factual circumstances for the utility. I have also testified extensively in PURPA related proceedings on issue such as avoided cost and the purchase of energy and capacity from non-utility generators.

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The Companies have asked that I discuss determination of the cost shift from DG customers to non DG residential customers based on principles of cost causation and using cost of service analysis. I will also address the issue of net metering and how it serves to create unwarranted subsidies for DG customers including rates that are not just and reasonable. I will discuss the valuation of solar DG based on sound economic and regulatory principles. Finally, I will provide an evaluation of the role and value of the electric grid as it relates to rooftop solar, other forms of distributed generation, and customer-sited technology generally. By combining sound regulatory and economic principles I will address certain questions raised by the establishment of this docket and the balancing of interests required by a prudent and least cost approach to utility service under the new mixed monopoly and competition model that has become the reality for utility service. Where possible, I will identify analytical frameworks that can address the issues of this docket and provide a foundation for the most efficient and economic provision of safe, reliable and cost effective end-use services required by customers.

**Q. HOW IS YOUR TESTIMONY ORGANIZED?**

A. My testimony is organized by sections beginning with this introduction and followed by the following sections:

II. Some Initial Thoughts on the Mixed Competitive and Monopoly Model

III. Load Profiles for Solar DG Production and DG Customers System Usage

IV. The Cost of Service Approach

V. Allocation of Fixed Costs - Results of Three Studies

VI. Allocation of Energy Costs - Comparison of Residential Full and Partial Requirements Customers

VII. Solar DG Benefits - Near Term and Long Term Differ

VIII. The Outcome for Net Metering Must Meet the Objectives of PURPA

Each of these sections will be discussed below.

**Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.**

A. Using both cost of service for fixed costs and energy costs, I demonstrate the level of subsidy that results from both fixed costs and energy costs associated with net metering and banking. The level of subsidy is large and represents undue discrimination between residential solar DG customers and the other full requirements, residential customers. Table 1 below provides the subsidy that result from each component of the rate and the total subsidy per customer.

**Table 1**

**DG Solar Per Customer Subsidy by Component TEP**

| Source of Subsidy | Annual Amount per Customer (9645 Customers) |
|---|---|
| Non Power Supply Base Rate | $729 - $822* |
| Banking Arbitrage | $11.18 |
| Excess Generation | $73.42 |
| Premise Use | $60.13 |
| Total Per Customer Subsidy | $873.72 - $966.72 |
| Total Aggregate Subsidy | $8,431,948 - $9,328,933 |

* Based on the current cost of service and the cost of service for solar as a separate class of residential customers. This is consistent with utility ratemaking.

This is a large subsidy on a per customer basis. Individual subsidies will vary based on the size of the DG system. As such these subsidies are far larger than the subsidies that result from averaging costs over a class of customers. Based on this analysis, the current net metering with banking and the use of a less than compensatory customer charge and kWh billing makes it impossible to conclude that the resulting rates are just, reasonable, equitable and non-discriminatory.

I explain why solar DG customers need to be treated as a separate class for cost of service to properly reflect cost causation. I also show that there are no avoided distribution costs as the result of solar DG customers on the system. This conclusion is theoretically sound because the non-coincident peak demand on the distribution system occurs when solar DG customers are delivering excess generation to the system and there is no time diversity of solar DG production as there is with customer load. This is equivalent to stating that DG customers have their highest class NCP based on generation delivered to the system rather than net load on the system.

My testimony explains that economically efficient rates need to unbundled and each utility service priced separately so that customer make efficient decisions about the services they use. The unbundled rates include customer charges, demand charges and all energy related costs recovered outside base rates on a TOU basis that reflects the differences in marginal cost by season and by period for each day of the season.

I also show that efficient, market based capital avoided cost payments should be based on a proper calculation of avoided capacity costs and reset annually as the lower of the capacity market or the utility avoided cost. Solar DG customers should be compensated for avoided capacity based on the particular year when their production avoided costs occur over the useful life of the DG facility at a levelized annual rate determined each year.

## II. <u>SOME INITIAL THOUGHTS ON THE MIXED COMPETITIVE AND MONOPOLY MODEL</u>

**Q. PLEASE EXPLAIN THE CONCEPT OF A MIXED MONOPOLY AND COMPETITIVE INDUSTRY MODEL.**

A. This is not a new concept as other industries have been faced with similar issues. In some cases the very existence of the monopoly model has been replaced by competition entirely such as the case of the airlines and the trucking industry. In others regulators have developed tools to address the mixture of competition and regulation. Two examples that come to mind are railroads and liquids pipelines. There has also been an evolution of the mixed model in the electric industry. A major force behind the analyses of these events was Dr. Alfred Kahn who served as a Federal Regulator (the Civil Aeronautics Board), a State Regulator (Chairman of the New York Public Service Commission) and a regulatory scholar (The Economics of Regulation and any number of economic articles, papers and testimony).

Dr. Kahn described this model in a 1998 monograph published by The Institute of Public Utilities and Network Industries at Michigan State University. That Monograph entitled "Letting Go: Deregulating the Process of Deregulation" provides the description of the model as follows:

> It is clearly not possible to totally eliminate direct regulation of what we have traditionally considered to be the authentic public utilities. The reason, of course, has been the persistence of monopoly, particularly in the local distribution networks and also in electric transmission, which has required continuing regulation for two closely relate reasons:
>
> - To protect captive, principally residential and small business , customers;
> - To ensure fair and efficient competition between the integrated utility companies and the challengers dependent upon their access to their monopolized or partially-monopolized facilities, including safe guarding against cross-subsidization of that competition by the incumbent utilities at the expense of their monopoly customers.[1]

This is the fundamental concept of the mixed monopoly and competition model. Namely certain aspects of the public utility remain a natural monopoly, in particular the facilities

[1] "Letting Go: Deregulating the Process of Deregulation", Alfred E. Kahn, 1998, MSU Public Utility Papers, p. 17

associated with service delivery and more as will be discussed later. Several parts of this discussion apply to this proceeding. First, regulation is needed to protect the captive residential customers who cannot (or choose not to) avail themselves of DG or net metering, recognizing that this is at least a plurality and more than likely a majority of the residential class. Second, Dr. Kahn notes that competition should be fair and efficient. As I will explain later in this testimony the implications of net metering are such that the competition for the end use loads served by DG is neither fair nor efficient under the net metering, banking and volumetric rates commonly used for residential service. Third, and more importantly, I will show that net metering creates cross-subsidization, not by the incumbent utility, but by the rent seeking[2] behavior of the solar DG advocates that occurs at the expense of customers who remain monopoly customers.

Typically, the argument for this rent seeking behavior is that it will have a small dollar impact on customers providing the subsidy and the industry cannot make it on its own initially (the infant industry argument). Dr. Kahn specifically recognizes this behavior by these entrants and summarizes the impact of this behavior by noting "the encouragement that preferential subsidies and protections of this kind give to would-be competitors to devote their entrepreneurial energies primarily to seeking such preferences and ensuring their perpetuation by interventions before regulatory agencies and the courts, rather than concentrating on being more efficient suppliers than the incumbents."[3] With regard to solar DG the proliferation of roof top solar is not the least cost alternative to acquiring renewable energy resources or even solar DG as the cost of solar is subject to economies of scale just as the utility costs benefit from scale economies. This is demonstrated by

[2] Rent seeking is the activity of a person or firm that tries to obtain benefits for themselves through the political arena- the Arizona Corporation Commission in this case as well as legislatively through the PURPA amendment adding the net metering standard. Typically the benefit consists of a subsidy for their product or service including favorable tax treatment and measures that inhibit competitors such as inefficient regulated rates.

[3] Kahn, op. cit., page 21

the lower market price for solar when the price is market based compared to the implied price (with subsidies) associated with net metering. Particularly given that DG energy sales from roof top residential customers are worth far less to the utility under net metering than under a year round contract for solar generation. This is just another example of how markets have both a competitive option and regulation of the remaining natural monopoly.

**Q. WHAT ARE THE ESSENTIAL ELEMENTS FOR THE REGULATED DELIVERY COMPONENT TO AVOID CREATING CROSS-SUBSIDY FROM THE MONOPOLY COMPONENT OF THE MARKET TO SOLAR DG CUSTOMERS WHO HAVE CHOSEN COMPETITIVE ALTERNATIVES?**

A. One of the characteristics of true competition is that subsidies are not sustainable. Under regulation artificial subsidies may be sustained for a longer period of time but must be addressed ultimately if utility service is to be sustainable. Where the competitive market is subsidized through regulation, the result is that there is excess and inefficient investment in the favored competitive services such as solar DG in this case. The result will not be consistent with least cost planning or even efficient operation of the monopoly portion of the market. Ultimately, the monopoly segment of the market must establish fully unbundled rates so that when a customer uses a monopoly service the customer pays for the costs that that use imposes on the monopoly. To establish unbundled rates the cost of service must be unbundled for the services provided. Rates must be developed that signal the factors that cause cost by customer groups that have homogeneous characteristics that cause the cost. When rates reflect class cost of service on an unbundled basis and the underlying cost of service reflects the principles of cost causation and matching, subsidies will be eliminated; the price signal in the rates will incent efficient use of resources; rates will be just and reasonable; rates will not be unduly discriminatory; investment in DG will be consistent with least cost planning and efficient competitors will earn the required market return for the risk associated they take. In summary the following elements must exist for long term stability and sustainability of the mixed market model:

1. Cost of service reflects cost causation for each class of customer.
2. Rates match cost in the rate effective period.[4]
3. Rates are fully unbundled such that all energy related costs are recovered in energy charges (preferably seasonal and time differentiated based on marginal cost differences), fixed capacity costs are recovered in demand charges and customer costs in customer charges that may not be the same for all customers in a class when the services they select differ.
4. Price signals should reflect marginal cost to the extent practical while still matching costs and revenues.
5. Costs not included in test year revenue requirements such as the present value of future avoided costs or the levelized cost of future avoided energy should not be part of rates or part of valuation of assets that have no long-term, enforceable, contractual obligation for service and even with a long-term power purchase contract energy should be valued at the market as the market changes through time.

[4] The rate effective period is the first year after new rates take effect. This is simply a statement of the court mandated requirement that rates provide the utility a reasonable opportunity to earn the allowed return not only in total but that the rates match the cost of service by class of customers.

**Q. IN ESTABLISHING CLASSES OF SERVICE IN THE MIXED MONOPOLY AND COMPETITIVE MARKET, WHAT ARE THE ESSENTIAL ELEMENTS SUPPORTING RATE CLASS DETERMINATION?**

A. It is essential that rate classes be established based on factors that cause known differences in cost of service. These factors include voltage level of service- secondary, primary, sub- transmission and transmission or some subset of these factors based on the types of service the utility provides. Voltage level is important because it impacts energy costs (delivery losses) and capacity costs (extra equipment not used by other classes of service and the required level of capacity). Quality of service (firm or non-firm) is another dimension for determining the classes of service. Type of service is another dimension such as full requirements or partial requirements that result in different demand characteristics for different portions of the system. Special service arrangements may impact the definition of classes. This would include customers who require redundant facilities for reliability or unusual load characteristics such as very low load factors. Finally there may still be a need to recognize differences by traditional end use classes such as residential, commercial, industrial or size of customers within a class. The need to create multiple rate classes based on cost causation will be reduced. So the number of rate schedules in a tariff should be more manageable.

**Q. YOU NOTED A DIFFERENCE BETWEEN FULL AND PARTIAL REQUIREMENTS CUSTOMERS. PLEASE EXPLAIN THAT CONCEPT.**

A. Full requirements customers are those who purchase the full bundle of services provided by the utility. Partial requirements customers are those who choose to select only some of the services provided by the regulated utility. To the extent that the selection of the services provided by the utility results in a different mix of hourly loads and more or less use of particular services provided by the unbundled utility, the partial requirements customers must be treated separately for cost recovery for rates to be just and reasonable. There are many different categories of partial requirements customers. For example, customers who buy competitive generation services while using the utility for delivery of those services are no different with respect to delivery services than full requirements customers who use delivery services for utility generated services. By unbundling delivery service from generation services customers in the same class may make competitive choices and pay rates that are just and reasonable for delivery regardless of the source of energy and capacity for generation.

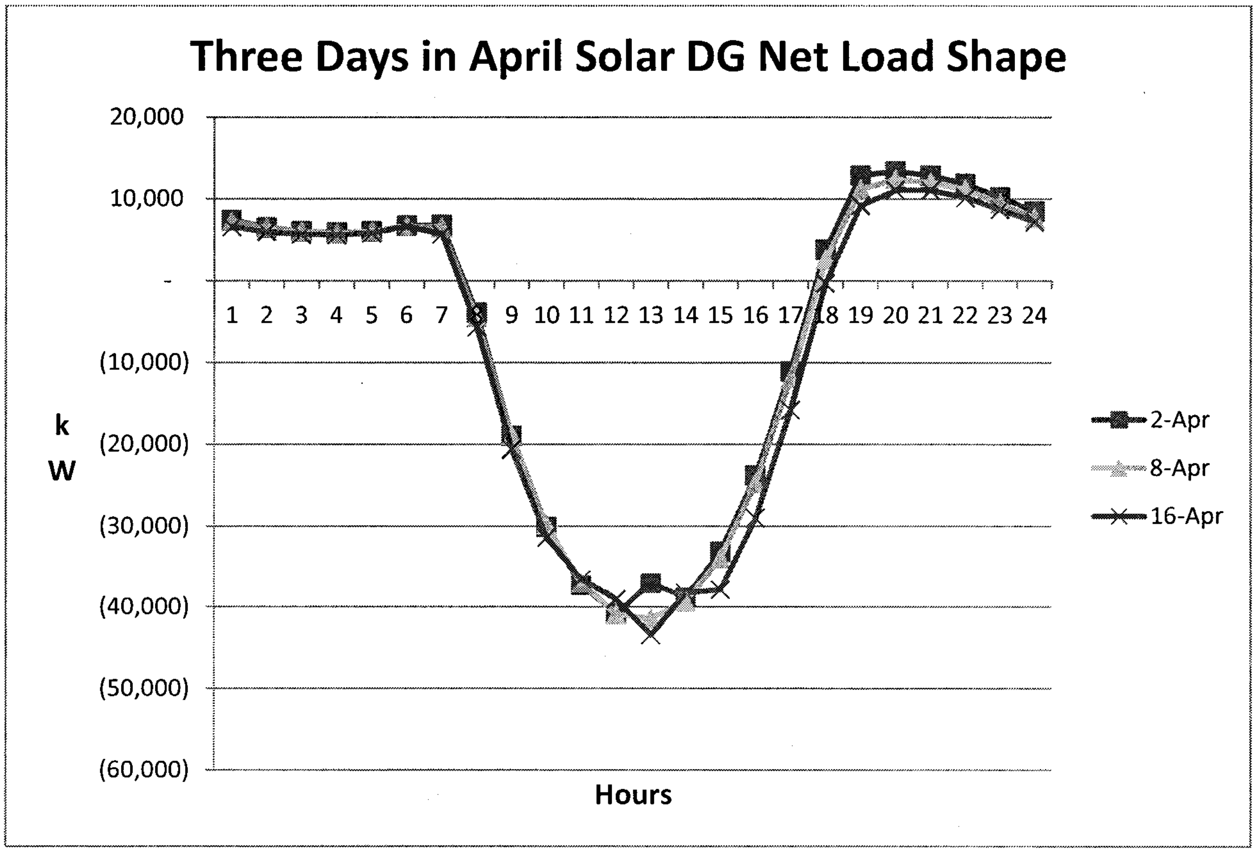
For other partial requirements customers the competitive services they purchase may change the cost characteristics for the customers. A simple example will illustrate this concept. Suppose a customer owns a run of the river hydroelectric generator that is used for supplying a portion of the customer's energy and capacity. By its nature a run of the river facility has highly variable output based on weather. During rainy periods the output is higher than dry periods when output may even be zero. For a summer peaking utility that may mean that there is no capacity at the generation peak of the utility and thus no capacity savings from the facility but only energy savings. It is likely that the facility produces its maximum output in the spring and fall so that the energy value is even less than the average energy value. As for delivery charges-transmission and distribution the customer looks just like any other summer peaking customer for those charges as well. The potential for cross subsidy from other customers is high if costs are recovered in a simple two-part rate using average kWh charges. The subsidy is minimized if demand costs are recovered in demand charges, customer costs in customer charges and energy costs are based on seasonal time of use kWh charges.

**Q. WHY WOULD A UTILITY NEED A SEPARATE RATE CLASS FOR PARTIAL REQUIREMENTS CUSTOMERS?**

A. A separate class for partial requirements customers is needed when the customers use the system differently than other customers who have the same end-use loads. Different usage patterns result from how a partial requirements customer uses the system. Solar DG customers provide an excellent example of a group of residential customers that use the system very differently from full requirements customers. These customers use the system for much more than the delivery of kWhs they consume when solar DG is not available or inadequate to serve the total hourly load. Some differences include the use of the system for the sale of excess kWhs back to the system. Under net metering with a banking provision solar DG customers use the system for virtual storage just as if they had a very large battery that would allow them to put kWhs in the battery in low load periods and draw them out of storage to offset purchases in high cost periods. This is a service that is free under net metering but is not free from subsidy from other customers who pay for the storage service and the price differential between high load, high cost periods and low load, low cost periods. Other customers also pay for the losses associated with the delivery to storage and the delivery back to the customer under net metering where there is no loss adjustment associated with the transaction. The solar DG customers also use the distribution system differently. The reason that the distribution system is used differently is that while there is natural diversity in customer loads that produce the class load NCP, there is no natural diversity at the class NCP for solar DG sales of excess generation. The maximum output of all of the solar DG customers occurs at the same time because the DG facilities are all or predominately designed to maximize kWh production and are fixed axis solar DG installations. The peak production occurs on the coolest day in the spring and at mid-day. There is no diversity in the sense that some customers peak later or on a different day because of the inherent technological and operating characteristics of solar DG. In a sense this peak is like the gas system peak that occurs for all heating customers on the same day based on the weather conditions. This means that it is possible that the class NCP for solar DG actually occurs on a day not based on load but based on delivery of power back to the grid. That is the case for TEP where the delivery NCP is greater than the load NCP. The solar class NCP occurs at noon in March or April when almost twice as much power is delivered to the system than the solar class contribution to the load NCP on the hottest day in the summer. Figure 1 below illustrates the nature of the generation delivery to the utility system for three days in April where the highest delivery is 43,429 kW at 13:00 hours using the hour ended concept used by utility dispatch.

**Figure 1**

**April Solar DG Net Load Shape**



The distribution system must be able to accommodate bi-directional delivery service and serve the load at which ever maximum occurs- either load NCP or generation NCP. This high load also raises marginal losses on the local facilities that impact the net delivered power from solar DG for the grid.

To properly allocate delivery service costs to DG customers it is necessary to recognize the actual class NCP. It also means that for customers who respond to the energy price signal and size their system to minimize the utility bill there are no possible distribution cost savings. This also means that when kWs are sent back to the system in these low load periods the system power factor deteriorates because solar generation produces no vars. In order to resolve the lower power factor associated with solar DG it is inevitable that distribution costs will increase as the utility installs switched capacitors to manage the system power factor. The alternative to the low power factor is to require smart inverters as part of the interconnection standard. This is similar to the provisions in rates for larger customers that either bill customers on a kVa basis or include a power factor adjustment provision that recognizes lower power factor has a cost as in the large customer rates for TEP.

There are other uses that solar customers make of the system such as synchronization of solar generation with the grid, in rush current, supplemental service and backup service. These services all result in differences between the residential solar DG customers and full requirements customers. For example when a full requirements customer uses in rush current to start a motor load there is also kWh use that is billed. For a solar DG customer there is no kWh use when the solar DG is operating and meeting the load but the in rush current is used. The pattern of supplemental service is such that solar DG customers require utility service in some of the highest cost hours based on the limited energy from solar DG in those hours. These are all unbundled services used by solar DG some of which they do not compensate the utility for the costs they cause and others which they pay less than the full costs under the two-part rate.

## III. LOAD PROFILES FOR SOLAR DG PRODUCTION AND DG CUSTOMERS SYSTEM USAGE

**Q. IS IT POSSIBLE TO ILLUSTRATE THE PROFILE OF SOLAR DG OUTPUT AS IT COMPARES TO HOURLY MARGINAL COSTS?**

A. Yes. Exhibit HEO-1 provides a comparison of solar DG production from a fixed axis south facing facility and the hourly load profile of the TEP system. It shows that the solar peak output is either declining or zero at the time of the monthly system peak loads. Exhibit HEO- 2 provides a comparison of solar production from a fixed axis south facing facility to the hourly marginal costs for TEP system. As that data shows in many high cost hours the solar DG production is declining or zero and that peak production hours uniformly do not match peak marginal cost hours in either the summer or the winter. The mismatch is even greater during the peak day because of the impact of ambient temperature on solar DG output. As the temperature of the facility rises above 25 degrees Centigrade (C) (77 degrees F) , solar output declines at a rate of about four tenths to one half of a percent per degree C. If the solar panel is cooled passively by ambient air flow the output loss for the average peak day temperature in Tucson would be about 9% of rated kW capacity. If the panels are not cooled (mounted on the roof directly) the panel temperatures could reach 60 degrees C and reduce output by 17.5% of the standard rating. Conversely, when temperatures are below 25 degrees C the output of the solar DG exceeds the rated capacity by about the same one half percent per degree C. As a practical matter this means that the maximum solar output occurs in March and April low load periods that are between one half and two thirds of the class NCP peak load for typical full requirements residential customers.

**Q. WHAT ARE THE SYSTEM IMPLICATIONS FOR MAXIMUM OUTPUT DURING LOW LOAD PERIODS?**

A. When the hourly output maximum occurs in low load periods more of the output flows on to the system and places more demand on the distribution facilities required to provide delivery service of excess energy as shown above in Figure 1. In simplest terms the diversified demand of residential DG customers delivering power back to the grid at the midday hours, weekdays in March and April is larger than both the customer NCP load demand and the residential class NCP demand. Using data prepared by TEP based on hourly load data for about 374 full requirements customers with annual kWh usage above 13,000 kWhs and overlaying their usage with solar loads modeled using the National Renewable Energy Laboratory (NREL) solar data base for Arizona for 24 months from mid-2013 to mid-2015 we reach the same conclusion as found above with respect to the total class of Solar DG customers. This further confirms that the distribution system must be designed to meet this higher solar class NCP load rather than the residential class customer NCP load used for full requirements customers. The maximum average customer NCP (the sum of the highest hourly loads for all customers in the data base) for full requirements customers occurs in July at 12.87 kW per customer. The maximum excess delivery by a partial requirements customer occurred in April at 13.79 kW per customer. Although the differences are small, about one kW, the data confirms that there would be no distribution cost savings associated with the equipment in accounts 364-368. The logic behind the high level of excess delivery in that time period is quite simple when one considers that the average kW load for residential customers in the noon hour in March and April is 0.75 kW per customer. For even a small 5 kW solar DG facility the extra output above the nameplate wattage would result in about 4.5 kW flowing back to the system. Taken with other load data on class NCP it is also reasonable to assume that there would be no savings at the substation level for peak loads of solar DG customers.

It also points out that there will be losses associated with the excess energy before it is delivered to other customers meaning that the virtual storage of excess generation is reduced by losses when the kWhs are delivered to the system and additional losses when the kWhs are returned. In simple terms the banking provision creates a subsidy from not only the timing of the kWhs but from the smaller amount of kWhs actually banked and delivered. I asked the Company engineers to estimate the losses associated with this excess energy flowing back onto the system. Exhibit HEO-3 shows the losses on a one line diagram for delivery to other customers and the system prepared by the Company. There are several important points to recognize in this analysis. First there are real losses even for one solar customer on a typical installation. Second, even with only a single solar customer load flows back on to the delivery system in these low load high production periods. That is, all of the output is not consumed by the other customers on the same transformer and even if it all was consumed there are still real losses. Third, this analysis is conservative because it does not assume any impact associated with delivery of Vars. These losses are only part of what should be counted as losses associated with the solar service because that service is not available without the system no load or core losses as well.

Another implication relates to the increased losses for the var requirements that must be produced by the utility system to deliver the pure kW sent to the utility system. Although it is not possible to quantify these extra costs in detail it is important to understand that these services are not free and that other customers provide additional subsidy to solar DG customers that are not included in either the cost study for fixed costs or in the marginal energy cost analysis. Rather, it is reasonable to conclude that the subsidy from full requirements customers is conservative estimate.

**Q. PLEASE EXPLAIN WHY YOU HAVE USED TWO DIFFERENT DATA SETS FOR SOLAR LOAD PROFILES IN YOUR ANALYSIS.**

A. Both data sets have value for analysis depending on the purpose of the analysis. In this case, the actual data from Rio Rico provides a better representation of actual hourly loads because it is able to reflect both temperature impacts and local weather variations. The NREL data is used as a second source of solar output to confirm the results from the full analysis based on Company data alone.

**Q. PLEASE DISCUSS THE ROLE OF LOSSES IN CALCULATING DG BENEFITS AND COSTS.**

A. Solar advocates argue that because DG is behind the meter that avoided losses should be reflected in both cost analysis and in computing the benefits of DG. Most of the discussion around losses makes statements such as the avoided losses are higher than average losses. These statements ignore the economics of losses because the no load losses are not changed as part of the calculation of marginal losses and the low power factor for DG customers results in higher losses that the average when power is consumed. For example, if the power factor for a customer was 50% the current required to serve the load would double. As current doubles the losses increase by I^2 or 4 times the losses of pure power.

**Q. HOW DOES THIS LOAD INFORMATION IMPACT COST OF SERVICE?**

A. While I will explain the impact on the cost study in more detail below, this data means that the allocation of distribution costs for solar DG customers who have little or no diversity in their production loads on the distribution system cause higher total delivery costs than would be reflected by including those customers as residential customers in the costs study. Using the residential load data will result in too little cost allocated to the partial requirements DG customers because these customers are larger than the average customer. To develop a cost study based on cost causation the partial requirements DG customers should be treated as a separate class and allocated costs based on their own class NCP for distribution. The different load demands on the system from the two classes as well as the energy price arbitrage that occurs under net metering with banking requires treatment of solar customers in their own class.

**Q. DO THE DIFFERENT COST CHARACTERISTICS IMPACT RATES FOR PARTIAL REQUIREMENTS CUSTOMERS?**

A. Yes. Portions of the unbundled rates for partial requirements customers will be different from full requirements customers. There will be no difference in the seasonal TOU energy rates since the service to both groups will be based on service at the secondary level. The demand and customer related costs will be different and those portions of the rate should reflect the differences in per unit costs. In part, this is because the partial requirements customers are lower load factor customers from the system delivery perspective. It is also true that these customers use a different set of services than full requirements customers and hence cause different costs to be incurred.

## IV. THE COST OF SERVICE APPROACH

**Q. PLEASE DESCRIBE THE COST OF SERVICE STUDIES DEVELOPED IN THIS CASE.**

A. There is no practical way to assess the costs caused or the revenue requirements for full and partial requirements customers without developing a cost of service study that identifies these two classes of residential customers in separate classes for fixed costs and in separate studies for variable energy related costs. I have prepared three different cost studies to allocate the fixed costs of TEP based on the cost study filed in the current TEP rate case. I say fixed costs because the three studies produce results that only allocate costs that are classified as customer or demand costs and do not include any costs classified as energy. I will refer to these three studies collectively as the fixed cost studies. The energy cost studies use hourly costs for full and partial requirement customers to assess the energy related costs and include an analysis of marginal energy costs for each category of residential customers.

**Q. PLEASE DESCRIBE THE THREE FIXED COST STUDIES.**

A. Based on a decision by the Public Service Commission of Utah in Docket No. 14-035-114 issued November 10, 2015, the Utah PSC adopted a methodology of comparing two cost studies to determine the costs of serving solar customers for ratemaking purposes. The first cost study is the standard cost study with the solar NEM customers' allocated costs just like the residential class based on actual load characteristics of the class. The second study that Utah refers to as counterfactual cost study (CFCOS) assumes that the solar customers did not adopt DG but rather were full requirements customers allocated costs in the same way as the residential class. This study is essentially an embedded cost study that assumes all other things being equal except for the addition of solar PV at the customer premise. By comparing these two studies it is possible to identify the way costs change for both full and partial requirements customers assuming that the load characteristics in terms of both load and delivery capacity requirements are no different. All other things are not equal when viewed from the factors that cause costs. Since we know that the load characteristics are not the same, I recommend a separate class for evaluating the embedded costs of solar DG customers rather than using the counterfactual study alone with its inherently biased assumption about cost causation. That is the third fixed cost study I have included.

For each cost study we use the same fixed costs for the system based on the 2015 rate case costs as filed in the TEP cost study. Those fixed costs are allocated using the same basic methodology of average and excess for production costs and the minimum system customer costs and class NCP for demand related delivery costs. We also use the same customer cost allocations. Using the same customer cost allocations is a conservative approach because TEP has made no effort to account for the higher level of transaction costs for solar DG customers associated with storage accounting, billing adjustments and other customer service considerations. The study is also conservative because we have made no attempt to identify any system investments designed to address power factor issues or other distribution related investments. There is also no adjustment for higher losses associated with the power factor issue noted above.

**Q. PLEASE DESCRIBE THE TWO ENERGY COST STUDIES.**

A. As noted above the load shapes of full and partial requirements customers are significantly different in terms of how the system must respond to the load shape of solar DG customers as compared to the full requirements customers. In addition to the load shape differences, solar DG alters system dispatch because of the nature of the net load shape for these customers. The net load shape for solar DG customers in the spring months of March and April and the fall months of October and November is illustrated in Exhibit HEO-4. The significance of these months for system operation is that these are the months when utilities typically schedule baseload and other units for maintenance. In considering the total demand on capacity (the sum of load demand, scheduled outage demand, forced outage demand and unit deratings) these months may have higher total demand on capacity than other months although typically not the peak months. This implies less flexibility to meet load when loads increase rapidly as it does on almost every day in this period. This results in higher marginal costs because the loads must be met by fast start units that are typically combustion turbines. It also means that ramp rates become an important consideration for maintaining spinning reserves and operating reserves. The two energy studies compare the dispatch of the system with the assumption that the total load was from full requirements and partial requirements customers and the actual dispatch reflects the variability of solar DG in the loads. This is another example of the conservative nature of the analysis when compared to separate dispatches of the two groups.

**Q. PLEASE EXPLAIN THE DIFFERENCES IN THE TWO ENERGY STUDIES.**

A. The first study is the hourly energy costs based on the expected load in the test year including the solar DG load. The second study uses the counter factual load shape and excludes the sale of excess energy back to the system since under the counter factual analysis there is no excess generation. We have used the hourly energy cost analysis to also compare the marginal and average energy costs associated with the full requirements residential customers and the partial requirements DG customers. We have essentially used a production costing model to compare energy costs with and without solar DG. All of these results will be discussed below.

**Q. DO THE COST STUDIES COMPLY WITH THE PRINCIPLE OF COST CAUSATION?**

A. Yes. The studies follow the standard process of functionalization, classification and allocation for each unbundled component of costs. Costs are functionalized as generation, transmission distribution and customers.

The production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the grid and to move power from generation to load. In this case, this is allocation of the expense transmission by others.

The distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. In recognition of this fact, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are allocated between distribution and customer service accordingly.

The customer service function includes plant and expenses caused by individual customers. Customer service includes meters, service lines, meter reading and billing, for example. It also includes a portion of the distribution system including transformers, conductor and poles.

**Q. WHAT IS CLASSIFICATION?**

A. Once costs are functionalized, they must be classified based on the categories customer, demand and energy. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built and operated. This is a particularly important concern when developing costs for customers who use the system differently and who create new costs to accommodate the customers' system impacts.

**Q. WHAT ARE DEMAND COSTS?**

A. Demand costs are those costs that vary with some measure of maximum demand. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

**Q. WHAT ARE ENERGY COSTS?**

A. Energy costs are those costs that vary directly with the production of energy such as fuel costs, other fuel related expenses or purchased power expense.

**Q. WHAT ARE CUSTOMER COSTS?**

A. Customer costs are those costs that vary with number of customers such as meters and service lines.

**Q. CAN COSTS BE CLASSIFIED INTO MORE THAN ONE CATEGORY?**

A. Yes. For example, some distribution costs may have both a demand and a customer cost component.

**Q. WHAT IS THE ALLOCATION PROCESS?**

A. In this step, costs are allocated to customer classes based on a variety of factors. The purpose of allocation is to assign costs to classes in a manner that reflects the factors that cause the costs to be incurred.

**Q. PLEASE EXPLAIN HOW YOU DEVELOPED ALLOCATION FACTORS FOR THE STUDY.**

A. To develop the allocation factors for the cost study it was necessary to make a basic assumption that the load shape of residential solar DG customers was on average the same load shape as the residential load shape prior to the installation of solar DG. That is the basic assumption is that the hourly usage pattern for DG customers is no different from the residential class as a whole. The only difference is that solar DG customers provide some of their own energy to satisfy that load shape based on the operation of solar DG.

Using this assumption it is possible to develop a full requirements load shape for solar DG customers using the following data: actual metered kWhs used by solar customers per month, actual excess kWhs delivered to the utility by month, the installed kW capacity of the solar DG, the solar output load shape based on metered data for a fixed axis, south facing solar DG installation, and the load research based residential hourly load shape. With this data the process consisted of a number of logical steps as follows:

1. Using basic number properties of mathematics we calculated the monthly full requirements load for each solar DG customer as the sum of the actual metered kWh plus the monthly solar generation given by the installed capacity times the hourly output load profile less the metered excess energy delivered back to the system. From this calculation we saved both the premise load and the excess energy for use in the various analyses. The value of this calculation cannot produce negative kWh. As a result, we eliminated about 200 observations from the data set because the excess kWh sold back to the utility were not possible. For example in one case the kWhs delivered to the utility in a month exceeded

83,000 for a DG facility with 8.42 kW of capacity; a result that is physically impossible. This is an example of an obvious data error.

2. Using monthly total energy consumption of the premise and the residential hourly load shape based on the customer's monthly premise use, an hourly load shape of premise use is calculated for each month by taking the ratio of the customer's monthly use to the monthly use of the load shape. In this step we modeled the average solar DG customer as a full requirements customer with the system average load shape.
3. This process was repeated for each residential DG customer and the data aggregated into the DG customers' counter factual load shape for use in the counterfactual cost study.
4. The solar DG class is based on all customers with twelve months of data and a non-zero capacity value. (The Company data set did not have a kW capacity for all of the solar customers and those were excluded from the analysis.)
5. For the counterfactual study the full requirements customer load shape is calculated by subtracting the net load shape of solar DG from the residential load shape used in the base cost study and adding back the full requirements load shape.
6. The solar net load shape is the premise hourly load shape minus the generation output shape. The net load shape excluding excess generation is used to develop the solar contribution to the residential load shape for the base fixed cost study.
7. We now have three load profiles for solar DG customers: the counterfactual no solar DG load profile, the generation output profile and the solar customer net load profile.
8. Using this data it is possible to calculate the solar customers demand allocation factors for each fixed cost study and for the energy cost studies.

9. For the counterfactual profile we calculate the residential class Average and Excess Demand (AED) and NCP allocation factors and rerun the cost of service study. We also use the net load profile and calculate the AED and NCP allocation factors using only the net positive energy for AED and the higher of the positive or negative class maximum NCP. The allocation factor for NCP is the absolute value of the class NCP. This is consistent with the maximum requirement for distribution facilities and cost causation.

This data provides a solid, if conservative, basis for assessing for assessing the relative revenue requirements differences between the between full and partial requirements customers.

**Q. HOW DOES ONE DETERMINE THE FACTORS THAT CAUSE COSTS?**

A. In many cases determining cost causation is as simple as asking the question of whether a particular cost changes when some potential allocation factor changes. If a factor causes costs, costs will vary with changes in that factor. For example, if the number of kWhs increases, does the cost of some input such as miles of conductor increase? Since the miles of conductor do not change with kWhs either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that miles of conductor increases for customers added to the periphery of the system, thus customers are a cause of the cost. We also know that the miles of conductor increases with the growth of the peak load on the conductor and that load may be met by paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three-phase conductor. This means that some of the cost of conductors is also caused by the demand on the conductor. In any case, the factors driving the cost of conductors are customers and a measure of non-coincident peak demand. Following this logical process allows one to determine cost causation for each element of the system.

**Q. WHY ARE THE PROCESS OF COST OF SERVICE AND THE PRINCIPLE OF COST CAUSATION SO IMPORTANT IN ASSESSING NET METERING POLICY AND RESULTS?**

A. It is important to recognize that there are many different views on cost of service. Different views are driven by the zero sum nature of the cost study. When customers can develop positions on allocation that benefit their constituents there is an opportunity to have more favorable rates. This is consistent with the underlying concept of rent-seeking without having to specifically request a direct subsidy although some advocates engage in both types of behavior. For example, solar advocates often recommend cost allocation methodologies that minimize the customer component in order to maximize the kWh charge in the two-part rate. It is not uncommon for these advocates to recommend use of the basic customer method to allocate customer costs because this method produces the lowest possible customer charge other than recommending zero.

**Q. PLEASE COMMENT ON THE BASIC CUSTOMER METHOD.**

A. The basic customer method is not a method for calculating the customer component of costs that is based on the gold standard of cost causation because it fails to reflect any costs more than meter, service and direct customer accounting costs such as meter reading and billing in the customer costs. It is simply a result driven methodology (lower costs for the residential class and for smaller customers in the class and higher per kWh charges under the current two part rate design) that does not meet the criteria of theoretically sound cost causation. As a result, all of the remaining distribution system costs must be classified as demand and allocated on some measure of NCP. This includes USOA accounts 364-368. By failing to classify accounts 364-368 as both customer and demand, the resulting cost analysis suffers from significant defects related to cost causation.

First, residential customers are allocated a disproportionate share of scale economies in the distribution system. Residential transformers in account 368 have substantially higher costs per kVa of installed capacity than larger demand customers, typically more than twice the cost per kVa. Demand allocation alone assumes the same cost per kVa for all classes.

Second, the use of demand to allocate costs for investments in accounts 364 through 367 over allocates the quantity of these inputs to larger customers who have higher NCP demands and assumes that miles of conductor is proportional to demand and not to number of customers. This is empirically an incorrect assumption.

Third, public utility regulatory accounting including the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") supports the classification of distribution plant between customer and demand. Based on these factors the Basic Customer Method is never a viable alternative for calculating the facilities charge. Thus TEP in its study and in the alternative fixed cost studies use the minimum system that recognizes the customer portion of delivery costs.

**Q. HOW DOES THE AED METHOD FOR ALLOCATING GENERATION CAPACITY IMPACT SOLAR CUSTOMERS?**

A. The AED/4CP method used by TEP in the cost study recognizes that low cost energy results from higher capacity costs. Since solar DG customers use lower cost energy from the utility at night they should also pay for a portion of the fixed capacity costs of baseload units in order to buy the low marginal cost energy. While the AED concept was developed for cost allocation for full requirements customers it results in a more appropriate allocation than would a CP methodology that allocates all capacity costs on a daylight peak hours. Whether the allocation is ultimately reasonable without modification is a fair question for review in rate case proceedings.

**Q. HAVE YOU USED THE SAME DATA AND INTERNAL ALLOCATION FACTORS AS TEP?**

A. Generally, the cost studies use the same data for revenue requirements and for allocation factors with the exception of creating a separate column for solar DG customers. We have also changed the use of the minimum system to classify costs. In the base study the solar customers' data and the full requirements customers sum to the same residential allocation factors in the TEP filed study. We have not calculated the revenues for each class and those have been excluded from the study so that the only information presented is the total cost based revenue requirements. For the other two studies the total revenue requirements remain the same and only the allocation factors for the solar DG customers have changed. In the counter factual study the customers are allocated the revenue requirement that would result from these customers being full requirements customers. This measures the cost shift between full requirements and partial requirements customers. This recognizes the practical reality of the zero sum nature of the cost study. Increasing the demands of solar DG customers result in lower costs allocated to all the other residential customers.

**Q. PLEASE EXPLAIN THE CHANGE FOR THE CLASSIFICATION OF CUSTOMER COSTS USING THE MINIMUM SYSTEM.**

A. In the TEP cost study TEP applied the classification for the minimum system to the costs after using the class NCP to allocate the distribution plant accounts. The use of NCP to allocate distribution plant accounts 364-368 under-allocates distribution plant to residential customers and understates the customer cost component of unbundled rates. After making that methodological change the allocation differs from TEP even though the total revenue requirements remain the same. The result of this change is to allocate more costs to the residential class to reflect the impact of customers on the distribution system costs. It also impacts the unit customer cost component. This adjustment is consistent with the use of the minimum system method as discussed in the NARUC Electric Utility Cost Allocation Manual and the three step cost of service process of functionalization, classification and allocation.

## V. ALLOCATION OF FIXED COSTS - RESULTS OF THREE STUDIES

**Q. PLEASE SUMMARIZE THE RESULTS OF THE THREE FIXED COST STUDIES.**

A. Table 2 below presents the different revenue requirements for full requirements residential and solar PV residential customers from the cost studies that are attached as Exhibit HEO- 5 Original Base Study, Exhibit HEO- 6 Counterfactual Study, and Exhibit HEO- 7 Solar Class Study. Each Exhibit provides the summary of the allocations and the revenue requirement for each class of service. The base study is identical to the filed TEP study with the exception that solar DG customers are treated as a separate part of the residential class. The counterfactual study assumes that solar DG customers were full requirements customers. The solar class study treats solar DG customers as if they were a separate class.

**Table 2**

**Comparative Fixed Cost Revenue Requirements**

**Embedded Cost of Service Studies**

| Study | Residential Full | Solar DG Partial | Total Company |
|---|---|---|---|
| **Base TEP** | **$490,483,998** | **$10,386,841** | **$958,869,144** |
| **Counterfactual** | **$486,146,405** | **$14,724,434** | **$958,869,144** |
| **Solar Class** | **$489,591,785** | **$11,279,053** | **$958,869,144** |
| **Lowest Revenue** | **$486,146,405** | **$10,386,841** | |

The results of these studies are useful in understanding that solar DG causes fixed costs that are significant. The total residential class fixed cost revenue requirement is the same $500,870,839 for the base, counterfactual and solar as a separate class cost studies. The difference in the studies relates to the intra class allocation.

The current annual rate revenue excluding Power Supply charges (the base revenue) for residential solar DG customers is $3,352,194. The subsidy may be calculated as the difference between the revenue and the base cost of service or $7,034,647. The implicit subsidy for fixed costs is just over $729[5] per customer for the 9645 solar DG customers on the lowest fixed cost allocation. That number increases to almost $822[6] when the actual solar class fixed costs are used. In addition to this subsidy, DG customers with net metering and banking have an additional subsidy based on energy costs as calculated in the following section.

**Q. PLEASE EXPLAIN WHY THE THREE STUDIES ARE USEFUL.**

A. Since cost of service is a zero sum methodology, all costs must go to some class and any

[5] Calculated as ($10,386,841 - $3,352,194)/9645= $729

[6] Calculated as ($11,279, 053 - $3,352,194)/9645= $822

change in allocation to one class must be reflected as an opposite change to one or more of the other classes. In order to understand the costs for residential DG customers, they must be separated from the full class. The portion of the residential class costs allocated to solar DG customers as part of that class are shown in the base study. The counterfactual study shows the amount of costs that would be allocated to full requirements customers prior to customers choosing to install solar DG and capture the benefits of net metering. Even though no changes occurred in the class cost and no changes occurred in the fixed costs[7] for utility service to the solar DG customers the solar DG customers are allocated less plant than would be allocated before they chose DG as shown by the counterfactual study. This result is not surprising since one would expect that these customers were larger on average than the average customer. Finally by treating solar DG customers as a class they still get less costs than when they were full requirements customers but the portion of plant allocated to them recognizes there higher class NCP based on delivering excess generation.

**Q. IS IT POSSIBLE TO SHOW HOW COSTS CHANGED BY EACH UNBUNDLED COST CATEGORY?**

A. Yes. Since the cost of service model develops unbundled costs it is possible to show the aggregate revenue requirements by unbundled cost components. Table 3 below provides the revenue requirements for full requirements customers and for Solar DG customers by function excluding energy.

[7] Solar DG customers still have the same distribution facilities and use the same baseload generation to serve night time loads.

**Table 3**

| Comparison of Revenue Requirements by Function | | | | | | |
|---|---|---|---|---|---|---|
| | Base Case | | Counterfactual | | Solar Class Case | |
| Unit Cost Component | Residential RES | SGS SOLAR | Residential RES | SGS SOLAR | Residential RES | SGS SOLAR |
| Procurement Demand | $164,720,747.00 | $3,638,609.00 | $163,255,298.00 | $5,104,057.00 | $164,771,228.00 | $3,588,128.00 |
| Energy | $121,166,960.00 | $2,480,688.00 | $119,904,840.00 | $3,742,809.00 | $122,333,599.00 | $1,314,049.00 |
| MustRun Demand | $23,859,886.00 | $516,489.00 | $23,637,840.00 | $738,535.00 | $23,862,089.00 | $514,286.00 |
| Trans Demand | $53,895,819.00 | $902,438.00 | $53,145,395.00 | $1,652,862.00 | $52,741,699.00 | $2,056,558.00 |
| Distribution Demand | $45,115,282.00 | $755,416.00 | $44,487,115.00 | $1,383,583.00 | $44,149,188.00 | $1,721,510.00 |
| Customer | $55,808,488.00 | $1,432,601.00 | $55,808,488.00 | $1,432,601.00 | $55,808,488.00 | $1,432,601.00 |
| Customer | $25,916,817.00 | $660,599.00 | $25,907,429.00 | $669,988.00 | $25,925,495.00 | $651,921.00 |
| TOTAL Demand | $287,591,733.00 | $5,812,952.00 | $284,525,649.00 | $8,879,037.00 | $285,524,203.00 | $7,880,482.00 |
| Energy | $121,166,960.00 | $2,480,688.00 | $119,904,840.00 | $3,742,809.00 | $122,333,599.00 | $1,314,049.00 |
| Customer | $81,725,305.00 | $2,093,200.00 | $81,715,916.00 | $2,102,589.00 | $81,733,983.00 | $2,084,522.00 |
| Solar Revenue Requirement | | $10,386,840.00 | | $14,724,435.00 | | $11,279,053.00 |

The table shows the embedded cost allocated to solar DG customers under each cost study. As would be expected the counterfactual cost study allocates more cost to solar DG customers because they are treated as full requirements customers. All of this data is useful because it shows the how solar DG customers shift costs to full requirements customers even though in the rate case period there are no changes in fixed costs associated with solar DG and ratemaking is based on cost of service.

**Q. PLEASE PROVIDE THE CALCULATION OF THE COST SHIFT TO FULL REQUIREMENTS RESIDENTIAL CUSTOMERS FROM SOLAR DG CUSTOMERS ON AN EMBEDDED COST BASIS.**

A. Table 4 below provides the cost shift based on the difference in revenue requirements for the base case and the solar class case from the counter factual cost study.

**Table 4**

**Cost Shifts Resulting From Customers Adding Solar DG**

| | A | B |
|---|---|---|
| Unit Cost Component | Solar Class | Base Case |
| | | |
| Procurement | | |
| Demand | $1,515,929.00 | $1,465,448.00 |
| | | |
| Energy | $2,428,760.00 | $1,262,121.00 |
| MustRun | | |
| Demand | $224,249.00 | $222,046.00 |
| Trans | | |
| Demand | -$403,696.00 | $750,424.00 |
| Distribution | | |
| Demand | -$337,927.00 | $628,167.00 |
| Customer | $0.00 | $0.00 |
| | | |
| Customer | $18,067.00 | $9,389.00 |
| TOTAL | | |
| Demand | $998,555.00 | $3,066,085.00 |
| | | |
| Energy | $2,428,760.00 | $1,262,121.00 |

As would be expected, the AED allocation of production is lower and there is a larger embedded cost savings for solar customers when they are treated as a separate class. The energy cost shift results from the lower use of energy and hence a lower allocation of base costs allocated on energy such as fuel inventory costs. Two important factors should be noted. As expected, treating solar as a separate class properly increases the cost of delivery related services based on the higher class NCPs from delivery of power to the system. There is also a slight increase in must run demand that is attributable to the variable nature of solar DG generation.

**Q. WHY DOES THE SOLAR CLASS STUDY ALLOCATE MORE COSTS TO SOLAR CUSTOMERS THAN THE BASE STUDY?**

A. The unbundled cost components are different based on the fact that the AED/4CP cost methodology allocates generation costs using a demand allocation factor made up of weighted average demand and weighted load NCP. The solar class allocation for generation is less than the allocation under the base case. For the demand related portion of the distribution system, the base case under allocates distribution system costs to the solar DG customers because it uses the load demand rather than the actual maximum demand which is based on delivery demand. The different NCP for delivery compared to the residential class coincident NCP for solar DG customers is less than half of the delivery NCP. That difference is based on the difference in the load diversity and the absence of diversity with respect to excess generation. Thus it is the delivery service that establishes the maximum demand on the distribution system. The net result is that the solar class's allocation increases compared to the base case.

**Q. PLEASE DISCUSS THE COST OF SERVICE RESULTS.**

A. Several conclusions are worth noting. First, the total full requirements, residential class, fixed cost of service is higher for the base case and the solar case than if the solar DG customers had not invested in DG. This results from a cost shift within the class to full requirements customers. Second, all three studies produce a customer charge for both full and partial requirements customers of about $18.00 per month. If the company were to analyze the extra costs associated with solar DG associated with record keeping and billing it is likely that the solar DG charge would be above this average level. Third, it is critical to understand cost causation on the distribution system results in higher costs for solar DG even without the consideration of the added costs associated with lower power factor, more frequent voltage control events and other impacts on distribution system costs. Fourth, the evidence is conclusive that there are no avoided distribution costs for TEP and likely none for any utility in Arizona given the solar load shapes. Fifth, the magnitude of the base rate charges for solar customers would be much higher than the energy charges for full requirements customers thus necessitating recovery of the fixed charges in demand charges because the kWh charge under a two-part rate would further distort the solar DG sizing decision.

**Q. WHAT CONCLUSIONS DO YOU REACH FROM THE COST OF SERVICE STUDIES AS THEY RELATE TO SOLAR DG, NET METERING, BANKING AND RATES?**

A. The conclusions related to cost of service are as follows:

1. Solar DG customers must be treated as a separate class of service in the cost study.
2. The two-part rate with net metering cannot ever produce equitable treatment of full requirements customers and solar DG customers who have different demand profiles and load factors.
3. Banking adds to the subsidy that result under current rates and a cost study that reflects cost causation.
4. Rate design must be unbundled so that each utility service is priced separately (the ACC has made a good start on unbundled rates by identifying delivery services and power supply charges but more needs to be done in particular

removing all fuel and variable generating costs from base rates and recovering those costs on a time of use basis) and the rate design must be a multi-part rate to meet the principles of cost causation and matching.

**Q. WHICH COST METHODOLOGY SHOULD BE USED IN FUTURE RATE CASES TO PROMOTE EQUITABLE RATES TO CONSUMERS?**

A. Solar DG residential customers have very different usage characteristics as compared to full requirements residential customers. That is the two groups are not homogeneous and thus need to be treated as separate classes in the cost study. Going forward, the solar residential customers should have rates based on the costs they cause. They should also have separate load research for both load and generation to precisely measure the system impacts of both delivery and production. The minimum system method for classifying distribution customer costs should be used to properly reflect costs caused by customers regardless of load. Setting rates based on costs also means that it is important to send these customers a price signal that creates value for smart inverters. Thus, the demand charges for these customers should be based on kVa rather than kW.

**Q. DOES THIS RECOMMENDATION ALONG WITH UNBUNDLED RATES HAVE ANY NEGATIVE IMPACT ON THE CONSERVATION OF ENERGY SUPPLIED BY THE UTILITY?**

A. No. On the contrary the unbundled rates that reflect cost causation actually result in more efficient conservation of utility energy and capacity than the current tiered rate structure. The tiered two-part rate results in energy cost savings to the customer that are far more than the actual savings to the utility. As a result, utility resources are misused resulting in lower energy consumption but also lower savings in capacity. This actually works against the efficient use of resources contrary to the very definition of conservation which is defined as "Exploitation, improvement, and protection of human and natural resources in a wise manner, *ensuring derivation of their highest economic and social benefits on a continuing or long-term basis*."[8] (Emphasis added.) The unbundled rates based on marginal costs to the extent consistent with revenue requirements represent the best option to promote conservation efficiently. Further, using rates based on this cost of service study, eliminating both net metering and banking, using a monthly avoided cost cashout for excess energy or in the alternative using a buy all sell all that has a current avoided cost value of solar will provide the most efficient platform for integrating solar DG into the utility supply portfolio.

**Q. DO THE UNBUNDLED RATES RESULTING FROM THE COST STUDY PROVIDE RATES THAT ARE JUST AND REASONABLE AND NOT UNDULY DISCRIMINATORY?**

A. These rates meet the just and reasonable test for rates and treat customers with the same load characteristics equally. That does not occur under two-part even if the class is relatively homogeneous. The reason is straight forward. The energy under current rates recovers customer costs not recovered in the customer charge on a per kWh basis meaning that any customer with annual usage larger than the average pays a higher share of the customer costs and subsidizes customers who use less than the average. A similar issue relates to the recovery of demand related costs which are spread to the kWh charge based on the class average load factor. Any customer, large or small, with a better than class average load factor pays a larger share of the demand related fixed costs while lower load factor customers pay less than the costs they cause. It is not unusual for residential load factors to vary significantly with the lowest load factors being less than half the highest load factors. Based on the UNS Electric load research data, the NCP load

[8] http://www.businessdictionary.com/definition/conservation

factors differ for subgroups of the residential customers ranging from about 19% to 49% per subgroup. For a five dollar cost per kW per month, the low load factor charge per kWh would be $0.036 per kWh while for the highest load factor the charge would be $0.014 per kWh or about 39% of the charge for that lowest load factor subgroup. Using a demand charge and a cost based customer charge eliminates this difference. I should also note that the tiered rates implicitly assume that load factor declines with increasing kWh usage. In fact, the opposite is the case as larger use customers have higher load factors than lower use customers on average. This means that there are also intraclass cost subsidies in current rates.[9]

## VI. ALLOCATION OF ENERGY COSTS - COMPARISON OF RESIDENTIAL FULL AND PARTIAL REQUIREMENTS CUSTOMERS

**Q. WHY IS IT NECESSARY TO ALLOCATE ENERGY COSTS OUTSIDE THE COST OF SERVICE STUDY?**

A. In a traditional cost of service study the basic assumption is that all classes use energy in the same pattern as the system with the only differentiation in the level of losses associated with voltage level of service. While this assumption may not be matched for each class of service, there is no systematic difference within a class of customers. The customers with solar PV under net metering with banking use energy far differently than full requirements customers. To understand this issue we only need to look at the difference in the system load pattern and the output of solar DG. Exhibit HEO – 1 illustrates how solar output does no match the system load profile. Instead, solar output is most likely to be at its maximum in lower load periods. While the correlation of load and cost is not perfect, the solar production is lower than rated capacity or zero in some

[9] This is also consistent with findings in California related to intra-class cost subsidies under inverted rates.

of the highest cost periods and is highest in some of the lowest cost periods. This means in the low load periods when solar meets the customers' requirements and sends excess energy back to the system the value of that energy is lower than in some high load, high cost periods when solar customers must rely on the grid to supplement the energy produced by the solar DG. If this issue was only consumption at night when costs are lower the matching between the costs imposed at night and when the power is returned to the grid there would be better matching of costs after adjusting for losses. That is not however the sole issue. Simply, the average marginal cost in non-solar hours is actually greater than the average marginal cost when solar is operating. Given the unique and coincident patterns of solar DG there is also a mismatch of avoided costs and average costs that allows for arbitrage through storage that results in additional cross subsidy for the energy component of costs. The arbitrage subsidy is potentially significant and cannot be evaluated through the embedded cost study since it only deals with average costs. There is even a subsidy in the difference between the average cost of energy and the lower marginal cost avoided when solar customers use their own generation. The largest subsidy is related to the full cost reimbursement for excess as compared to the avoided marginal costs.

**Q. DOES THE SEPARATE ENERGY COST ANALYSIS ALLOW FOR AN ASSESSMENT OF THE UNIQUE SOLAR LOAD PATTERNS IMPACT ON THE EFFICIENT OPERATION OF THE UTILITY GENERATION?**

A. It does to the extent that the system has enough solar load and output to actually track the ramp rates and other operating requirements. In any event, the energy cost study allows for an analysis of avoided costs and the actual average cost for solar load as compared to full requirements customers. This is useful for assessing the actual energy related subsidies included in the energy component of rates.

**Q. HAVE YOU PREPARED AN EXHIBIT THAT PROVIDES THE RESULTS OF THE ENERGY COST STUDY?**

A. Yes. Exhibit HEO – 8 Energy Cost Study is attached. That exhibit uses hourly loads and hourly marginal costs to calculate avoid costs for solar DG customers, marginal costs for full requirements load, and the energy cost subsidies that result from net metering. The study uses actual 2015 billed data from TEP solar customers along with 2015 hourly marginal and embedded costs by hour to make the calculations.

**Q. PLEASE SUMMARIZE THE RESULTS OF THE ENERGY COST STUDY.**

A. The energy cost study shows nearly $1.4 million dollars of energy cost subsidies that result from energy arbitrage (buying higher marginal cost energy and returning the energy in lower marginal cost periods), energy excess sale (selling excess energy back to the company at average energy cost when marginal cost is less than the average cost) and energy credit for solar DG used on premise (the difference between the average power costs and the marginal avoided power costs). The total subsidy for these three subsidies is $144.72 per solar DG customer. These subsidies are also significant larger than one would expect from using average energy costs within relative homogeneous class of service.

**Q. PLEASE EXPLAIN HOW THE ENERGY SUBSIDY FOR EXCESS GENERATION WAS CALCULATED.**

A. The calculation is a three-step process. In the first step the marginal hourly energy cost for load is calculated ($26.97 per MWh). In the second step the marginal avoided cost of excess energy is calculated ($24.62 per MWh). The net of these two values is the arbitrage associated with consumption in high cost hours with no adjustment for losses in the measurement of the excess energy. The full energy subsidy may be calculated in step three as the difference between marginal energy cost of load ($26.97) and average system hourly energy costs for the excess energy component ($42.39 per MWh) plus previously calculated arbitrage value. Exhibit HEO – 8 Table 2 provides the calculations for average hourly marginal cost.

**Q. WHAT CONCLUSIONS FOLLOW FROM THIS ANALYSIS?**

A. This analysis confirms and supports the conclusions related to solar DG, net metering, banking and rates above. Net metering results in large and persistent subsidies that cannot be justified particularly when solar DG is not the least cost solar power option.

## VII. SOLAR DG BENEFITS - NEAR TERM AND LONG TERM DIFFER

**Q. WHY IS IT NECESSARY TO DISTINGUISH BETWEEN NEAR TERM AND LONG TERM BENEFITS?**

A. For cost studies and for rates regulators use a test year to determine revenue requirements based on cost of service. Thus a rate case may be characterized as a near term analysis. In an IRP analysis or in a long term contract benefits are evaluated over a long term horizon but variable rates are not set on that long term forecast. The result is that it is necessary from an economic and efficiency basis to consider benefits and their rate impacts as in the near term context. In essence the fundamental problem with the avoided cost rates used in PURPA contracts in the 1980's was the levelization of both the fixed cost component (avoided capacity costs) and the forecast and levelization of future energy costs into a single payment stream. The PURPA contracts had oil as the marginal fuel in the Northeast and oil prices at over $100 per barrel as early as the 1990s. These oil prices did not materialize and gas became the marginal fuel resulting in avoided costs far below the fixed price payments in these contracts. The simple solution for just and reasonable rates is to separate the components. The energy component should be based on the short term test year marginal costs that underlie the test year revenue requirements. The capacity avoided costs are by their nature long-term costs and those should be based on the net present value of the avoided costs in the future. For solar DG the avoided capital cost in any year will vary with the expected long-term growth of the utility, technological changes in the alternative sources of power including solar options, the impact of storage technology on avoided capacity costs and so forth. From an economic perspective net metering with or without banking cannot adequately address these issues. There is no reason to believe that marginal costs are correlated with the average costs that make up revenue requirements for at least the following reasons:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs.
- Additions to the system are lumpy and as a result utilities optimal additions often include more capacity than the marginal change in the variables that reflect cost causation such as customers, CP demand, class NCP demand and customer NCP demand.

Given these factors even a sound and efficient multi-part rate cannot adequately reflect the avoided capacity related costs. A properly developed marginal cost based seasonal TOU energy charge will result in a better matching of energy costs and benefits with in the rates and creates no need to include future costs that are highly uncertain as part of the current price signal. By including the future costs of energy in the analysis of current benefits there is an intertemporal subsidy that provides no benefit for current full requirements customers but rather results in social welfare losses for all non-DG customers in the current period.

For the avoided capacity cost component, if any, those costs should be fixed at the time the solar DG is added to the system and established in a tariff provision that applies to the particular vintage of installations. The avoided DG capacity payment would be most efficient if it were determined by a market process such as competitive bidding for DG capacity in a tranche. The solar DG would bid a capacity payment for the peak hour or hours output of the facility. The winning bids would be certified by the utility as at or below the avoided capacity costs. The regulated version of this process would be an annual avoided cost determination hearing and setting the rate at the avoided cost. In either case the rate would be fixed for the 20 year life of the facility. Obviously, this latter method is less efficient since it is a fixed price and not a competitive bid price that would result in the least cost options for customers and promote bidders seeking to be more efficient and productive to maximize their return.

**Q. HOW WOULD A CAPITAL CREDIT WORK IN PRACTICE?**

A. The capital credit would be assigned to the premise and paid annually based on the amount bid or the amount calculated at the time of the contract with a stream over the entire period of the contract. As a practical matter this is the same pattern of costs for a utility developed asset. It also requires that the solar DG produce output for the term of the contract or lose the capacity payment just as a utility would lose rate base treatment for an asset no longer used and useful for a utility. The payment of a levelized total cost is inconsistent with rates and creates issue of intergenerational equity and potential excess payments since solar DG has no obligation to operate at rated capacity over its useful life. In fact capacity values will decline over time. Further, there is no guarantee that current solar will be operating over its useful life and no obligation on the part of a solar DG customer to make the necessary repairs to maintain the capacity particularly when the premise changes ownership. This all suggests that capacity payments, if any be made separately from retail rates and not be the result of net metering which causes both excess payment for the solar DG in the near term and even over the useful life as the value of DG declines as penetration increases and as the asset ages.

**Q. WHY IS THE DISTINCTION BETWEEN LONG TERM BENEFITS AND SHORT TERM BENEFITS PARTICULARLY IMPORTANT IN SETTING POLICY FOR SOLAR DG?**

A. This distinction is critical to the fundamentals of competitive market outcomes, economic efficiency and just and reasonable, non-discriminatory rates. One of the purposes of regulation is to recognize that competitive market outcomes cannot result from services that are best provided by a monopoly service because of scale economies. As noted above, the provision of utility service is best provided in a mixed monopoly and competitive model. As a result of this new model the monopoly portion of the model should only be the wires component of the utility for a fully unbundled utility with no provider of last resort or balancing authority requirements. Generation is a competitive self-service option and solar generation in any form must compete with conventional generation and with other renewables and even different types of solar projects to be part of the least cost mix for meeting state mandated renewables goals. The solar generation alternatives are numerous and use different technologies that should be considered in a competitive market not a market supported by subsidies that bear no relationship to economically efficient marginal cost based price signals.

The only way to provide for efficient outcomes is to separate the capital and the energy components of the payment stream. Energy payments based on short run costs is the exact same way that utility generation recovers energy costs. Over the life of some power plants that energy cost moves up and down with competitive input prices. There is no economic reason that solar DG should be any different than a competitive power plant that bears the fuel cost risk in the short term. Further, the capital cost payment based on the avoided cost at the time of the contract is the intrinsic economic cost of capital over the life of the asset. This mixture on short term energy and long term capital will allow both customers and society in general to benefit from an economically efficient mix of generation resources.

## VIII. <u>THE OUTCOME FOR NET METERING MUST MEET THE OBJECTIVES OF PURPA</u>

**Q. PLEASE EXPLAIN HOW THE PURPA OBJECTIVES ARE RELATED TO NET METERING.**

A. Subtitle A of PURPA provides general provisions that are tied to the Retail Regulatory Policies for Electric Utilities in Title I of the original Federal statute. The net metering provision amended Section 111 (d) that established certain standards for review subject to the full requirements of Section 111 Consideration and Determination Respecting Certain Ratemaking Standards. The Energy Policy Act of 2005 amended Section 111 (d) to provide for three new standards for consideration including a net metering standard. Section 101 Purposes of the law was not amended during the process of amending Section 111 on several occasions including the amendment that added net metering. The Purposes of the law are as follows: "to encourage (1) conservation of energy provided by electric utilities, (2) optimal efficiency of electric utility facilities and resources, and (3) equitable rates to electric consumers. Section 111 (a) Consideration and Determination provides that approval of the standards must consider whether adoption of the standards carries out the "purposes of this title". Those purposes for the title are contained in Section 101 as noted above. Thus Section 111 (a) sets the standard for review for Section 111 (d) as it relates to the purpose of PURPA. Neither Section 101 nor Section 111 (a) has been amended with respect to net metering. Section 111 (a) also notes that the Section supplements applicable state law. Thus net metering must meet the purposes of PURPA, the most important of which in this context is equitable rate for consumers since this is a ratemaking concept. It is also important that the other two purposes be evaluated as a matter of policy. Thus any decision related to net metering must identify how these purposes are met.

**Q. PLEASE DISCUSS THE EQUITABLE RATES PROVISION.**

A. Equitable rates are not defined in PURPA. However, the concept has been defined over the years by regulators, legislators and the courts with terms like just and reasonable rates, non–discriminatory rates and rates that manifest the cost causation principle and the matching principle noted above. Where rates reflect cost causation it is reasonable to conclude that the rate is equitable. In the context of net metering rates are equitable only if the rate design reflects cost causation and the value of the solar energy produced matches current avoided costs for the rate effective period.

Rates for the monopoly portion of the services required by solar DG must be fully unbundled and designed so that when a customer chooses to use a monopoly service the customer cannot avoid any of the fixed costs caused by the customer's choices of services. Obviously, net metering with volumetric recovery of fixed costs cannot produce equitable rates. When kWh banking is allowed the mismatch of avoided costs and net metering credits is further exacerbated because the energy costs when the customer consumes supplemental power is during high load periods and when solar DG cannot produce power. The hours when solar cannot produce power include both low load and lower cost periods in the summer and part of the winter. In other winter hours solar DG is not available in higher cost periods and uniformly produces maximum output for delivery to the utility in low load and low cost periods. The net result is, as discussed above, solar DG virtual storage arbitrage from both the timing of excess deliveries and the failure to account for the extra losses under this transaction.

**Q. DO THE NET METERING PROCEDURES ADOPTED BY THE ACC COMPLY WITH THE EQUITABLE RATES PURPOSE OF PURPA?**

A. There are inequities in all of the transactions that occur under net metering. Specifically, solar DG customers pay a lower portion of the fixed costs of the unbundled services they use than do customers who use the same unbundled services in a full requirements service package. Solar DG customers are also likely to have higher costs than their full requirements counterparts because of costs they cause that are not tracked such as higher losses from the low power factor, the impact on system dispatch particularly related to ramp rates and higher spinning and operating reserves, and the higher losses they cause during low load periods. For recovery of fixed costs associated with delivery service, the kWh rate with a low fixed charge under recovers costs for solar PV as well. In sum, the current arrangement does not produce equitable rates.

**Q. PLEASE EXPLAIN THE PURPOSE OF OPTIMAL EFFICIENCY OF ELECTRIC UTILITY FACILITIES AND RESOURCES AS IT RELATES TO NET METERING.**

A. It is difficult for solar DG to use a system designed solely for delivery of power from higher voltage transmission to lower voltage delivery service levels to use the current resources efficiently. Instead, the issue should be addressing these issues in optimal efficiency related to a reconfigured, least cost system. For example, where the costs for upgrading the system can be avoided by interconnection requirements, solar DG customers should bear these system related costs. This could include for example requiring smart inverters for all DG facilities. It would also require a provision that where excess generation causes higher transformer loadings or more flexible transformers solar customers should pay those higher costs. Where the system must invest in facilities to use the sunk cost portion of the system efficiently those costs should be directly assigned to the solar class of customers. Efficient use of resources must also address the generation mix issues ultimately in determining the least cost efficient configuration of the system.

## IX. CONCLUSIONS AND RECOMMENDATIONS

**Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.**

A. I reach the following conclusions based on the evidence I have provided:

1. Solar DG customers must be treated as a separate class of service in the cost study.
2. The two-part rate with net metering cannot ever produce equitable treatment of full requirements customers and solar DG customers because they have different demand profiles and load factors.
3. Banking adds to the subsidy that result under current rates and a cost study that reflects cost causation.
4. Rate design must be unbundled so that each utility service is priced separately and the rate design must be a multi-part rate to meet the principles of cost causation and matching.
5. The solar DG subsidy for TEP is currently more than $8 million and if solar is treated correctly as a separate customer class the subsidy is over $9 million.

6. The maximum demand of solar customers on the utility system occurs in March or April when solar DG pushes kWhs back onto the system with no natural time diversity.
7. Current rate treatment for solar DG does not produce equitable rates for all customers.
8. There are more efficient, least cost renewable energy resources available other than rooftop solar DG and rooftop should compete with those resources.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

A. I make the following recommendations:

1. Utility cost studies should be filed to include solar DG as a separate class of service.
2. Cost studies should use the minimum system to develop the unit customer costs to be recovered in the customer charge.
3. The NCP allocation factor for solar DG customers should be the greater of the load or the delivery NCP to reflect the maximum demand on delivery resources.
4. Both sales to customers and delivery from customers should be adjusted for losses.
5. Markets should be used to determine the value of DG resources since self-generation and power purchases from DG and utility scale resources are competitive options.
6. All customer rates should be properly designed multi-part rates that recognize cost causation for unbundled services.

**Q. DOES THIS COMPLETE YOUR TESTIMONY?**

A. Yes.

# Attachment A

## DR. H. EDWIN OVERCAST

### *Educational Background and Professional Experience*

Dr. Overcast graduated cum laude from King College with a Bachelor of Arts Degree in Economics. He received the Doctor of Philosophy Degree in Economics from Virginia Polytechnic Institute and State University. His principal fields of study included Economic Theory, Public Finance and Industrial Organization, with supporting fields of study in Econometrics and Statistics. He has taught courses at both the graduate and undergraduate level in Microeconomic Theory, Managerial Economics and Public Finance. In addition, he has taught courses in Mathematical Economics, Economics of Regulation and Money and Banking. While a faculty member at East Tennessee State University, he was appointed to the Graduate Faculty and subsequently directed thesis programs for graduate students.

In 1975, he joined the Tennessee Valley Authority (TVA) as an Economist in the Distributor Marketing Branch. He held successively higher positions as an Economist in the Rate Research Section of the Rate Branch and was ultimately Supervisor of the Economic Staff of the Rate Branch.

In May of 1978, he joined Northeast Utilities as a Rate Economist in the Rate Research Department and was promoted to Manager of Rate Research in November 1979. In that position, he was responsible for the rate activities of each of the operating companies of Northeast Utilities: Western Massachusetts Electric Company, Holyoke

Water Power Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, and the Hartford Electric Light Company.

In March 1983, Dr. Overcast became Director of the Rates and Load Research Department of the Consumer Economics Division of Northeast Utilities. In this position, Dr. Overcast directed the planning of analyses and implementation of system-wide pricing and costs for regulated and unregulated products and services of Northeast Utilities. As part of that responsibility, Dr. Overcast represented the system companies before state and federal regulators, legislative bodies and other public and private forums on matters pertaining to rate and cost-of-service issues.

Dr. Overcast represented Northeast Utilities as a member of the Edison Electric Institute (E.E.I.) Rate Committee and the American Gas Association (A.G.A.) Rate Committee. While serving on those committees, he was the Rate Training Subcommittee Chairman of the A.G.A. Rate Committee. He has been an instructor on cost-of-service and federal regulatory issues for the E.E.I. Rate Fundamentals Course and the E.E.I. Advanced Rate Course. Dr. Overcast also represented Northeast Utilities as a member of the Load Research Committee of the Association of Edison Illuminating Companies.

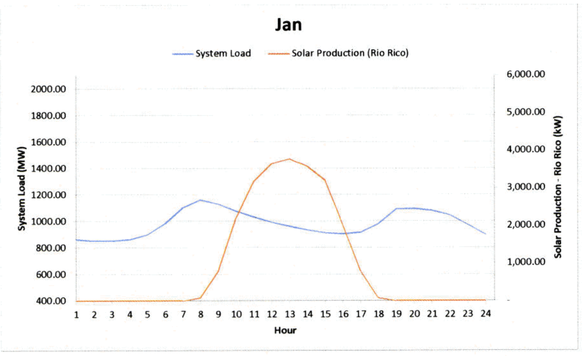
In March 1989, he joined Atlanta Gas Light Company as Director - Rates and was promoted to Vice President - Rates in February 1994. In November 1994 he became Vice President - Corporate Planning and Rates and was subsequently elected Vice President - Strategy, Planning and Business Development for AGL Resources, Inc., the parent company of Atlanta Gas Light Company. His responsibilities in the various rate positions included: designing an administering the Company's tariffs, including rates, rules and regulations and terms of service. He represented the Company before regulatory commissions on rate and regulatory matters and oversaw the preparation of the Company's forecast of natural gas demand. He was responsible for planning activities relating to the regulated businesses of the Company. He developed strategy for both regulated and unregulated business units, monitored markets for new products and services and identified potential new business opportunities for the Company.

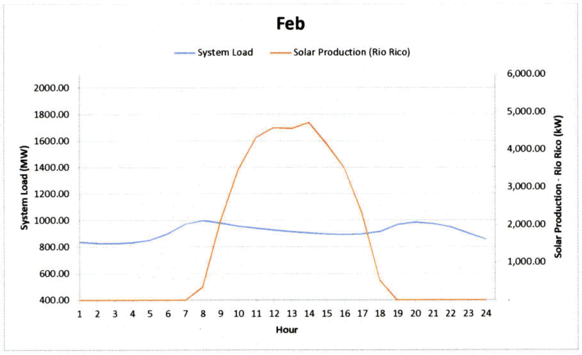
Dr. Overcast has previously testified in rate cases and other proceedings before the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities, the Georgia Public Service Commission, the Montana Public Service Commission, the Missouri Public Service Commission, the Kansas Corporation Commission, the Arkansas Public Service Commission, the Corporation Commission of Oklahoma, the Ohio Public Utilities Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, the Michigan Public Service Commission, the Public Service Commission of Maryland and the Tennessee Regulatory Authority and the Federal Energy Regulatory Commission. In Canada, he has testified before the Ontario Energy Board, the British Columbia Utilities Commission, the New Brunswick Energy and Utilities Board and the Alberta Energy and Utilities Board. He has also testified before the subcommittee on Energy and Power of the U.S. House of Representatives and various committees of the Georgia General

Assembly.

Dr. Overcast joined R. J. Rudden Associates, Inc. as Vice President in September 1999. R. J. Rudden Associates became a unit of Black and Veatch in January of 2005. At that time he became a Principal of the EMS Division, he is currently a Director of Black and Veatch Management Consulting, LLC.

# Exhibit HEO - 1


Jan
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour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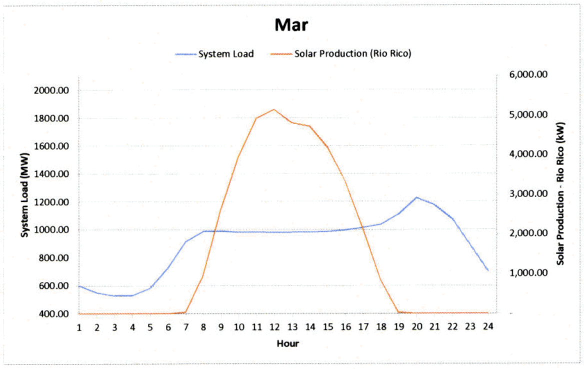
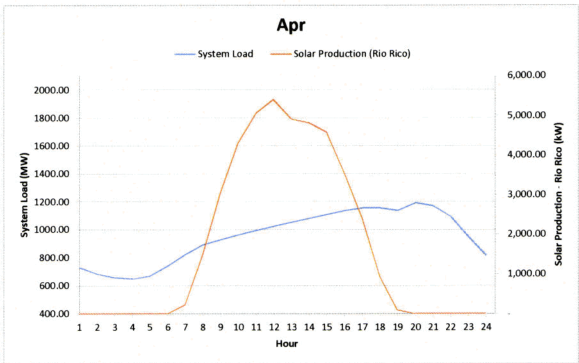
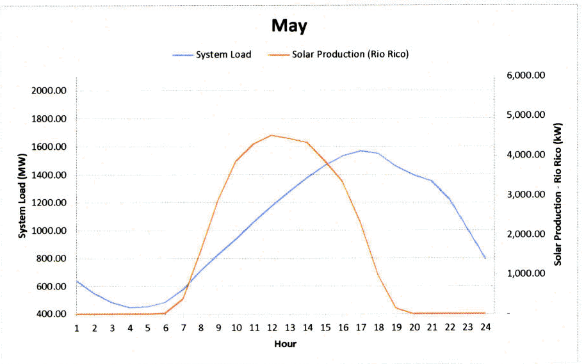
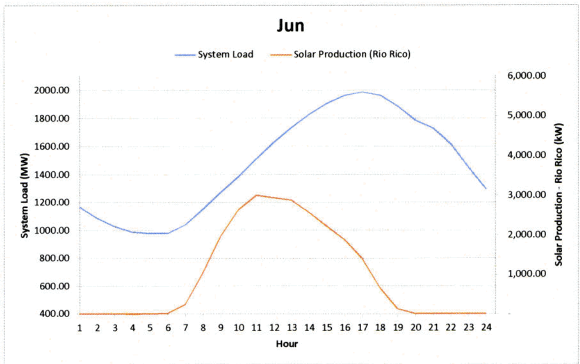
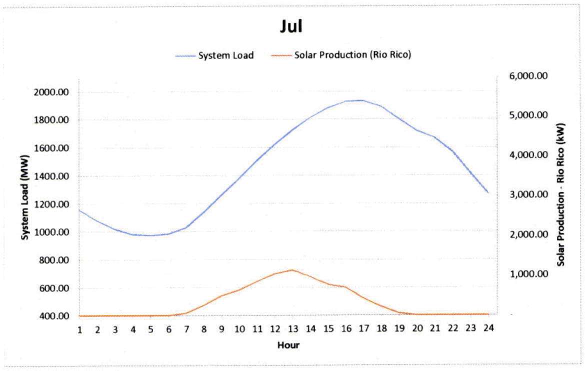
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

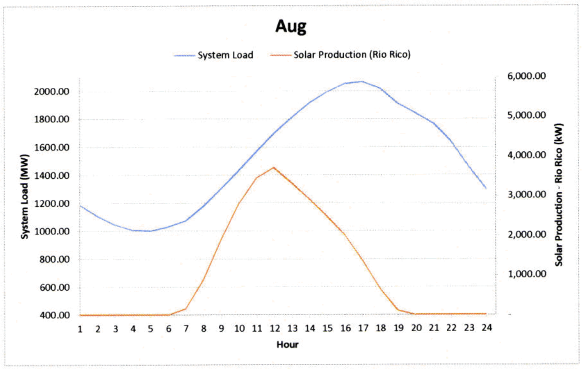

Mar
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

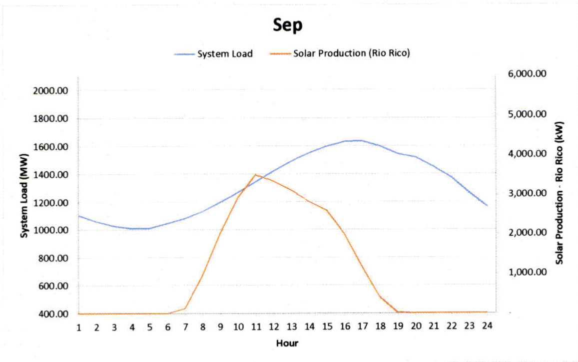

Apr
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

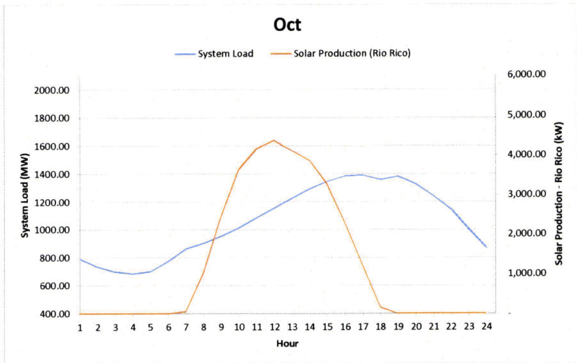

May
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

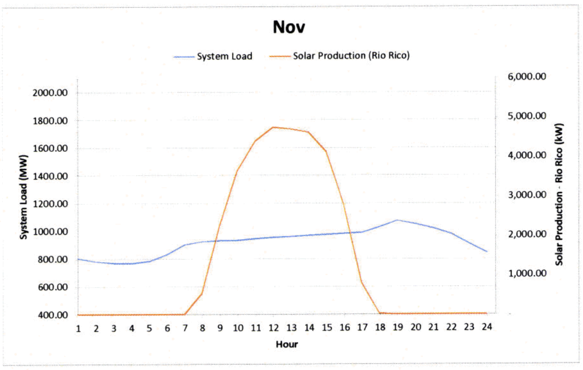

Jun
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

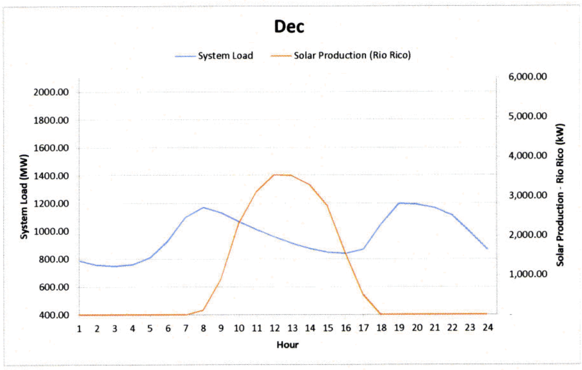

Jul
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Aug
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

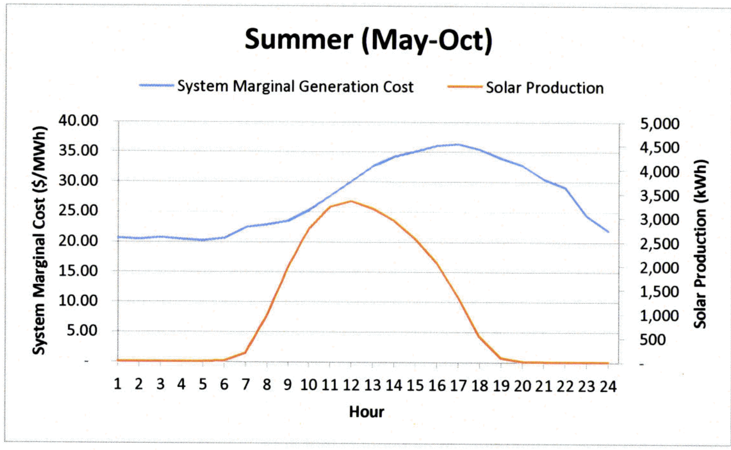

Sep
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

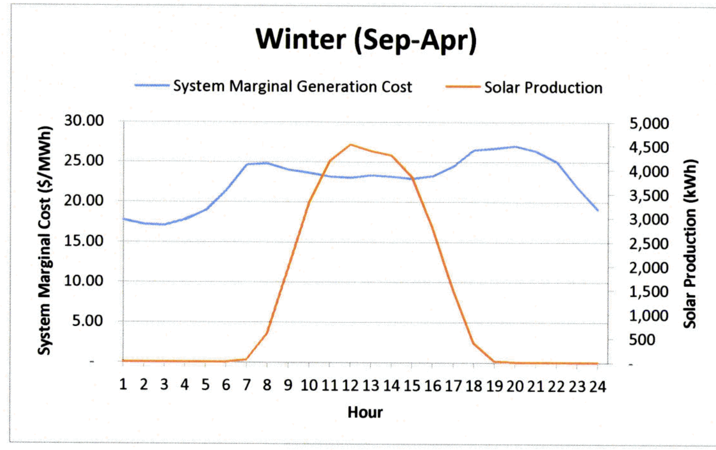

Oct
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Nov
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Dec
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

# Exhibit HEO - 2


Summer (May-Oct)
System Marginal Generation Cost
Solar Production
System Marginal Cost ($/MWh)
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
-
Solar Production (kWh)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


Winter (Sep-Apr)
System Marginal Generation Cost
Solar Production
System Marginal Cost ($/MWh)
30.00
25.00
20.00
15.00
10.00
5.00
-
Solar Production (kWh)
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

# Exhibit HEO - 3

**Distribution Planning and Engineering**

# Residential Solar Generation Losses Memorandum

**To:** Jones, Craig; Dukes, Dallas;

**From:** Brandon Knight/Nate Palma

**CC:** Bustamante, Ana; Lindsey, Chris; Sandoval, Donovan; Fleenor, Chris; Taylor, Jim

**Date:** February 3, 2016

**Re:** Residential Solar Generation Loss Study

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## Background

Residential Solar Generation installations are becoming more prevalent on TEP's power distribution system and like all generation, losses account for a portion of the production within TEP's system. Typically, solar can reduce losses during high demand times by lowering transformer loading and reducing current but there are times when solar does the opposite and can increase loading on a transformer. The highest values of losses associated with residential solar generation occur when the distribution system's demand is at noon peak and solar production is at its noon peak.

During the month of March, the demand on TEP's distribution network is at its minimum. Solar production peaks have been documented to reach its peak production at 12pm. Therefore, the data from 20 feeders (small sample size) within TEP's distribution system was analyzed over the entire month of March at 12pm to determine the typical residential transformer loading to determine the average consumption of each house in a typical network configuration. The configuration for these loss approximations is the same example given to Black and Veatch for the TEP Rate Case with these standard assumptions: 1) all cable is 1/0 underground 2) eight homes served off a 50 kVA transformer 3) cable lengths of 400' primary cable connecting each transformer, 100' of secondary cable connecting to each pedestal, and 75' of service cable connecting to the customer/meter.

TEP has outlined three cases to demonstrate the losses of solar generation on TEP's distribution system. Each case uses the typical network configuration of 8 homes on a single 50 kVA transformer; TEP will illustrate in each diagram in the pages to follow the amount of rooftop solar that either 1, 2, or 3 houses produce ( 7 kVA of generation apiece). Transformer loading percentages are a good indication of whether losses will be higher or lower at any given time. If a transformer is lightly loaded, there will be less current flowing across the line. Therefore, when load is much lower, the solar generation production can actually increase the loading percentage of the transformer and increase the losses on the system.

Solar generation losses on the system were approximated using the cable impedances along with the typical transformer impedance values, and the associated current along each branch. The current was approximated using the typical demand values for each house found in March at 12pm, and the kVA on each branch due to generation.

## Typical loading in March at 12 PM with no Solar Generation

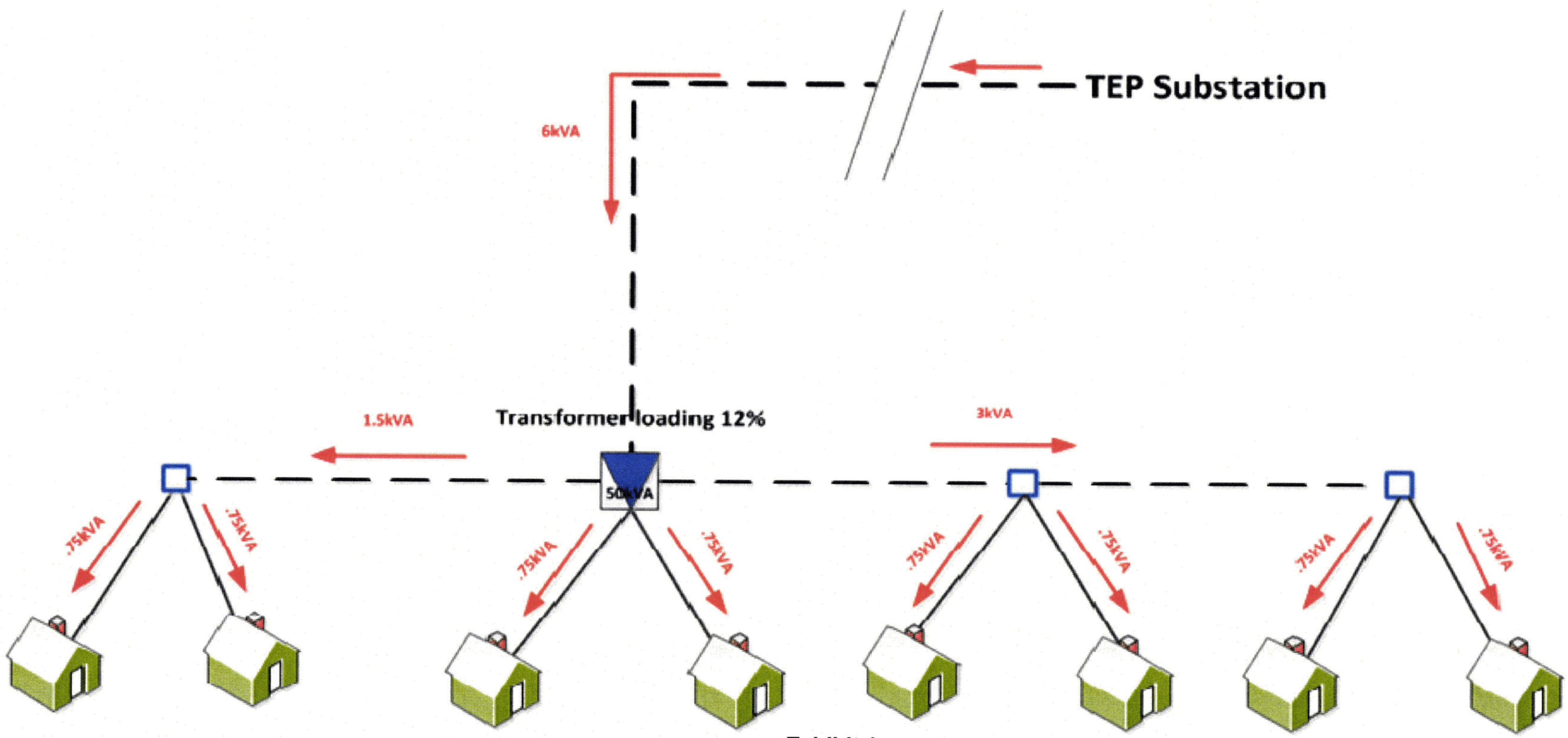



**Exhibit 1**

Exhibit 1 is the typical residential configuration present within TEP's distribution system. This configuration consist of 8 residential customers being served from a 50kV transformer. To find the average loading of the transformer in March at 12pm where solar production would be at its peak, DP&E collected data from 20 feeders. The average loading of the transformers at this time was found to be 12%.

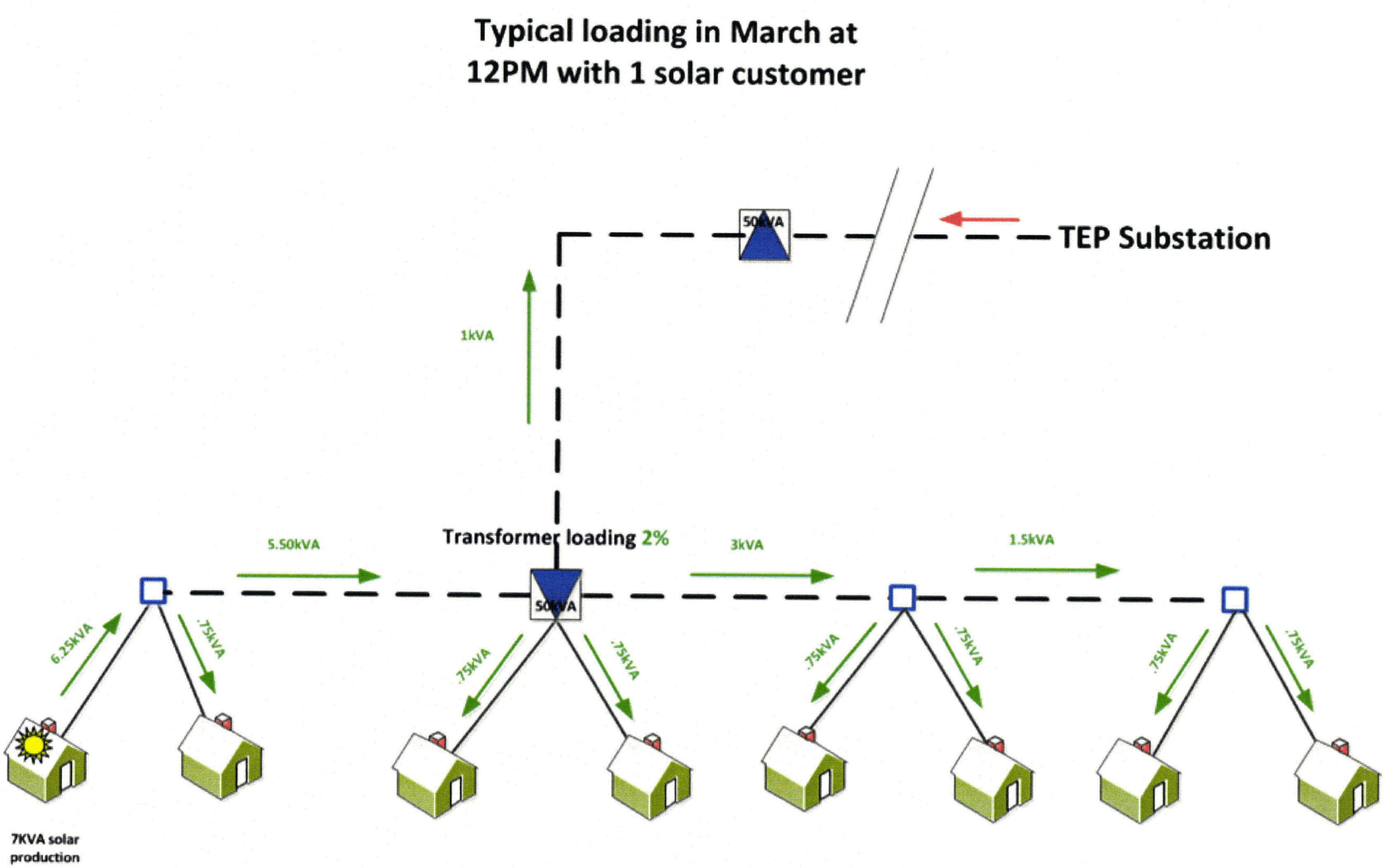
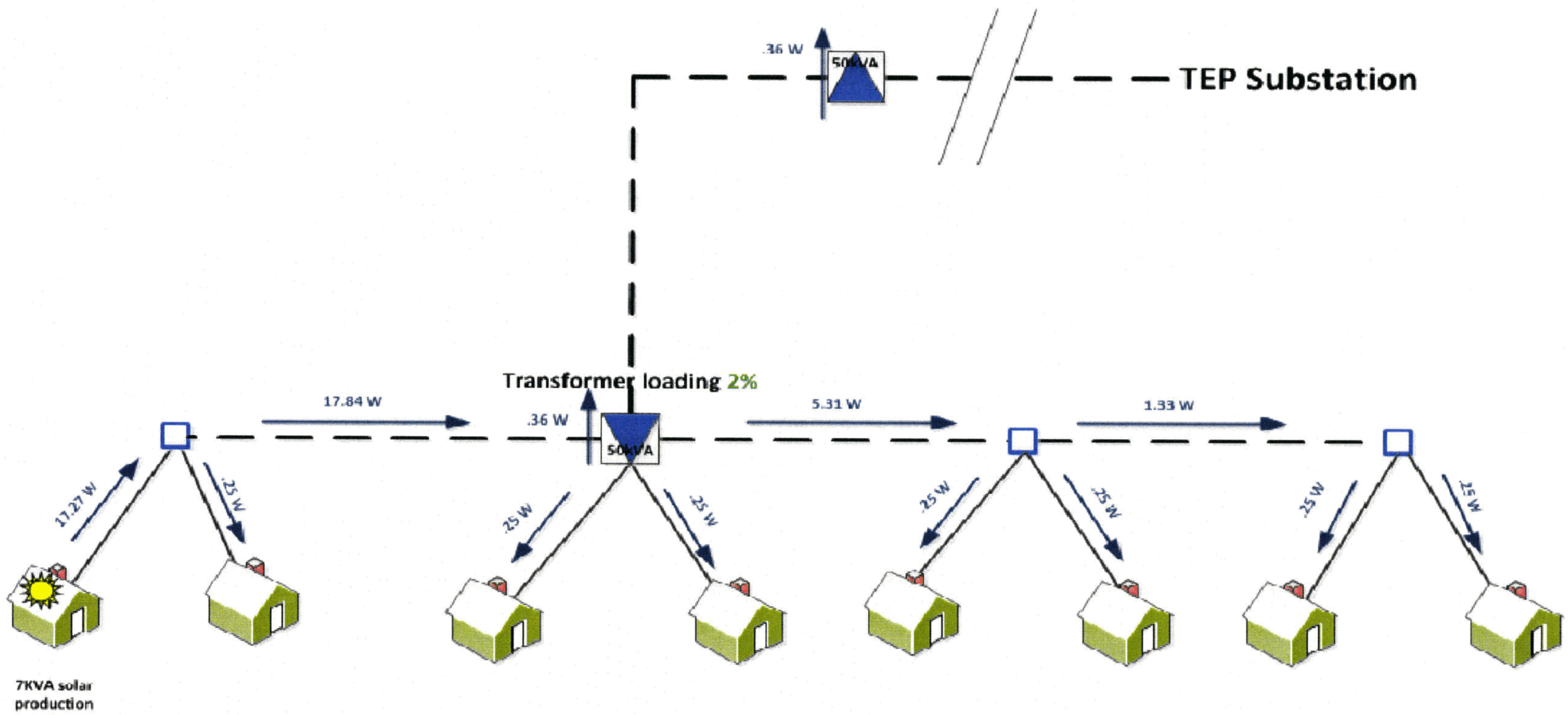



**Exhibit 2**

Exhibit 2 demonstrates the effects one house with solar generation can have on TEP's system. The green power flow arrows are the results of 7kVA of residential solar generation.

## Solar Generation losses associated with 1 house producing 7kVA at daytime minimum




**Total Solar Generation Losses = 44.20W**

**Exhibit 3**

Using the typical transformer impedance and line impedance of this configuration, losses from the solar generation were calculated. The formula used for the loss calculations was $P=I^2R$ where $I$ is the amps across and $R$ is the magnitude of the impedance.

## Typical loading in March at 12PM with 2 solar customers

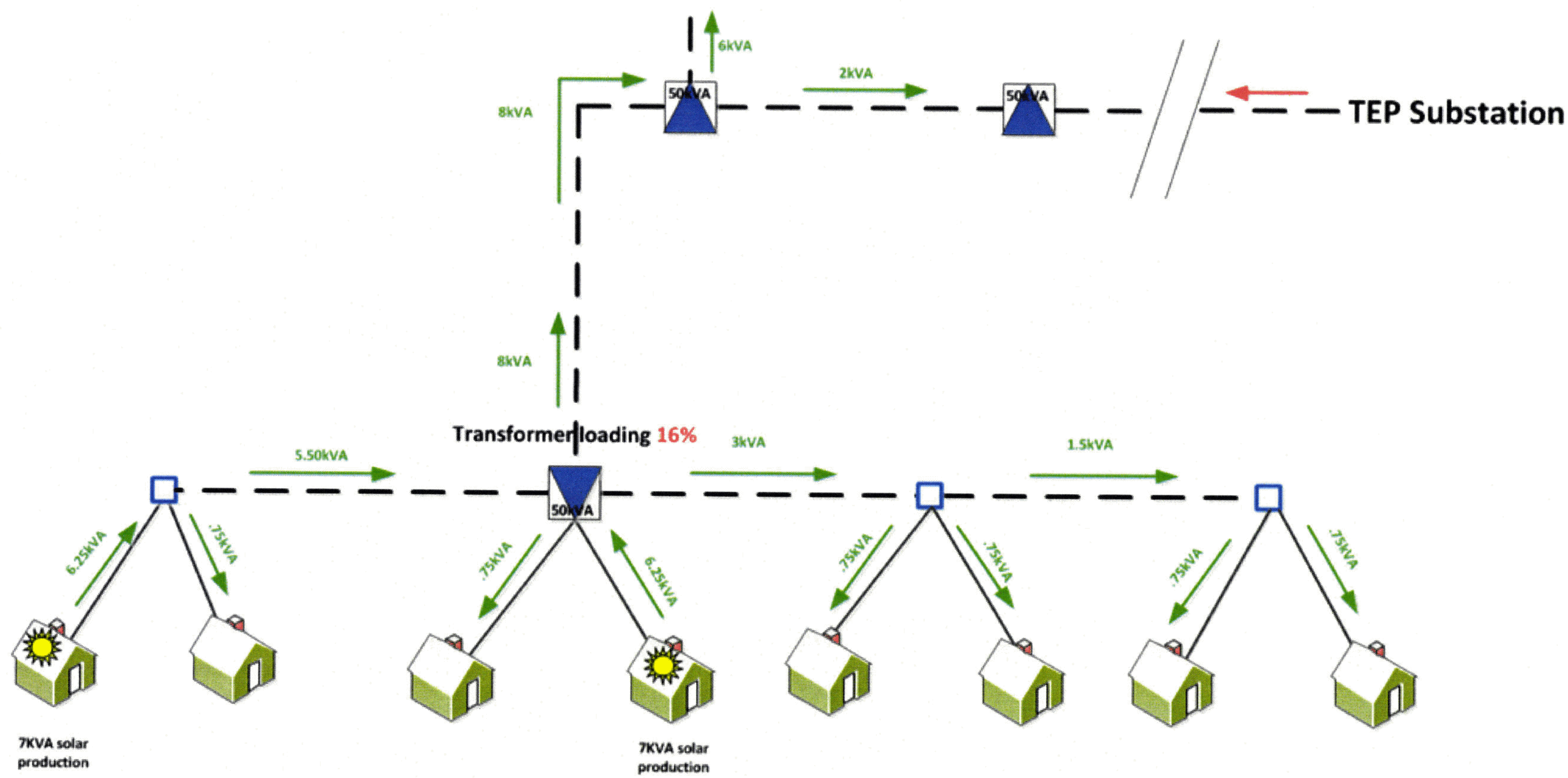
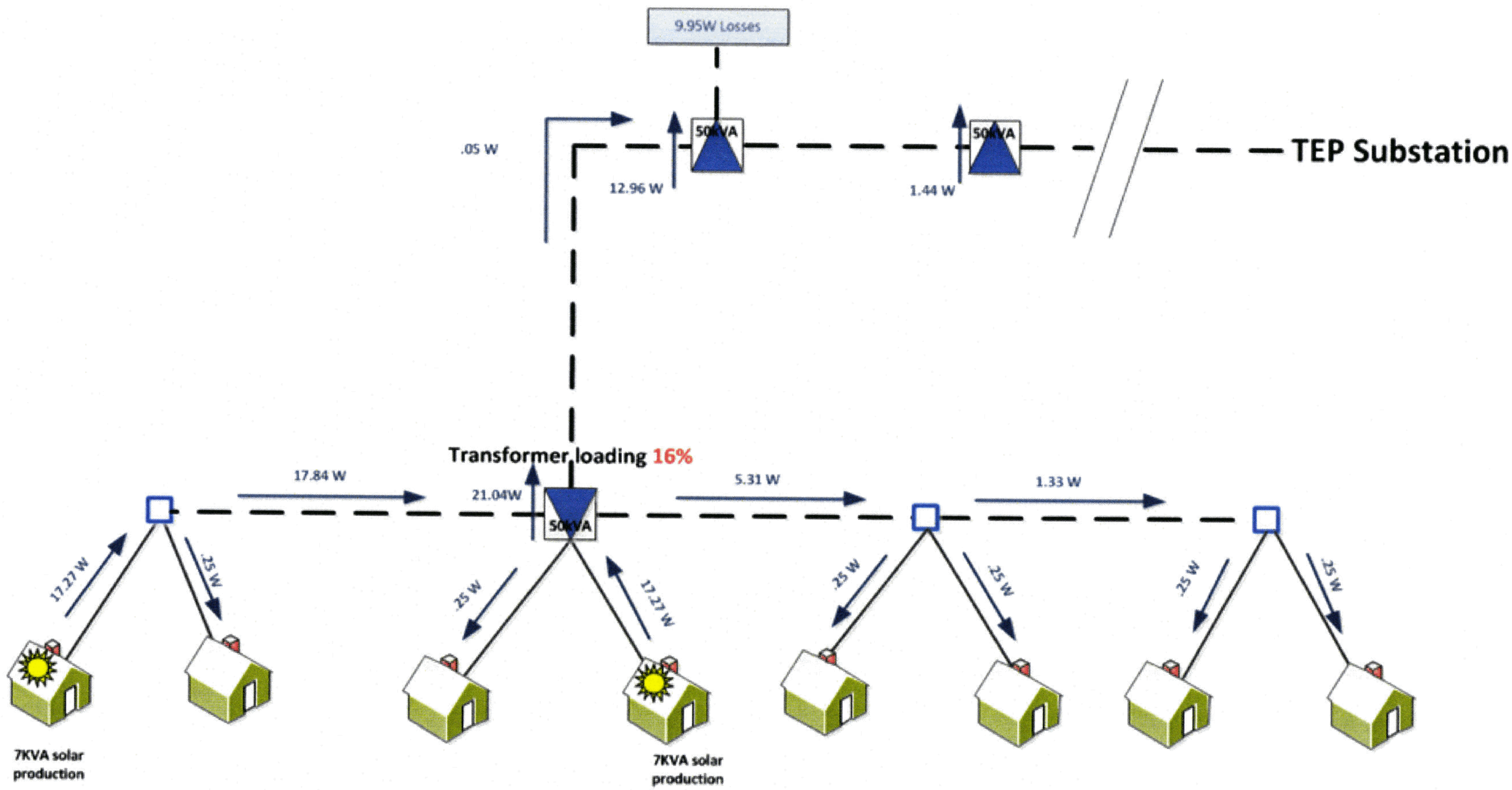



Exhibit 4

# Solar Generation losses associated with 2 houses producing 7kVA at daytime minimum




**Total Solar Generation Losses = 107.95W**

Exhibit 5

## Typical loading in March at 12PM with 3 solar customers

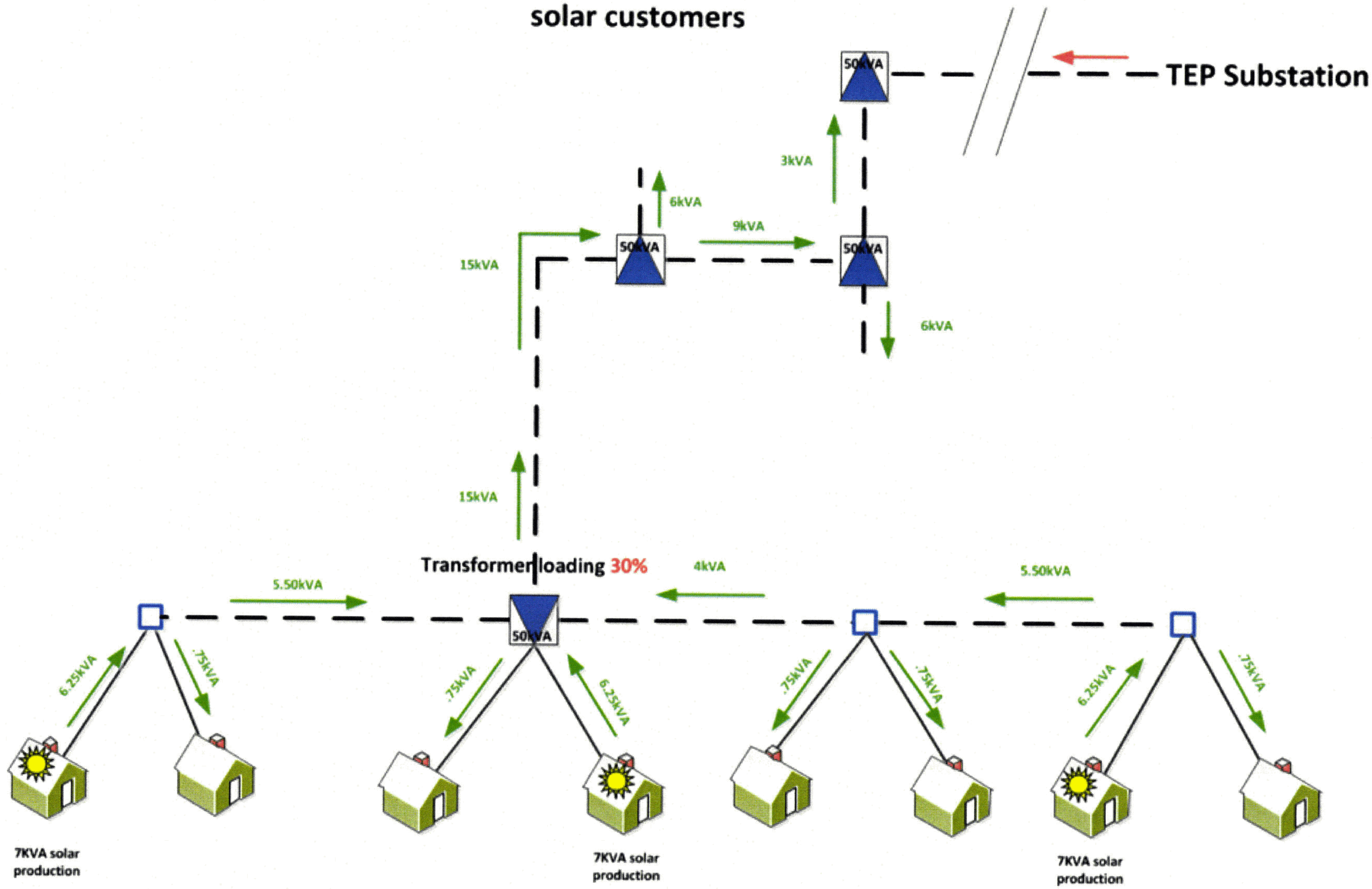
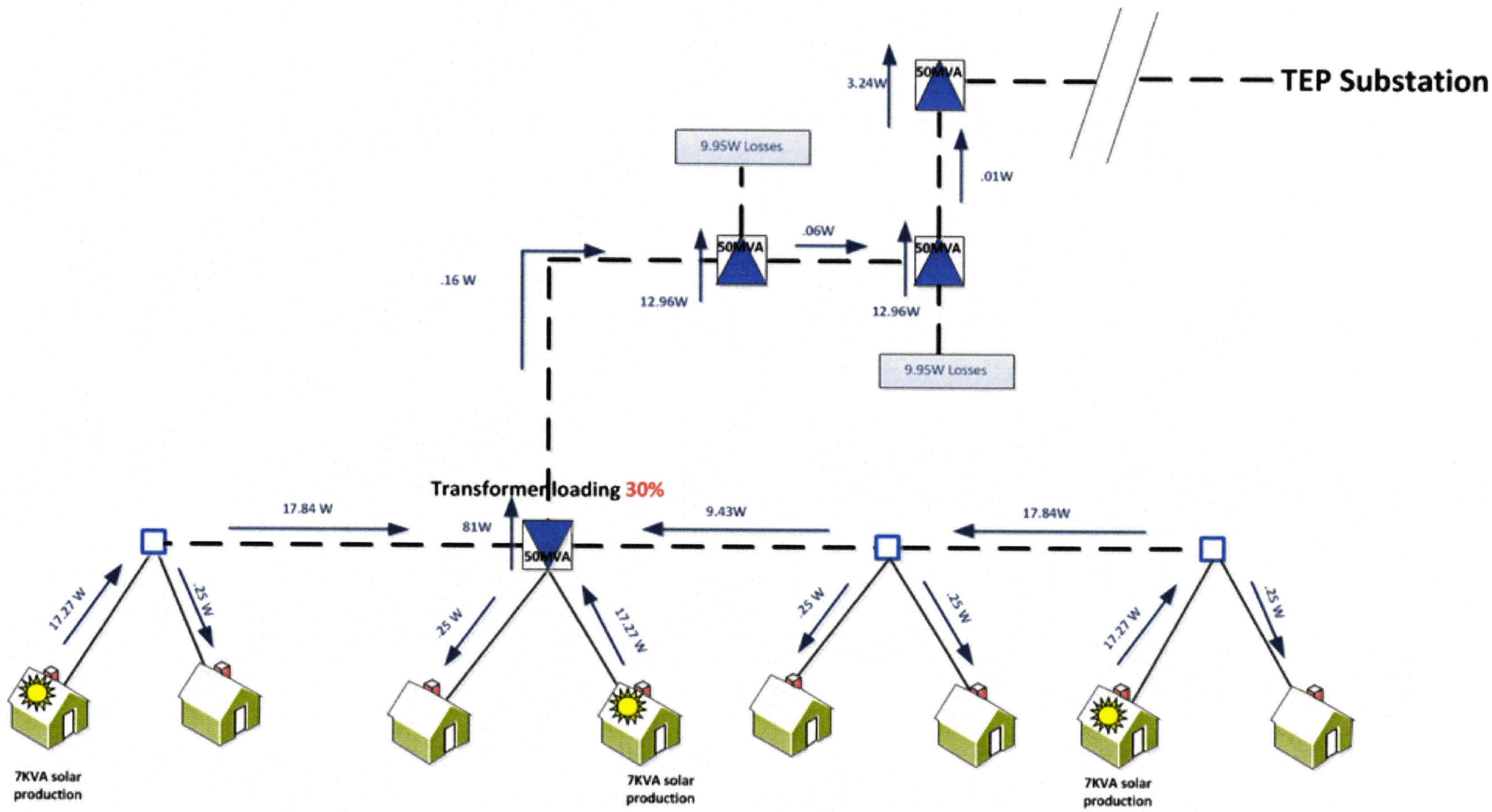



Exhibit 6

## Solar Generation losses associated with 3 houses producing 7kVA at daytime minimum




## Total Solar Generation Losses = 228.45W

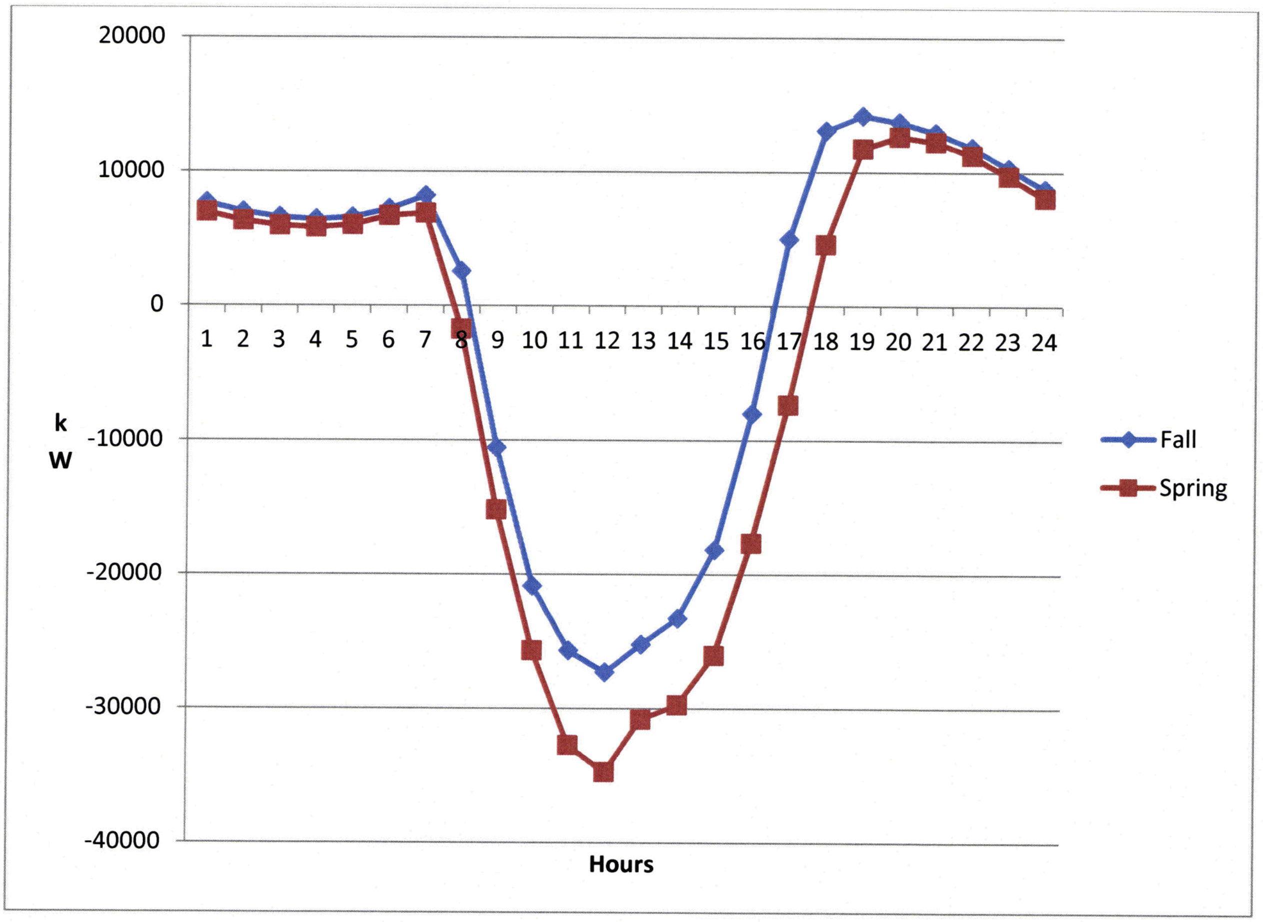
Exhibit 7

| Solar PV Systems Per Transformer | Transformer Loading % | Losses (W) |
|---|---|---|
| 1 | 2 | 44.2 |
| 2 | 16 | 107.95 |
| 3 | 30 | 228.45 |

Table 1

# Exhibit HEO - 4

## Fall and Spring Net DG Customer Load Shapes



# Exhibit HEO - 5

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

TUCSON I
TEST PE
2016 Ra

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| I. ELECTRIC PLANT IN SERVICE | | | | | | | | | |
| A. INTANGIBLE PLANT | | | | | | | | | |
| Intangible Plant | 301-303 | 160,246,771 | 92,907,042 | 2,034,604 | 33,006,195 | 16,114,538 | 11,847,834 | 3,184,513 | 1,152,044 |
| Subtotal - INTANGIBLE PLANT | 301-303 | 160,246,771 | 92,907,042 | 2,034,604 | 33,006,195 | 16,114,538 | 11,847,834 | 3,184,513 | 1,152,044 |
| B. PRODUCTION PLANT | | | | | | | | | |
| STEAM PRODUCTION PLANT | | | | | | | | | |
| Land & Land Rights | 310 | 6,057,619 | 3,120,083 | 68,926 | 1,391,363 | 740,686 | 532,776 | 203,784 | 0 |
| StructuresImprovements | 311 | 195,860,951 | 100,881,608 | 2,228,598 | 44,986,944 | 23,948,596 | 17,226,257 | 6,588,948 | 0 |
| Boiler Plant Equipment | 312 | 1,000,007,373 | 515,071,285 | 11,378,554 | 229,689,865 | 122,274,363 | 87,952,109 | 33,641,196 | 0 |
| Reactor Plant Equipment | 322 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Turbogenerator Units | 314 | 294,774,517 | 151,828,770 | 3,354,083 | 67,706,220 | 36,043,100 | 25,925,849 | 9,916,494 | 0 |
| Accessory Electric Equipment | 315 | 134,465,967 | 69,259,048 | 1,530,017 | 30,885,242 | 16,441,619 | 11,826,478 | 4,523,563 | 0 |
| Miscellaneous Power Plant Equipment | 316 | 25,580,106 | 13,175,481 | 291,062 | 5,875,448 | 3,127,768 | 2,249,808 | 860,539 | 0 |
| Sundt/SPV/SGS1 Acquisition Adjustment | 114 | -31,854,390 | -16,407,161 | -362,454 | -7,316,577 | -3,894,947 | -2,801,640 | -1,071,612 | 0 |
| Electric Plant Purchased or Sold | 102 | 15,029 | 7,741 | 171 | 3,452 | 1,838 | 1,322 | 506 | 0 |
| OTHER PRODUCTION PLANT | | | | | | | | | |
| Land and Land Rights | 340 | 1,873,363 | 964,909 | 21,316 | 430,289 | 229,063 | 164,765 | 63,022 | 0 |
| Structures and Improvements | 341 | 21,065,337 | 10,850,070 | 239,691 | 4,838,459 | 2,575,732 | 1,852,727 | 708,658 | 0 |
| Boiler Plant Equipment | 342 | 17,936,074 | 9,238,289 | 204,085 | 4,119,704 | 2,193,106 | 1,577,504 | 603,387 | 0 |
| Reactor Plant Equipment | 343 | 181,875,041 | 93,677,920 | 2,069,460 | 41,774,546 | 22,238,491 | 15,996,175 | 6,118,449 | 0 |
| Engines and Generators | 344 | 244,472,493 | 125,919,833 | 2,781,723 | 56,152,440 | 29,892,498 | 21,501,713 | 8,224,286 | 0 |
| Turbogenerator Units | 345 | 12,398,839 | 6,386,239 | 141,080 | 2,847,867 | 1,516,049 | 1,090,496 | 417,109 | 0 |
| Accessory Electric Equipment | 346&347 | 13,743,196 | 7,078,673 | 156,377 | 3,156,650 | 1,680,428 | 1,208,734 | 462,334 | 0 |
| Misc. Power Plant Equipment | 114 | -37,278,677 | -19,201,034 | -424,174 | -8,562,471 | -4,558,193 | -3,278,714 | -1,254,090 | 0 |
| Subtotal - PRODUCTION PLANT | 304-346 | 2,080,992,837 | 1,071,851,753 | 23,678,515 | 477,979,440 | 254,450,197 | 183,026,359 | 70,006,572 | 0 |
| C. TRANSMISSION PLANT | | | | | | | | | |
| Land and Land Rights | 350 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structures and Improvements | 352 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Station Equipment | 353 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Towers and Fixtures | 354 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Poles and Fixtures | 355 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Overhead Conductors and Devices | 356 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Underground Conduit | 357 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Underground Conductors and Devices | 358 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Roads and Trails | 359 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - TRANSMISSION PLANT | 350-359 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Base Electric COSS**
**Allocation Phase**



| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| D. DISTRIBUTION PLANT | | | | | | | | | |
| Land and Land Rights | 360 | 11,605,107 | 6,206,427 | 103,921 | 2,761,319 | 1,415,243 | 1,109,368 | 0 | 8,830 |
| Structures and Improvements | 361 | 11,835,474 | 6,329,627 | 105,984 | 2,816,132 | 1,443,336 | 1,131,389 | 0 | 9,005 |
| Station Equipment | 362 | 161,677,439 | 86,465,310 | 1,447,786 | 38,469,527 | 19,716,560 | 15,455,241 | 0 | 123,017 |
| Compressor Station Equipment | 363 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Poles, Towers and Fixtures | 364 | 233,534,842 | 171,804,410 | 4,004,873 | 33,123,849 | 10,603,690 | 8,123,174 | 0 | 5,874,847 |
| Overhead Conductors and Devices | 365 | 183,006,168 | 109,574,631 | 2,116,176 | 37,945,458 | 17,858,051 | 13,951,321 | 0 | 1,560,531 |
| Underground Conduit | 366 | 61,247,158 | 52,086,600 | 1,337,060 | 5,324,180 | 102,415 | 2,495 | 0 | 2,394,407 |
| Underground Conductors and Devices | 367 | 304,496,075 | 202,095,652 | 4,327,879 | 53,672,692 | 22,175,997 | 17,225,188 | 0 | 4,998,668 |
| Line Transformers | 368 | 281,381,714 | 174,300,686 | 3,453,765 | 56,998,305 | 26,189,309 | 20,439,489 | 160 | 0 |
| Services | 369 | 134,848,680 | 114,679,759 | 2,943,823 | 11,722,318 | 225,488 | 5,494 | 0 | 5,271,798 |
| Meters | 370 | 46,154,903 | 33,856,083 | 869,084 | 10,524,428 | 0 | 893,157 | 12,152 | 0 |
| Installed on Cust Premise PR_L | 371 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Property on Customers Premise | 372 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Street Lighting and Signals | 373 | 11,995,791 | 0 | 0 | 0 | 0 | 0 | 0 | 11,995,791 |
| Subtotal - DISTRIBUTION PLANT | 374-387 | 1,441,783,351 | 957,399,184 | 20,710,351 | 253,358,208 | 99,730,087 | 78,336,315 | 12,311 | 32,236,894 |
| E. GENERAL PLANT | | | | | | | | | |
| General Plant | 389-399 | 314,077,737 | 180,971,605 | 3,958,862 | 65,181,072 | 31,577,691 | 23,298,616 | 6,242,578 | 2,847,314 |
| Subtotal - GENERAL PLANT | 389-399 | 314,077,737 | 180,971,605 | 3,958,862 | 65,181,072 | 31,577,691 | 23,298,616 | 6,242,578 | 2,847,314 |
| TOTAL PLANT IN SERVICE | 101 | 3,997,100,696 | 2,303,129,584 | 50,382,332 | 829,524,916 | 401,872,513 | 296,509,125 | 79,445,974 | 36,236,252 |
| ADDITIONS TO UTILITY PLANT | | | | | | | | | |
| Energy Conservation Programs | 182.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Property Held for Future Use | 105 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction Work in Progress | 107 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear Plant Costs - Calvert Cliffs | 182.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Additions to Utility Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL UTILITY PLANT | | 3,997,100,696 | 2,303,129,584 | 50,382,332 | 829,524,916 | 401,872,513 | 296,509,125 | 79,445,974 | 36,236,252 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Base Electric COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 Ra**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| II. DEPRECIATION RESERVE | | | | | | | | | |
| Intangible | 301-303 | -119,977,698 | -69,131,154 | -1,512,285 | -24,899,170 | -12,062,678 | -8,900,072 | -2,384,665 | -1,087,674 |
| Production | 304-359 | -796,297,495 | -410,146,950 | -9,060,647 | -182,900,116 | -97,366,051 | -70,035,528 | -26,788,203 | 0 |
| Transmission | 350-359 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Land and Land Rights | 360 | -3,862,742 | -2,065,799 | -34,590 | -919,101 | -471,061 | -369,251 | 0 | -2,939 |
| Structures and Improvements | 361 | -3,279,743 | -1,754,011 | -29,369 | -780,382 | -399,965 | -313,521 | 0 | -2,495 |
| Station Equipment | 362 | -54,387,561 | -29,086,540 | -487,029 | -12,940,975 | -6,632,562 | -5,199,073 | 0 | -41,382 |
| Compressor Station Equipment | 363 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Poles, Towers and Fixtures | 364 | -87,160,606 | -64,121,380 | -1,494,711 | -12,362,587 | -3,957,542 | -3,031,756 | 0 | -2,192,629 |
| Overhead Conductors and Devices | 365 | -71,943,372 | -43,580,256 | -844,856 | -14,968,663 | -7,021,347 | -5,484,567 | -34 | -43,650 |
| Underground Conduit | 366 | -27,348,184 | -23,257,796 | -597,026 | -2,377,362 | -45,730 | -1,114 | 0 | -1,069,155 |
| Underground Conductors and Devices | 367 | -141,085,166 | -93,638,969 | -2,005,279 | -24,868,697 | -10,275,023 | -7,981,116 | 0 | -2,316,082 |
| Line Transformers | 368 | -135,774,711 | -82,973,907 | -1,637,504 | -27,387,686 | -12,634,865 | -9,862,583 | 0 | -1,278,167 |
| Services | 369 | -52,591,903 | -44,725,886 | -1,148,111 | -4,571,784 | -87,942 | -2,143 | 0 | -2,056,037 |
| Meters | 370 | 4,020,491 | 2,949,157 | 75,705 | 916,769 | 0 | 77,802 | 1,059 | 0 |
| Street Lighting and Signals | 373 | -5,781,491 | 0 | 0 | 0 | 0 | 0 | 0 | -5,781,491 |
| General | 389-398 | -86,548,234 | -49,869,096 | -1,090,916 | -17,961,498 | -8,701,646 | -6,420,239 | -1,720,224 | -784,615 |
| Subtotal-DEPRECIATION RESERVE | | -1,582,018,414 | -911,402,588 | -19,866,619 | -326,021,251 | -159,656,413 | -117,523,160 | -30,892,067 | -16,656,315 |
| Dep. Res.- adjust for 13 month avg. | 108.9 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL RESERVE FOR DEPRECIATION | 108 | -1,582,018,414 | -911,402,588 | -19,866,619 | -326,021,251 | -159,656,413 | -117,523,160 | -30,892,067 | -16,656,315 |
| III. OTHER RATE BASE ITEMS | | | | | | | | | |
| Cash Working Capital | n/a | -10,528,676 | -6,066,623 | -132,711 | -2,185,033 | -1,058,564 | -781,028 | -209,267 | -95,449 |
| Fuel Inventory | 151, 152 | 25,107,584 | 12,932,100 | 285,686 | 5,766,915 | 3,069,991 | 2,208,249 | 844,643 | 0 |
| Materials & Supplies | 154, 163 | 77,125,097 | 44,439,484 | 972,140 | 16,005,899 | 7,754,235 | 5,721,221 | 1,532,931 | 699,188 |
| Prepayments | 165 | 9,439,165 | 4,553,012 | 94,465 | 1,978,941 | 1,259,751 | 1,086,594 | 419,119 | 47,283 |
| Customer Advances for Construction | 252 | -11,046,099 | -5,908,604 | -98,934 | -2,628,814 | -1,347,330 | -1,056,133 | 0 | -6,284 |
| Customer Deposits | 235 | -19,400,461 | -10,377,386 | -173,760 | -4,617,032 | -2,366,340 | -1,854,906 | 0 | -11,036 |
| Deferred Credits - Asset Retirement - tax cr | 230&253 | -2,630,793 | -1,515,863 | -33,160 | -545,973 | -264,503 | -195,155 | -52,289 | -23,850 |
| Plant Held for Future Use - Transmission Pl | 105 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Regulatory Assets | 182 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Regulatory Liabilities | 254 | 25,112,104 | 14,469,595 | 316,531 | 5,211,556 | 2,524,796 | 1,862,842 | 499,126 | 227,657 |
| ADIT | 190 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ADIT - Other Property | 283 | -403,582,512 | -232,544,260 | -5,087,044 | -83,756,146 | -40,576,591 | -29,938,174 | -8,021,566 | -3,658,731 |
| Total - OTHER RATE BASE ITEMS | 131-283 | -310,404,592 | -180,018,544 | -3,856,788 | -64,769,687 | -31,004,554 | -22,946,491 | -4,987,304 | -2,821,223 |
| TOTAL RATE BASE | | 2,104,677,691 | 1,211,708,451 | 26,658,925 | 438,733,978 | 211,211,546 | 156,039,474 | 43,566,603 | 16,758,714 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Base Electric COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 Ra**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| I. OPERATING AND MAINTENANCE EXPE | | | | | | | | | |
| A. PRODUCTION EXPENSES | | | | | | | | | |
| Operation Supervision & Engineering | 500 | 9,802,746 | 5,049,076 | 111,540 | 2,251,575 | 1,198,616 | 862,166 | 329,774 | 0 |
| PPFAC - FUEL | 501 | 303,925,690 | 121,068,180 | 2,478,666 | 62,245,531 | 50,002,169 | 47,317,185 | 19,496,303 | 1,317,657 |
| Steam Expenses | 502 | 21,363,731 | 11,003,763 | 243,087 | 4,906,996 | 2,612,217 | 1,878,971 | 718,696 | 0 |
| Electric Expenses | 505 | 2,800,879 | 1,442,642 | 31,870 | 643,329 | 342,473 | 246,341 | 94,224 | 0 |
| Miscellaneous Steam Power Expenses | 506 | 4,495,150 | 2,315,306 | 51,148 | 1,032,483 | 549,638 | 395,355 | 151,221 | 0 |
| Rents | 507 | 14,157,699 | 7,292,171 | 161,093 | 3,251,856 | 1,731,111 | 1,245,190 | 476,278 | 0 |
| Maintenance Supervision & Engineering | 510 | 4,146,264 | 2,135,606 | 47,178 | 952,348 | 506,978 | 364,670 | 139,484 | 0 |
| Maintenance of Structures | 511 | 3,573,450 | 1,840,568 | 40,660 | 820,779 | 436,938 | 314,290 | 120,214 | 0 |
| Maintenance of Boiler Plant | 512 | 30,090,681 | 15,498,732 | 342,386 | 6,911,474 | 3,679,292 | 2,646,519 | 1,012,279 | 0 |
| Maintenance of Electric Plant | 513 | 5,140,971 | 2,647,947 | 58,496 | 1,180,820 | 628,604 | 452,156 | 172,947 | 0 |
| Maintenance Miscellaneous Steam Plant | 514 | 6,697,663 | 3,449,749 | 76,209 | 1,538,374 | 818,946 | 589,069 | 225,316 | 0 |
| FAS 143 Accretion Expense | 411 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loss from Disposition of Utility Plant | 412 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Other Production | 500-554 | 406,194,926 | 173,743,738 | 3,642,333 | 85,735,565 | 62,506,983 | 56,311,913 | 22,936,737 | 1,317,657 |
| Operation Supervision & Engineering | 546 | 7,586,523 | 3,907,572 | 86,323 | 1,742,535 | 927,630 | 667,246 | 255,218 | 0 |
| PPFAC - Fuel | 547 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Generation Exp & Misc Other Power Gener. | 548 & 549 | 1,498,181 | 771,664 | 17,047 | 344,114 | 183,188 | 131,767 | 50,400 | 0 |
| Rents | 550 | 10,337 | 5,324 | 118 | 2,374 | 1,264 | 909 | 348 | 0 |
| Maintenance Supervision & Engineering | 551 | 2,193 | 1,129 | 25 | 504 | 268 | 193 | 74 | 0 |
| Maintenance Structures, Generating, Other | 552-554 | 5,740,669 | 2,956,832 | 65,320 | 1,318,564 | 701,932 | 504,900 | 193,122 | 0 |
| Other Expenses | 557 | 645,356 | 332,402 | 7,343 | 148,231 | 78,910 | 56,760 | 21,710 | 0 |
| Subtotal | 556-557 | 15,483,258 | 7,974,923 | 176,176 | 3,556,321 | 1,893,192 | 1,361,775 | 520,871 | 0 |
| TOTAL PRODUCTION EXPENSE | 500-557 | 421,678,184 | 181,718,661 | 3,818,509 | 89,291,886 | 64,400,174 | 57,673,688 | 23,457,608 | 1,317,657 |

**TUCSON ELECTRIC POWER COMPANY**
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**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 Ra**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| B. TRANSMISSION EXPENSE | | | | | | | | | |
| Supervision and Engineering | 560 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Load Dispatching | 561 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Station Expenses | 562 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Overhead Line Expenses | 563 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Underground Lines Expenses | 564 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transmission by Others | 565 | 95,464,952 | 49,418,631 | 827,472 | 21,986,984 | 11,268,859 | 8,833,333 | 3,059,365 | 70,310 |
| Miscellaneous Expenses | 566 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rents | 567 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Supervision and Engineering | 568 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Structures | 569 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Station Equipment | 570 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Overhead Lines | 571 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Underground Lines | 572 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Misc Maintenance - Credits | 573 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL TRANSMISSION EXPENSES | 560-573 | 95,464,952 | 49,418,631 | 827,472 | 21,986,984 | 11,268,859 | 8,833,333 | 3,059,365 | 70,310 |
| C. DISTRIBUTION EXPENSE | | | | | | | | | |
| Operation Supervision & Engineering | 580 | 719,344 | 461,036 | 9,765 | 142,377 | 53,179 | 43,452 | 27 | 9,508 |
| Load Dispatching | 581 | 701,361 | 375,161 | 6,282 | 166,914 | 85,547 | 67,058 | 0 | 399 |
| Station Expenses | 582 | 263,040 | 140,701 | 2,356 | 62,600 | 32,084 | 25,150 | 0 | 150 |
| Overhead Line Expenses | 583 | 831,367 | 497,780 | 9,613 | 172,380 | 81,126 | 63,379 | 0 | 7,089 |
| Underground Line Expenses | 584 | 247,581 | 164,321 | 3,519 | 43,640 | 18,031 | 14,006 | 0 | 4,064 |
| Street Light and Signal Systems | 585 | 219,325 | 0 | 0 | 0 | 0 | 0 | 0 | 219,325 |
| Meter Expenses | 586 | 2,764,693 | 2,027,990 | 52,058 | 630,416 | 0 | 53,500 | 728 | 0 |
| Customer Installation Expenses | 587 | 59,339 | 43,527 | 1,117 | 13,531 | 0 | 1,148 | 16 | 0 |
| Misc. Distribution Expenses | 588 | 11,306,668 | 7,512,552 | 162,529 | 1,984,910 | 782,122 | 614,015 | 92 | 250,448 |
| Rents | 589 | 834,309 | 554,345 | 11,993 | 146,465 | 57,712 | 45,308 | 7 | 18,480 |
| Maint Supervision & Engineering | 590 | 1,054,638 | 675,931 | 14,317 | 208,741 | 77,966 | 63,705 | 40 | 13,939 |
| Maint of Structures | 591 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Station Equipment | 592 | 1,385,470 | 740,951 | 12,407 | 329,659 | 168,958 | 132,441 | 0 | 1,054 |
| Maintenance of Overhead Lines | 593 | 2,298,053 | 1,375,955 | 26,573 | 476,490 | 224,248 | 175,190 | 0 | 19,596 |
| Maintenance of Underground Lines | 594 | 132,130 | 87,695 | 1,878 | 23,290 | 9,623 | 7,475 | 0 | 2,169 |
| Maintenance of Line Transformers | 595 | 155,703 | 96,450 | 1,911 | 31,540 | 14,492 | 11,310 | 0 | 0 |
| Maintenance of Street Lights | 596 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Meters | 597 | 127,603 | 93,601 | 2,403 | 29,097 | 0 | 2,469 | 34 | 0 |
| Maintenance of Misc. Plant | 598 | 576,162 | 382,822 | 8,282 | 101,146 | 39,855 | 31,289 | 5 | 12,762 |
| Regulatory Asset Amortization | 407 | 408,531 | 271,442 | 5,872 | 71,718 | 28,260 | 22,186 | 3 | 9,049 |
| Subtotal - DISTRIBUTION EXPENSES | 580-599 | 24,085,317 | 15,502,260 | 332,876 | 4,634,914 | 1,673,202 | 1,373,080 | 951 | 568,033 |
| Total - OPER. AND MAINT. EXPENSE | 500-599 | 541,228,453 | 246,639,552 | 4,978,856 | 115,913,784 | 77,342,236 | 67,880,101 | 26,517,924 | 1,956,000 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Base Electric COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 Ra**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| D. CUSTOMER ACCOUNTS AND SERVIC | | | | | | | | | |
| Supervision | 901 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Meter Reading Expenses | 902 | 1,538,844 | 1,358,784 | 34,880 | 138,892 | 2,672 | 3,255 | 362 | 0 |
| Customer Records & Collection Expense | 903 | 18,299,064 | 15,527,614 | 398,593 | 1,587,199 | 30,531 | 37,194 | 4,133 | 713,800 |
| Uncollectible Accounts | 904 | 1,723,975 | 900,575 | 18,438 | 518,272 | 286,690 | 0 | 0 | 0 |
| Misc Customer Accounts Expenses | 905 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Customer Accounts Expense | 901-905 | 21,561,883 | 17,786,974 | 451,911 | 2,244,363 | 319,893 | 40,448 | 4,494 | 713,800 |
| Customer Assistance Exp Electric | (907, 908) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Supervision | 909 | 202,797 | 168,941 | 4,337 | 17,269 | 332 | 405 | 3,747 | 7,766 |
| Customer Assistance Expenses | 910 | 109,873 | 93,439 | 2,399 | 9,551 | 184 | 4 | 0 | 4,295 |
| Information, Instructional Advertising | 911 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Misc Customer Serv & Inform Expen | 912 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rents | 913 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Customer Service & Info. | 909-913 | 312,669 | 262,380 | 6,735 | 26,820 | 516 | 409 | 3,747 | 12,062 |
| Supervision | 915 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demonstrating & Selling Expenses | 916 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Advertising Expenses | 917 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Miscellaneous Sales Expenses | 918 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Sales Expense | 915-919 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total - CUST ACCTS, SERVS, & SALES E | 901-919 | 21,874,552 | 18,049,354 | 458,646 | 2,271,183 | 320,409 | 40,858 | 8,241 | 725,862 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Base Electric COSS**
**Allocation Phase**



| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| E. ADMINISTRATIVE AND GENERAL | | | | | | | | | |
| LABOR RELATED EXPENSES | | | | | | | | | |
| Administrative & General Salaries | 920 | 29,996,909 | 17,207,683 | 378,631 | 6,238,598 | 3,008,207 | 2,225,437 | 737,737 | 200,614 |
| Office Supplies & Expenses | 921 | 11,749,828 | 6,740,272 | 148,310 | 2,443,667 | 1,178,319 | 871,707 | 288,973 | 78,581 |
| Admin Expenses Transferred-Credit | 922 | -9,762,376 | -5,600,173 | -123,224 | -2,030,327 | -979,009 | -724,260 | -240,094 | -65,289 |
| Outside Services Employed | 923 | 11,102,007 | 6,368,650 | 140,133 | 2,308,937 | 1,113,353 | 823,645 | 273,040 | 74,248 |
| Employee Pensions and Benefits | 926 | 21,312,336 | 12,225,791 | 269,011 | 4,432,427 | 2,137,284 | 1,581,138 | 524,151 | 142,533 |
| Subtotal - O & M Accounts 920-923,926 | 920-926 | 64,398,703 | 36,942,223 | 812,862 | 13,393,301 | 6,458,154 | 4,777,668 | 1,583,807 | 430,688 |
| PLANT RELATED EXPENSES | | | | | | | | | |
| Property Insurance | 924 | 2,403,431 | 1,384,857 | 30,295 | 498,788 | 241,643 | 178,289 | 47,770 | 21,789 |
| Injuries and Damages | 925 | 2,054,306 | 1,183,691 | 25,894 | 426,334 | 206,542 | 152,391 | 40,831 | 18,624 |
| Maintenance of General Plant (also acct 93 | 935 | 26,768 | 15,424 | 337 | 5,555 | 2,691 | 1,986 | 532 | 243 |
| Subtotal - O & M Accounts 924-925 | 924,925,935 | 4,484,505 | 2,583,972 | 56,526 | 930,677 | 450,877 | 332,665 | 89,134 | 40,655 |
| OTHER A&G EXPENSES | | | | | | | | | |
| Franchise Requirements | 927 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Regulatory Commission Expenses | 928 | 1,326,223 | 761,006 | 16,739 | 275,783 | 133,021 | 98,390 | 32,209 | 9,075 |
| Duplicate Charges-Credit | 929 | -375,164 | -215,275 | -4,735 | -78,014 | -37,629 | -27,833 | -9,111 | -2,567 |
| General Advertising Expenses | 930 | 5,093,710 | 2,922,845 | 64,289 | 1,059,216 | 510,902 | 377,894 | 123,709 | 34,854 |
| Miscellaneous General Expenses | 930 | 107,111 | 61,462 | 1,352 | 22,273 | 10,743 | 7,946 | 2,601 | 733 |
| Rents | 931 | 687,396 | 394,438 | 8,676 | 142,941 | 68,946 | 50,997 | 16,695 | 4,704 |
| Misc Expenses - Credit | 932 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal | 927-932 | 6,839,276 | 3,924,477 | 86,320 | 1,422,199 | 685,984 | 507,395 | 166,103 | 46,799 |
| TOTAL A&G EXPENSES | 920-932 | 75,722,484 | 43,450,672 | 955,708 | 15,746,177 | 7,595,014 | 5,617,728 | 1,839,044 | 518,141 |
| TOTAL OPERATING EXPENSES | | 638,825,490 | 308,139,578 | 6,393,210 | 133,931,144 | 85,257,659 | 73,538,686 | 28,365,210 | 3,200,003 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Base Electric COSS**
**Allocation Phase**



| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| II. DEPRECIATION EXPENSE | | | | | | | | | |
| Intangible | 301-303 | 13,277,153 | 7,650,296 | 167,355 | 2,755,430 | 1,334,898 | 984,913 | 263,895 | 120,366 |
| Production - Steam | 500-511 | 60,024,743 | 30,459,942 | 662,293 | 13,630,703 | 7,517,151 | 5,585,177 | 2,166,051 | 3,426 |
| Production - Other | 546-557 | 12,557,762 | 6,468,095 | 142,888 | 2,884,369 | 1,535,481 | 1,104,474 | 422,455 | 0 |
| Transmission | 565 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Land & Rights | 360 | 86,658 | 46,345 | 776 | 20,619 | 10,568 | 8,284 | 0 | 66 |
| Structures & Improvements | 361 | 185,998 | 99,472 | 1,666 | 44,256 | 22,682 | 17,780 | 0 | 142 |
| Station Equipment | 362 | 2,445,508 | 1,307,861 | 21,899 | 581,884 | 298,230 | 233,774 | 0 | 1,861 |
| Poles, Towers, & Fixtures | 364 | 3,451,385 | 2,539,078 | 59,188 | 489,534 | 156,711 | 120,051 | 0 | 86,824 |
| Overhead Conductors & Devices | 365 | 2,779,481 | 1,683,692 | 32,640 | 578,304 | 271,265 | 211,892 | 1 | 1,686 |
| Underground Conduit | 366 | 750,665 | 638,390 | 16,387 | 65,255 | 1,255 | 31 | 0 | 29,347 |
| Underground Conductors & Devices | 367 | 4,999,675 | 3,318,311 | 71,062 | 881,279 | 364,119 | 282,829 | 0 | 82,076 |
| Line Transformers | 368 | 4,903,883 | 2,996,835 | 59,143 | 989,183 | 456,343 | 356,215 | 0 | 46,165 |
| Services | 369 | 1,916,596 | 1,629,936 | 41,840 | 166,609 | 3,205 | 78 | 0 | 74,928 |
| Meters | 370 | 2,037,023 | 1,494,221 | 38,357 | 464,490 | 0 | 39,419 | 536 | 0 |
| Street Lighting & Signal Systems | 373 | 194,790 | 59,524 | 1,041 | 26,492 | 13,651 | 10,574 | 3,713 | 79,796 |
| Distribution Plant Net Salvage | 403 | 5,407,146 | 3,115,598 | 68,156 | 1,122,154 | 543,640 | 401,108 | 107,472 | 49,019 |
| General | EDST | 14,684,437 | 8,461,173 | 185,093 | 3,047,485 | 1,476,388 | 1,089,307 | 291,866 | 133,124 |
| TOTAL DEPRECIATION EXPENSES | | 129,702,903 | 71,968,769 | 1,569,783 | 27,748,046 | 14,005,587 | 10,445,904 | 3,255,991 | 708,823 |
| III. TAXES | | | | | | | | | |
| A. GENERAL TAXES | | | | | | | | | |
| Payroll Taxes | 408 | 5,290,439 | 3,074,000 | 69,587 | 1,084,749 | 518,177 | 379,593 | 124,806 | 39,526 |
| PropertyTaxes - Production | 408 | 14,193,015 | 7,310,360 | 161,495 | 3,259,968 | 1,735,429 | 1,248,296 | 477,466 | 0 |
| PropertyTaxes - Transmission | 408 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PropertyTaxes - Distribution | 408 | 18,111,409 | 12,033,863 | 260,345 | 3,179,496 | 1,252,830 | 983,551 | 148 | 401,176 |
| PropertyTaxes - General | 408 | 3,070,559 | 1,769,256 | 38,704 | 637,238 | 308,717 | 227,777 | 61,030 | 27,837 |
| Business Activity Tax - Generation | 408 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Business Activity Tax - Transmission | 408 | 69,718 | 36,091 | 604 | 16,057 | 8,230 | 6,451 | 2,234 | 51 |
| Subtotal - General Taxes | | 40,735,140 | 24,223,570 | 530,735 | 8,177,508 | 3,823,383 | 2,845,668 | 665,685 | 468,590 |
| B. FRANCHISE AND REVENUE TAXES | | | | | | | | | |
| Franchise Tax T&D | 408.11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PSC Assessment | 408.12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Franchise Tax Prod | 408 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Franchise | 408.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Retail Sales & Other | 408.14 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Franchise & Gross Receipts | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Income Taxes - Current | | 33,355,599 | 19,219,497 | 420,438 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| Subtotal - Federal Income Taxes | 409-411 | 33,355,599 | 19,219,497 | 420,438 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| TOTAL TAXES | | 74,090,738 | 43,443,068 | 951,173 | 15,099,851 | 7,176,988 | 5,320,021 | 1,328,658 | 770,980 |
| TOTAL EXPENSES | | 842,619,131 | 423,551,414 | 8,914,166 | 176,779,041 | 106,440,234 | 89,304,612 | 32,949,858 | 4,679,806 |

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

TUCSON I
TEST PE
2016 Ra

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| IV. OPERATING REVENUES | | | | | | | | | |
| Revenues | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Production Other Rev | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Payment Charges | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Reconnect Charges-Missouri | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ot Elec Rev-Off-Sys | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rent From Elec Property-Mo | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Miscellaneous Service Revenues Retail | 451 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scrap Sales Revenues | 456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Electric Revenues | 447.5, 456.1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Electric Revenues - Misc Transmissic | 456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Electric - Ancillary | 147.4, 449.1, 456. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Excess Fac Revenues | 450-456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Operating Revenues | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gains/Losses from Energy Purchases | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Allowance for Funds During Construction | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interest on Customer Deposits | | -31,250 | -22,929 | -589 | -7,128 | 0 | -605 | 0 | 0 |
| V. NET INCOME | | -842,650,381 | -423,574,343 | -8,914,754 | -176,786,168 | -106,440,234 | -89,305,217 | -32,949,858 | -4,679,806 |
| Rate of Return | | -40.04% | -34.96% | -33.44% | -40.29% | -50.40% | -57.23% | -75.63% | -27.92% |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Base Electric COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 Ra**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| SUMMARY REPORT | | | | | | | | | |
| OPERATING REVENUES | | | | | | | | | |
| Utility Sales Revenues | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interdepartmental Revenues | 448 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Operating Revenues | 450-456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Operating Revenues | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OPERATING EXPENSES | | | | | | | | | |
| Production | 500-555 | 421,678,184 | 181,718,661 | 3,818,509 | 89,291,886 | 64,400,174 | 57,673,688 | 23,457,608 | 1,317,657 |
| Transmission | 560-573 | 95,464,952 | 49,418,631 | 827,472 | 21,986,984 | 11,268,859 | 8,833,333 | 3,059,365 | 70,310 |
| Distribution | 580-599 | 24,085,317 | 15,502,260 | 332,876 | 4,634,914 | 1,673,202 | 1,373,080 | 951 | 568,033 |
| Customer Acctg & Service | 901-919 | 21,874,552 | 18,049,354 | 458,646 | 2,271,183 | 320,409 | 40,858 | 8,241 | 725,862 |
| Admin & General | 920-932 | 75,722,484 | 43,450,672 | 955,708 | 15,746,177 | 7,595,014 | 5,617,728 | 1,839,044 | 518,141 |
| Total Operating Expenses | | 638,825,490 | 308,139,578 | 6,393,210 | 133,931,144 | 85,257,659 | 73,538,686 | 28,365,210 | 3,200,003 |
| DEPRECIATION EXPENSES | 403 | 129,702,903 | 71,968,769 | 1,569,783 | 27,748,046 | 14,005,587 | 10,445,904 | 3,255,991 | 708,823 |
| TAXES OTHER THAN INCOME TAX | 408 | 40,735,140 | 24,223,570 | 530,735 | 8,177,508 | 3,823,383 | 2,845,668 | 665,685 | 468,590 |
| INCOME BEFORE INCOME TAXES | | -809,263,532 | -404,331,917 | -8,493,728 | -169,856,698 | -103,086,629 | -86,830,259 | -32,286,886 | -4,377,416 |
| INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Income Taxes - Current | | 33,355,599 | 19,219,497 | 420,438 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| Subtotal - Federal Income Taxes | 409-411 | 33,355,599 | 19,219,497 | 420,438 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| OPERATING INCOME | | -842,619,131 | -423,551,414 | -8,914,166 | -176,779,041 | -106,440,234 | -89,304,612 | -32,949,858 | -4,679,806 |
| Gains/Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Allowance for Funds During Construction | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interest on Customer Deposits | | -31,250 | -22,929 | -589 | -7,128 | 0 | -605 | 0 | 0 |
| NET INCOME | | -842,650,381 | -423,574,343 | -8,914,754 | -176,786,168 | -106,440,234 | -89,305,217 | -32,949,858 | -4,679,806 |
| RATE BASE | | 2,104,677,691 | 1,211,708,451 | 26,658,925 | 438,733,978 | 211,211,546 | 156,039,474 | 43,566,603 | 16,758,714 |
| RETURN ON RATE BASE | | -40.04% | -34.96% | -33.44% | -40.29% | -50.40% | -57.23% | -75.63% | -27.92% |
| Unitized Rate of Return | | 1.00 | 0.87 | 0.84 | 1.01 | 1.26 | 1.43 | 1.89 | 0.70 |

TUCSON I
TEST PE
2016 Ra

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Base Electric COSS**
**Allocation Phase**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| **REVENUE REQUIREMENTS** | | | | | | | | | |
| RATE OF RETURN | | 5.22% | 5.52% | 5.52% | 5.52% | 5.52% | 5.52% | 5.52% | 5.52% |
| Using Target for System | | | | | | | | | |
| RATE BASE | | 2,104,677,691 | 1,211,708,451 | 26,658,925 | 438,733,978 | 211,211,546 | 156,039,474 | 43,566,603 | 16,758,714 |
| OPERATING EXPENSES | | 638,825,490 | 308,139,578 | 6,393,210 | 133,931,144 | 85,257,659 | 73,538,686 | 28,365,210 | 3,200,003 |
| DEPRECIATION EXPENSE | | 129,702,903 | 71,968,769 | 1,569,783 | 27,748,046 | 14,005,587 | 10,445,904 | 3,255,991 | 708,823 |
| GENERAL TAXES | | 40,735,140 | 24,223,570 | 530,735 | 8,177,508 | 3,823,383 | 2,845,668 | 665,685 | 468,590 |
| Other costs (benefits), net of taxes | | 31,250 | 22,929 | 589 | 7,128 | 0 | 605 | 0 | 0 |
| Subtotal- Operating Costs to recover | | 809,294,783 | 404,354,846 | 8,494,316 | 169,863,826 | 103,086,629 | 86,830,864 | 32,286,886 | 4,377,416 |
| Target Return on Rate Base- After taxes | | 116,218,763 | 66,909,654 | 1,472,086 | 24,226,569 | 11,662,947 | 8,616,386 | 2,405,716 | 925,404 |
| Actual Historic FIT | | 33,355,599 | 19,219,497 | 420,438 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| Incremental Tax Due to Target ROR | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal- Rev Req before Uncollectible Adj. | | 958,869,144 | 490,483,998 | 10,386,841 | 201,012,738 | 118,103,181 | 97,921,603 | 35,355,574 | 5,605,210 |
| Proforma Incr for Uncollect. Calc | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ECCR & Prop Tax Surcharge | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL REVENUE REQUIREMENT | | 958,869,144 | 490,483,998 | 10,386,841 | 201,012,738 | 118,103,181 | 97,921,603 | 35,355,574 | 5,605,210 |

# Exhibit HEO - 6

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**



| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| I. ELECTRIC PLANT IN SERVICE | | | | | | | | | |
| A. INTANGIBLE PLANT | | | | | | | | | |
| Intangible Plant | 301-303 | 160,246,771 | 92,199,072 | 2,742,574 | 33,006,195 | 16,114,538 | 11,847,834 | 3,184,513 | 1,152,044 |
| Subtotal - INTANGIBLE PLANT | 301-303 | 160,246,771 | 92,199,072 | 2,742,574 | 33,006,195 | 16,114,538 | 11,847,834 | 3,184,513 | 1,152,044 |
| B. PRODUCTION PLANT | | | | | | | | | |
| STEAM PRODUCTION PLANT | | | | | | | | | |
| Land & Land Rights | 310 | 6,057,619 | 3,092,329 | 96,680 | 1,391,363 | 740,686 | 532,776 | 203,784 | 0 |
| StructuresImprovements | 311 | 195,860,951 | 99,984,267 | 3,125,940 | 44,986,944 | 23,948,596 | 17,226,257 | 6,588,948 | 0 |
| Boiler Plant Equipment | 312 | 1,000,007,373 | 510,489,728 | 15,960,112 | 229,689,865 | 122,274,363 | 87,952,109 | 33,641,196 | 0 |
| Reactor Plant Equipment | 322 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Turbogenerator Units | 314 | 294,774,517 | 150,478,254 | 4,704,599 | 67,706,220 | 36,043,100 | 25,925,849 | 9,916,494 | 0 |
| Accessory Electric Equipment | 315 | 134,465,967 | 68,642,989 | 2,146,076 | 30,885,242 | 16,441,619 | 11,826,478 | 4,523,563 | 0 |
| Miscellaneous Power Plant Equipment | 316 | 25,580,106 | 13,058,285 | 408,258 | 5,875,448 | 3,127,768 | 2,249,808 | 860,539 | 0 |
| Sundt/SPV/SGS1 Acquisition Adjustment | 114 | -31,854,390 | -16,261,219 | -508,396 | -7,316,577 | -3,894,947 | -2,801,640 | -1,071,612 | 0 |
| Electric Plant Purchased or Sold | 102 | 15,029 | 7,672 | 240 | 3,452 | 1,838 | 1,322 | 506 | 0 |
| OTHER PRODUCTION PLANT | | | | | | | | | |
| Land and Land Rights | 340 | 1,873,363 | 956,326 | 29,899 | 430,289 | 229,063 | 164,765 | 63,022 | 0 |
| Structures and Improvements | 341 | 21,065,337 | 10,753,559 | 336,203 | 4,838,459 | 2,575,732 | 1,852,727 | 708,658 | 0 |
| Boiler Plant Equipment | 342 | 17,936,074 | 9,156,114 | 286,260 | 4,119,704 | 2,193,106 | 1,577,504 | 603,387 | 0 |
| Reactor Plant Equipment | 343 | 181,875,041 | 92,844,656 | 2,902,725 | 41,774,546 | 22,238,491 | 15,996,175 | 6,118,449 | 0 |
| Engines and Generators | 344 | 244,472,493 | 124,799,776 | 3,901,779 | 56,152,440 | 29,892,498 | 21,501,713 | 8,224,286 | 0 |
| Turbogenerator Units | 345 | 12,398,839 | 6,329,433 | 197,885 | 2,847,867 | 1,516,049 | 1,090,496 | 417,109 | 0 |
| Accessory Electric Equipment | 346&347 | 13,743,196 | 7,015,709 | 219,341 | 3,156,650 | 1,680,428 | 1,208,734 | 462,334 | 0 |
| Misc. Power Plant Equipment | 114 | -37,278,677 | -19,030,241 | -594,967 | -8,562,471 | -4,558,193 | -3,278,714 | -1,254,090 | 0 |
| Subtotal - PRODUCTION PLANT | 304-346 | 2,080,992,837 | 1,062,317,635 | 33,212,633 | 477,979,440 | 254,450,197 | 183,026,359 | 70,006,572 | 0 |
| C. TRANSMISSION PLANT | | | | | | | | | |
| Land and Land Rights | 350 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structures and Improvements | 352 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Station Equipment | 353 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Towers and Fixtures | 354 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Poles and Fixtures | 355 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Overhead Conductors and Devices | 356 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Underground Conduit | 357 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Underground Conductors and Devices | 358 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Roads and Trails | 359 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - TRANSMISSION PLANT | 350-359 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 Rat**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| D. DISTRIBUTION PLANT | | | | | | | | | |
| Land and Land Rights | 360 | 11,605,107 | 6,120,011 | 190,337 | 2,761,319 | 1,415,243 | 1,109,368 | 0 | 8,830 |
| Structures and Improvements | 361 | 11,835,474 | 6,241,496 | 194,115 | 2,816,132 | 1,443,336 | 1,131,389 | 0 | 9,005 |
| Station Equipment | 362 | 161,677,439 | 85,261,402 | 2,651,694 | 38,469,527 | 19,716,560 | 15,455,241 | 0 | 123,017 |
| Compressor Station Equipment | 363 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Poles, Towers and Fixtures | 364 | 233,534,842 | 171,172,115 | 4,637,167 | 33,123,849 | 10,603,690 | 8,123,174 | 0 | 5,874,847 |
| Overhead Conductors and Devices | 365 | 183,006,168 | 108,487,990 | 3,202,816 | 37,945,458 | 17,858,051 | 13,951,321 | 0 | 1,560,531 |
| Underground Conduit | 366 | 61,247,158 | 52,086,600 | 1,337,060 | 5,324,180 | 102,415 | 2,495 | 0 | 2,394,407 |
| Underground Conductors and Devices | 367 | 304,496,075 | 200,754,266 | 5,669,265 | 53,672,692 | 22,175,997 | 17,225,188 | 0 | 4,998,668 |
| Line Transformers | 368 | 281,381,714 | 172,708,746 | 5,045,704 | 56,998,305 | 26,189,309 | 20,439,489 | 160 | 0 |
| Services | 369 | 134,848,680 | 114,679,759 | 2,943,823 | 11,722,318 | 225,488 | 5,494 | 0 | 5,271,798 |
| Meters | 370 | 46,154,903 | 33,856,083 | 869,084 | 10,524,428 | 0 | 893,157 | 12,152 | 0 |
| Installed on Cust Premise PR_L | 371 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Property on Customers Premise | 372 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Street Lighting and Signals | 373 | 11,995,791 | 0 | 0 | 0 | 0 | 0 | 0 | 11,995,791 |
| Subtotal - DISTRIBUTION PLANT | 374-387 | 1,441,783,351 | 951,368,469 | 26,741,066 | 253,358,208 | 99,730,087 | 78,336,315 | 12,311 | 32,236,894 |
| E. GENERAL PLANT | | | | | | | | | |
| General Plant | 389-399 | 314,077,737 | 179,583,906 | 5,346,560 | 65,181,072 | 31,577,691 | 23,298,616 | 6,242,578 | 2,847,314 |
| Subtotal - GENERAL PLANT | 389-399 | 314,077,737 | 179,583,906 | 5,346,560 | 65,181,072 | 31,577,691 | 23,298,616 | 6,242,578 | 2,847,314 |
| TOTAL PLANT IN SERVICE | 101 | 3,997,100,696 | 2,285,469,083 | 68,042,833 | 829,524,916 | 401,872,513 | 296,509,125 | 79,445,974 | 36,236,252 |
| ADDITIONS TO UTILITY PLANT | | | | | | | | | |
| Enérgy Conservation Programs | 182.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Property Held for Future Use | 105 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction Work in Progress | 107 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear Plant Costs - Calvert Cliffs | 182.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Additions to Utility Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL UTILITY PLANT | | 3,997,100,696 | 2,285,469,083 | 68,042,833 | 829,524,916 | 401,872,513 | 296,509,125 | 79,445,974 | 36,236,252 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**



| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| II. DEPRECIATION RESERVE | | | | | | | | | |
| Intangible | 301-303 | -119,977,698 | -68,601,054 | -2,042,386 | -24,899,170 | -12,062,678 | -8,900,072 | -2,384,665 | -1,087,674 |
| Production | 304-359 | -796,297,495 | -406,498,695 | -12,708,903 | -182,900,116 | -97,366,051 | -70,035,528 | -26,788,203 | 0 |
| Transmission | 350-359 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Land and Land Rights | 360 | -3,862,742 | -2,037,036 | -63,353 | -919,101 | -471,061 | -369,251 | 0 | 0 |
| Structures and Improvements | 361 | -3,279,743 | -1,729,589 | -53,792 | -780,382 | -399,965 | -313,521 | 0 | -2,939 |
| Station Equipment | 362 | -54,387,561 | -28,681,551 | -892,018 | -12,940,975 | -6,632,562 | -5,199,073 | 0 | -2,495 |
| Compressor Station Equipment | 363 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | -41,382 |
| Poles, Towers and Fixtures | 364 | -87,160,606 | -63,885,393 | -1,730,698 | -12,362,587 | -3,957,542 | -3,031,756 | 0 | 0 |
| Overhead Conductors and Devices | 365 | -71,943,372 | -43,153,076 | -1,272,036 | -14,968,663 | -7,021,347 | -5,484,567 | 0 | -2,192,629 |
| Underground Conduit | 366 | -27,348,184 | -23,257,796 | -597,026 | -2,377,362 | -45,730 | -1,114 | -34 | -43,650 |
| Underground Conductors and Devices | 367 | -141,085,166 | -93,017,451 | -2,626,796 | -24,868,697 | -10,275,023 | -7,981,116 | 0 | -1,069,155 |
| Line Transformers | 368 | -135,774,711 | -82,205,750 | -2,405,660 | -27,387,686 | -12,634,865 | -9,862,583 | 0 | -2,316,082 |
| Services | 369 | -52,591,903 | -44,725,886 | -1,148,111 | -4,571,784 | -87,942 | -2,143 | 0 | -1,278,167 |
| Meters | 370 | 4,020,491 | 2,949,157 | 75,705 | 916,769 | 0 | 77,802 | 1,059 | -2,056,037 |
| Street Lighting and Signals | 373 | -5,781,491 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| General | 389-398 | -86,548,234 | -49,486,698 | -1,473,315 | -17,961,498 | -8,701,646 | -6,420,239 | -1,720,224 | -5,781,491 |
| Subtotal-DEPRECIATION RESERVE | | -1,582,018,414 | -904,330,818 | -26,938,389 | -326,021,251 | -159,656,413 | -117,523,160 | -30,892,067 | -784,615 |
| | | | | | | | | | -16,656,315 |
| Dep. Res.- adjust for 13 month avg. | 108.9 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL RESERVE FOR DEPRECIATION | 108 | -1,582,018,414 | -904,330,818 | -26,938,389 | -326,021,251 | -159,656,413 | -117,523,160 | -30,892,067 | -16,656,315 |
| III. OTHER RATE BASE ITEMS | | | | | | | | | |
| Cash Working Capital | n/a | -10,528,676 | -6,020,104 | -179,230 | -2,185,033 | -1,058,564 | -781,028 | -209,267 | -95,449 |
| Fuel Inventory | 151, 152 | 25,107,584 | 12,817,069 | 400,717 | 5,766,915 | 3,069,991 | 2,208,249 | 844,643 | 0 |
| Materials & Supplies | 154, 163 | 77,125,097 | 44,098,720 | 1,312,904 | 16,005,899 | 7,754,235 | 5,721,221 | 1,532,931 | 699,188 |
| Prepayments | 165 | 9,439,165 | 4,509,749 | 137,728 | 1,978,941 | 1,259,751 | 1,086,594 | 419,119 | 47,283 |
| Customer Advances for Construction | 252 | -11,046,099 | -5,826,335 | -181,203 | -2,628,814 | -1,347,330 | -1,056,133 | 0 | -6,284 |
| Customer Deposits | 235 | -19,400,461 | -10,232,895 | -318,251 | -4,617,032 | -2,366,340 | -1,854,906 | 0 | -11,036 |
| Deferred Credits - Asset Retirement - tax cr | 230&253 | -2,630,793 | -1,504,239 | -44,784 | -545,973 | -264,503 | -195,155 | -52,289 | -23,850 |
| Plant Held for Future Use - Transmission Pl | 105 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Regulatory Assets | 182 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Regulatory Liabilities | 254 | 25,112,104 | 14,358,642 | 427,485 | 5,211,556 | 2,524,796 | 1,862,842 | 499,126 | 227,657 |
| ADIT | 190 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ADIT - Other Property | 283 | -403,582,512 | -230,761,100 | -6,870,204 | -83,756,146 | -40,576,591 | -29,938,174 | -8,021,566 | -3,658,731 |
| Total - OTHER RATE BASE ITEMS | 131-283 | -310,404,592 | -178,560,493 | -5,314,839 | -64,769,687 | -31,004,554 | -22,946,491 | -4,987,304 | -2,821,223 |
| TOTAL RATE BASE | | 2,104,677,691 | 1,202,577,772 | 35,789,604 | 438,733,978 | 211,211,546 | 156,039,474 | 43,566,603 | 16,758,714 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 Rat**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| I. OPERATING AND MAINTENANCE EXPE | | | | | | | | | |
| A. PRODUCTION EXPENSES | | | | | | | | | |
| Operation Supervision & Engineering | 500 | 9,802,746 | 5,004,164 | 156,452 | 2,251,575 | 1,198,616 | 862,166 | 329,774 | 0 |
| PPFAC - FUEL | 501 | 303,925,690 | 119,807,088 | 3,739,757 | 62,245,531 | 50,002,169 | 47,317,185 | 19,496,303 | 1,317,657 |
| Steam Expenses | 502 | 21,363,731 | 10,905,885 | 340,965 | 4,906,996 | 2,612,217 | 1,878,971 | 718,696 | 0 |
| Electric Expenses | 505 | 2,800,879 | 1,429,810 | 44,702 | 643,329 | 342,473 | 246,341 | 94,224 | 0 |
| Miscellaneous Steam Power Expenses | 506 | 4,495,150 | 2,294,711 | 71,743 | 1,032,483 | 549,638 | 395,355 | 151,221 | 0 |
| Rents | 507 | 14,157,699 | 7,227,307 | 225,957 | 3,251,856 | 1,731,111 | 1,245,190 | 476,278 | 0 |
| Maintenance Supervision & Engineering | 510 | 4,146,264 | 2,116,610 | 66,174 | 952,348 | 506,978 | 364,670 | 139,484 | 0 |
| Maintenance of Structures | 511 | 3,573,450 | 1,824,196 | 57,032 | 820,779 | 436,938 | 314,290 | 120,214 | 0 |
| Maintenance of Boiler Plant | 512 | 30,090,681 | 15,360,870 | 480,247 | 6,911,474 | 3,679,292 | 2,646,519 | 1,012,279 | 0 |
| Maintenance of Electric Plant | 513 | 5,140,971 | 2,624,394 | 82,050 | 1,180,820 | 628,604 | 452,156 | 172,947 | 0 |
| Maintenance Miscellaneous Steam Plant | 514 | 6,697,663 | 3,419,063 | 106,895 | 1,538,374 | 818,946 | 589,069 | 225,316 | 0 |
| FAS 143 Accretion Expense | 411 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loss from Disposition of Utility Plant | 412 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Other Production | 500-554 | 406,194,926 | 172,014,097 | 5,371,974 | 85,735,565 | 62,506,983 | 56,311,913 | 22,936,737 | 1,317,657 |
| Operation Supervision & Engineering | 546 | 7,586,523 | 3,872,814 | 121,081 | 1,742,535 | 927,630 | 667,246 | 255,218 | 0 |
| PPFAC - Fuel | 547 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Generation Exp & Misc Other Power Gener | 548 & 549 | 1,498,181 | 764,800 | 23,911 | 344,114 | 183,188 | 131,767 | 50,400 | 0 |
| Rents | 550 | 10,337 | 5,277 | 165 | 2,374 | 1,264 | 909 | 348 | 0 |
| Maintenance Supervision & Engineering | 551 | 2,193 | 1,119 | 35 | 504 | 268 | 193 | 74 | 0 |
| Maintenance Structures, Generating, Other | 552-554 | 5,740,669 | 2,930,531 | 91,621 | 1,318,564 | 701,932 | 504,900 | 193,122 | 0 |
| Other Expenses | 557 | 645,356 | 329,445 | 10,300 | 148,231 | 78,910 | 56,760 | 21,710 | 0 |
| Subtotal | 556-557 | 15,483,258 | 7,903,986 | 247,113 | 3,556,321 | 1,893,192 | 1,361,775 | 520,871 | 0 |
| TOTAL PRODUCTION EXPENSE | 500-557 | 421,678,184 | 179,918,084 | 5,619,086 | 89,291,886 | 64,400,174 | 57,673,688 | 23,457,608 | 1,317,657 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 Rat**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| B. TRANSMISSION EXPENSE | | | | | | | | | |
| Supervision and Engineering | 560 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Load Dispatching | 561 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Station Expenses | 562 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Overhead Line Expenses | 563 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Underground Lines Expenses | 564 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transmission by Others | 565 | 95,464,952 | 48,730,546 | 1,515,557 | 21,986,984 | 11,268,859 | 8,833,333 | 3,059,365 | 70,310 |
| Miscellaneous Expenses | 566 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rents | 567 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Supervision and Engineering | 568 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Structures | 569 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Station Equipment | 570 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Overhead Lines | 571 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Underground Lines | 572 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Misc Maintenance - Credits | 573 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL TRANSMISSION EXPENSES | 560-573 | 95,464,952 | 48,730,546 | 1,515,557 | 21,986,984 | 11,268,859 | 8,833,333 | 3,059,365 | 70,310 |
| C. DISTRIBUTION EXPENSE | | | | | | | | | |
| Operation Supervision & Engineering | 580 | 719,344 | 457,808 | 12,994 | 142,377 | 53,179 | 43,452 | 27 | 9,508 |
| Load Dispatching | 581 | 701,361 | 369,937 | 11,505 | 166,914 | 85,547 | 67,058 | 0 | 399 |
| Station Expenses | 582 | 263,040 | 138,742 | 4,315 | 62,600 | 32,084 | 25,150 | 0 | 150 |
| Overhead Line Expenses | 583 | 831,367 | 492,843 | 14,550 | 172,380 | 81,126 | 63,379 | 0 | 7,089 |
| Underground Line Expenses | 584 | 247,581 | 163,230 | 4,610 | 43,640 | 18,031 | 14,006 | 0 | 4,064 |
| Street Light and Signal Systems | 585 | 219,325 | 0 | 0 | 0 | 0 | 0 | 0 | 219,325 |
| Meter Expenses | 586 | 2,764,693 | 2,027,990 | 52,058 | 630,416 | 0 | 53,500 | 728 | 0 |
| Customer Installation Expenses | 587 | 59,339 | 43,527 | 1,117 | 13,531 | 0 | 1,148 | 16 | 0 |
| Misc. Distribution Expenses | 588 | 11,306,668 | 7,465,258 | 209,822 | 1,984,910 | 782,122 | 614,015 | 92 | 250,448 |
| Rents | 589 | 834,309 | 550,855 | 15,483 | 146,465 | 57,712 | 45,308 | 7 | 18,480 |
| Maint Supervision & Engineering | 590 | 1,054,638 | 671,197 | 19,050 | 208,741 | 77,966 | 63,705 | 40 | 13,939 |
| Maint of Structures | 591 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Station Equipment | 592 | 1,385,470 | 730,634 | 22,723 | 329,659 | 168,958 | 132,441 | 0 | 1,054 |
| Maintenance of Overhead Lines | 593 | 2,298,053 | 1,362,310 | 40,219 | 476,490 | 224,248 | 175,190 | 0 | 19,596 |
| Maintenance of Underground Lines | 594 | 132,130 | 87,113 | 2,460 | 23,290 | 9,623 | 7,475 | 0 | 2,169 |
| Maintenance of Line Transformers | 595 | 155,703 | 95,569 | 2,792 | 31,540 | 14,492 | 11,310 | 0 | 0 |
| Maintenance of Street Lights | 596 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Meters | 597 | 127,603 | 93,601 | 2,403 | 29,097 | 0 | 2,469 | 34 | 0 |
| Maintenance of Misc. Plant | 598 | 576,162 | 380,412 | 10,692 | 101,146 | 39,855 | 31,289 | 5 | 12,762 |
| Regulatory Asset Amortization | 407 | 408,531 | 269,734 | 7,581 | 71,718 | 28,260 | 22,186 | 3 | 9,049 |
| Subtotal - DISTRIBUTION EXPENSES | 580-599 | 24,085,317 | 15,400,761 | 434,374 | 4,634,914 | 1,673,202 | 1,373,080 | 951 | 568,033 |
| Total - OPER. AND MAINT. EXPENSE | 500-599 | 541,228,453 | 244,049,391 | 7,569,018 | 115,913,784 | 77,342,236 | 67,880,101 | 26,517,924 | 1,956,000 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**



| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| D. CUSTOMER ACCOUNTS AND SERVIC | | | | | | | | | |
| Supervision | 901 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Meter Reading Expenses | 902 | 1,538,844 | 1,358,784 | 34,880 | 138,892 | 2,672 | 3,255 | 362 | 0 |
| Customer Records & Collection Expense | 903 | 18,299,064 | 15,527,614 | 398,593 | 1,587,199 | 30,531 | 37,194 | 4,133 | 713,800 |
| Uncollectible Accounts | 904 | 1,723,975 | 891,194 | 27,818 | 518,272 | 286,690 | 0 | 0 | 0 |
| Misc Customer Accounts Expenses | 905 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Customer Accounts Expense | 901-905 | 21,561,883 | 17,777,593 | 461,291 | 2,244,363 | 319,893 | 40,448 | 4,494 | 713,800 |
| Customer Assistance Exp Electric | (907, 908) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Supervision | 909 | 202,797 | 168,941 | 4,337 | 17,269 | 332 | 405 | 3,747 | 7,766 |
| Customer Assistance Expenses | 910 | 109,873 | 93,439 | 2,399 | 9,551 | 184 | 4 | 0 | 4,295 |
| Information, Instructional Advertising | 911 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Misc Customer Serv & Inform Expen | 912 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rents | 913 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Customer Service & Info. | 909-913 | 312,669 | 262,380 | 6,735 | 26,820 | 516 | 409 | 3,747 | 12,062 |
| Supervision | 915 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demonstrating & Selling Expenses | 916 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Advertising Expenses | 917 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Miscellaneous Sales Expenses | 918 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Sales Expense | 915-919 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total - CUST ACCTS, SERVS, & SALES E | 901-919 | 21,874,552 | 18,039,973 | 468,027 | 2,271,183 | 320,409 | 40,858 | 8,241 | 725,862 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**



| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| E. ADMINISTRATIVE AND GENERAL | | | | | | | | | |
| LABOR RELATED EXPENSES | | | | | | | | | |
| Administrative & General Salaries | 920 | 29,996,909 | 17,077,757 | 508,558 | 6,238,598 | 3,008,207 | 2,225,437 | 737,737 | 200,614 |
| Office Supplies & Expenses | 921 | 11,749,828 | 6,689,380 | 199,203 | 2,443,667 | 1,178,319 | 871,707 | 288,973 | 78,581 |
| Admin Expenses Transferred-Credit | 922 | -9,762,376 | -5,557,889 | -165,508 | -2,030,327 | -979,009 | -724,260 | -240,094 | -65,289 |
| Outside Services Employed | 923 | 11,102,007 | 6,320,564 | 188,220 | 2,308,937 | 1,113,353 | 823,645 | 273,040 | 74,248 |
| Employee Pensions and Benefits | 926 | 21,312,336 | 12,133,480 | 361,322 | 4,432,427 | 2,137,284 | 1,581,138 | 524,151 | 142,533 |
| Subtotal - O & M Accounts 920-923,926 | 920-926 | 64,398,703 | 36,663,291 | 1,091,794 | 13,393,301 | 6,458,154 | 4,777,668 | 1,583,807 | 430,688 |
| PLANT RELATED EXPENSES | | | | | | | | | |
| Property Insurance | 924 | 2,403,431 | 1,374,238 | 40,914 | 498,788 | 241,643 | 178,289 | 47,770 | 21,789 |
| Injuries and Damages | 925 | 2,054,306 | 1,174,615 | 34,971 | 426,334 | 206,542 | 152,391 | 40,831 | 18,624 |
| Maintenance of General Plant (also acct 93 | 935 | 26,768 | 15,305 | 456 | 5,555 | 2,691 | 1,986 | 532 | 243 |
| Subtotal - O & M Accounts 924-925 | 924,925,935 | 4,484,505 | 2,564,158 | 76,340 | 930,677 | 450,877 | 332,665 | 89,134 | 40,655 |
| OTHER A&G EXPENSES | | | | | | | | | |
| Franchise Requirements | 927 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Regulatory Commission Expenses | 928 | 1,326,223 | 755,255 | 22,490 | 275,783 | 133,021 | 98,390 | 32,209 | 9,075 |
| Duplicate Charges-Credit | 929 | -375,164 | -213,648 | -6,362 | -78,014 | -37,629 | -27,833 | -9,111 | -2,567 |
| General Advertising Expenses | 930 | 5,093,710 | 2,900,754 | 86,380 | 1,059,216 | 510,902 | 377,894 | 123,709 | 34,854 |
| Miscellaneous General Expenses | 930 | 107,111 | 60,997 | 1,816 | 22,273 | 10,743 | 7,946 | 2,601 | 733 |
| Rents | 931 | 687,396 | 391,457 | 11,657 | 142,941 | 68,946 | 50,997 | 16,695 | 4,704 |
| Misc Expenses - Credit | 932 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal | 927-932 | 6,839,276 | 3,894,815 | 115,982 | 1,422,199 | 685,984 | 507,395 | 166,103 | 46,799 |
| TOTAL A&G EXPENSES | 920-932 | 75,722,484 | 43,122,264 | 1,284,116 | 15,746,177 | 7,595,014 | 5,617,728 | 1,839,044 | 518,141 |
| TOTAL OPERATING EXPENSES | | 638,825,490 | 305,211,628 | 9,321,160 | 133,931,144 | 85,257,659 | 73,538,686 | 28,365,210 | 3,200,003 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**



| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| II. DEPRECIATION EXPENSE | | | | | | | | | |
| Intangible | 301-303 | 13,277,153 | 7,591,633 | 226,018 | 2,755,430 | 1,334,898 | 984,913 | 263,895 | 120,366 |
| Production - Steam | 500-511 | 60,024,743 | 30,179,189 | 943,046 | 13,630,703 | 7,517,151 | 5,585,177 | 2,166,051 | 3,426 |
| Production - Other | 546-557 | 12,557,762 | 6,410,561 | 200,422 | 2,884,369 | 1,535,481 | 1,104,474 | 422,455 | 0 |
| Transmission | 565 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Land & Rights | 360 | 86,658 | 45,700 | 1,421 | 20,619 | 10,568 | 8,284 | 0 | 66 |
| Structures & Improvements | 361 | 185,998 | 98,087 | 3,051 | 44,256 | 22,682 | 17,780 | 0 | 142 |
| Station Equipment | 362 | 2,445,508 | 1,289,651 | 40,109 | 581,884 | 298,230 | 233,774 | 0 | 1,861 |
| Poles, Towers, & Fixtures | 364 | 3,451,385 | 2,529,733 | 68,532 | 489,534 | 156,711 | 120,051 | 0 | 86,824 |
| Overhead Conductors & Devices | 365 | 2,779,481 | 1,667,189 | 49,144 | 578,304 | 271,265 | 211,892 | 1 | 1,686 |
| Underground Conduit | 366 | 750,665 | 638,390 | 16,387 | 65,255 | 1,255 | 31 | 0 | 29,347 |
| Underground Conductors & Devices | 367 | 4,999,675 | 3,296,286 | 93,087 | 881,279 | 364,119 | 282,829 | 0 | 82,076 |
| Line Transformers | 368 | 4,903,883 | 2,969,090 | 86,887 | 989,183 | 456,343 | 356,215 | 0 | 46,165 |
| Services | 369 | 1,916,596 | 1,629,936 | 41,840 | 166,609 | 3,205 | 78 | 0 | 74,928 |
| Meters | 370 | 2,037,023 | 1,494,221 | 38,357 | 464,490 | 0 | 39,419 | 536 | 0 |
| Street Lighting & Signal Systems | 373 | 194,790 | 58,737 | 1,828 | 26,492 | 13,651 | 10,574 | 3,713 | 79,796 |
| Distribution Plant Net Salvage | 403 | 5,407,146 | 3,091,707 | 92,046 | 1,122,154 | 543,640 | 401,108 | 107,472 | 49,019 |
| General | EDST | 14,684,437 | 8,396,293 | 249,974 | 3,047,485 | 1,476,388 | 1,089,307 | 291,866 | 133,124 |
| TOTAL DEPRECIATION EXPENSES | | 129,702,903 | 71,386,403 | 2,152,149 | 27,748,046 | 14,005,587 | 10,445,904 | 3,255,991 | 708,823 |
| III. TAXES | | | | | | | | | |
| A. GENERAL TAXES | | | | | | | | | |
| Payroll Taxes | 408 | 5,290,439 | 3,053,139 | 90,448 | 1,084,749 | 518,177 | 379,593 | 124,806 | 39,526 |
| PropertyTaxes - Production | 408 | 14,193,015 | 7,245,335 | 226,520 | 3,259,968 | 1,735,429 | 1,248,296 | 477,466 | 0 |
| PropertyTaxes - Transmission | 408 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PropertyTaxes - Distribution | 408 | 18,111,409 | 11,958,107 | 336,101 | 3,179,496 | 1,252,830 | 983,551 | 148 | 401,176 |
| PropertyTaxes - General | 408 | 3,070,559 | 1,755,689 | 52,270 | 637,238 | 308,717 | 227,777 | 61,030 | 27,837 |
| Business Activity Tax - Generation | 408 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Business Activity Tax - Transmission | 408 | 69,718 | 35,588 | 1,107 | 16,057 | 8,230 | 6,451 | 2,234 | 51 |
| Subtotal - General Taxes | | 40,735,140 | 24,047,858 | 706,446 | 8,177,508 | 3,823,383 | 2,845,668 | 665,685 | 468,590 |
| B. FRANCHISE AND REVENUE TAXES | | | | | | | | | |
| Franchise Tax T&D | 408.11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PSC Assessment | 408.12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Franchise Tax Prod | 408 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Franchise | 408.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Retail Sales & Other | 408.14 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Franchise & Gross Receipts | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Income Taxes - Current | | 33,355,599 | 19,072,121 | 567,814 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| Subtotal - Federal Income Taxes | 409-411 | 33,355,599 | 19,072,121 | 567,814 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| TOTAL TAXES | | 74,090,738 | 43,119,980 | 1,274,260 | 15,099,851 | 7,176,988 | 5,320,021 | 1,328,658 | 770,980 |
| TOTAL EXPENSES | | 842,619,131 | 419,718,011 | 12,747,569 | 176,779,041 | 106,440,234 | 89,304,612 | 32,949,858 | 4,679,806 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 Rat**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| IV. OPERATING REVENUES | | | | | | | | | |
| Revenues | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Production Other Rev | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Payment Charges | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Reconnect Charges-Missouri | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ot Elec Rev-Off-Sys | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rent From Elec Property-Mo | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Miscellaneous Service Revenues Retail | 451 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scrap Sales Revenues | 456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Electric Revenues | 447.5, 456.1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Electric Revenues - Misc Transmissic | 456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Electric - Ancillary | 147.4, 449.1, 456. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Excess Fac Revenues | 450-456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Operating Revenues | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gains/Losses from Energy Purchases | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Allowance for Funds During Construction | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interest on Customer Deposits | | -31,250 | -22,929 | -589 | -7,128 | 0 | -605 | 0 | 0 |
| V. NET INCOME | | -842,650,381 | -419,740,940 | -12,748,158 | -176,786,168 | -106,440,234 | -89,305,217 | -32,949,858 | -4,679,806 |
| Rate of Return | | -40.04% | -34.90% | -35.62% | -40.29% | -50.40% | -57.23% | -75.63% | -27.92% |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**



| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| SUMMARY REPORT | | | | | | | | | |
| OPERATING REVENUES | | | | | | | | | |
| Utility Sales Revenues | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interdepartmental Revenues | 448 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Operating Revenues | 450-456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Operating Revenues | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OPERATING EXPENSES | | | | | | | | | |
| Production | 500-555 | 421,678,184 | 179,918,084 | 5,619,086 | 89,291,886 | 64,400,174 | 57,673,688 | 23,457,608 | 1,317,657 |
| Transmission | 560-573 | 95,464,952 | 48,730,546 | 1,515,557 | 21,986,984 | 11,268,859 | 8,833,333 | 3,059,365 | 70,310 |
| Distribution | 580-599 | 24,085,317 | 15,400,761 | 434,374 | 4,634,914 | 1,673,202 | 1,373,080 | 951 | 568,033 |
| Customer Acctg & Service | 901-919 | 21,874,552 | 18,039,973 | 468,027 | 2,271,183 | 320,409 | 40,858 | 8,241 | 725,862 |
| Admin & General | 920-932 | 75,722,484 | 43,122,264 | 1,284,116 | 15,746,177 | 7,595,014 | 5,617,728 | 1,839,044 | 518,141 |
| Total Operating Expenses | | 638,825,490 | 305,211,628 | 9,321,160 | 133,931,144 | 85,257,659 | 73,538,686 | 28,365,210 | 3,200,003 |
| DEPRECIATION EXPENSES | 403 | 129,702,903 | 71,386,403 | 2,152,149 | 27,748,046 | 14,005,587 | 10,445,904 | 3,255,991 | 708,823 |
| TAXES OTHER THAN INCOME TAX | 408 | 40,735,140 | 24,047,858 | 706,446 | 8,177,508 | 3,823,383 | 2,845,668 | 665,685 | 468,590 |
| INCOME BEFORE INCOME TAXES | | -809,263,532 | -400,645,889 | -12,179,755 | -169,856,698 | -103,086,629 | -86,830,259 | -32,286,886 | -4,377,416 |
| INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Income Taxes - Current | | 33,355,599 | 19,072,121 | 567,814 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| Subtotal - Federal Income Taxes | 409-411 | 33,355,599 | 19,072,121 | 567,814 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| OPERATING INCOME | | -842,619,131 | -419,718,011 | -12,747,569 | -176,779,041 | -106,440,234 | -89,304,612 | -32,949,858 | -4,679,806 |
| Gains/Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Allowance for Funds During Construction | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interest on Customer Deposits | | -31,250 | -22,929 | -589 | -7,128 | 0 | -605 | 0 | 0 |
| NET INCOME | | -842,650,381 | -419,740,940 | -12,748,158 | -176,786,168 | -106,440,234 | -89,305,217 | -32,949,858 | -4,679,806 |
| RATE BASE | | 2,104,677,691 | 1,202,577,772 | 35,789,604 | 438,733,978 | 211,211,546 | 156,039,474 | 43,566,603 | 16,758,714 |
| RETURN ON RATE BASE | | -40.04% | -34.90% | -35.62% | -40.29% | -50.40% | -57.23% | -75.63% | -27.92% |
| Unitized Rate of Return | | 1.00 | 0.87 | 0.89 | 1.01 | 1.26 | 1.43 | 1.89 | 0.70 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Counterfactual COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 Rat**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| **REVENUE REQUIREMENTS** | | | | | | | | | |
| RATE OF RETURN | | 5.22% | 5.52% | 5.52% | 5.52% | 5.52% | 5.52% | 5.52% | 5.52% |
| Using Target for System | | | | | | | | | |
| RATE BASE | | 2,104,677,691 | 1,202,577,772 | 35,789,604 | 438,733,978 | 211,211,546 | 156,039,474 | 43,566,603 | 16,758,714 |
| OPERATING EXPENSES | | 638,825,490 | 305,211,628 | 9,321,160 | 133,931,144 | 85,257,659 | 73,538,686 | 28,365,210 | 3,200,003 |
| DEPRECIATION EXPENSE | | 129,702,903 | 71,386,403 | 2,152,149 | 27,748,046 | 14,005,587 | 10,445,904 | 3,255,991 | 708,823 |
| GENERAL TAXES | | 40,735,140 | 24,047,858 | 706,446 | 8,177,508 | 3,823,383 | 2,845,668 | 665,685 | 468,590 |
| Other costs (benefits), net of taxes | | 31,250 | 22,929 | 589 | 7,128 | 0 | 605 | 0 | 0 |
| Subtotal- Operating Costs to recover | | 809,294,783 | 400,668,818 | 12,180,344 | 169,863,826 | 103,086,629 | 86,830,864 | 32,286,886 | 4,377,416 |
| Target Return on Rate Base- After taxes | | 116,218,763 | 66,405,465 | 1,976,276 | 24,226,569 | 11,662,947 | 8,616,386 | 2,405,716 | 925,404 |
| Actual Historic FIT | | 33,355,599 | 19,072,121 | 567,814 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| Incremental Tax Due to Target ROR | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal- Rev Req before Uncollectible Adj. | | 958,869,144 | 486,146,405 | 14,724,434 | 201,012,738 | 118,103,181 | 97,921,603 | 35,355,574 | 5,605,210 |
| Proforma Incr for Uncollect. Calc | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ECCR & Prop Tax Surcharge | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL REVENUE REQUIREMENT | | 958,869,144 | 486,146,405 | 14,724,434 | 201,012,738 | 118,103,181 | 97,921,603 | 35,355,574 | 5,605,210 |

# Exhibit HEO - 7

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 R**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| I. ELECTRIC PLANT IN SERVICE | | | | | | | | | |
| A. INTANGIBLE PLANT | | | | | | | | | |
| Intangible Plant | 301-303 | 160,246,771 | 92,500,491 | 2,441,155 | 33,006,195 | 16,114,538 | 11,847,834 | 3,184,513 | 1,152,044 |
| Subtotal - INTANGIBLE PLANT | 301-303 | 160,246,771 | 92,500,491 | 2,441,155 | 33,006,195 | 16,114,538 | 11,847,834 | 3,184,513 | 1,152,044 |
| B. PRODUCTION PLANT | | | | | | | | | |
| STEAM PRODUCTION PLANT | | | | | | | | | |
| Land & Land Rights | 310 | 6,057,619 | 3,121,060 | 67,949 | 1,391,363 | 740,686 | 532,776 | 203,784 | 0 |
| StructuresImprovements | 311 | 195,860,951 | 100,913,207 | 2,197,000 | 44,986,944 | 23,948,596 | 17,226,257 | 6,588,948 | 0 |
| Boiler Plant Equipment | 312 | 1,000,007,373 | 515,232,618 | 11,217,222 | 229,689,865 | 122,274,363 | 87,952,109 | 33,641,196 | 0 |
| Reactor Plant Equipment | 322 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Turbogenerator Units | 314 | 294,774,517 | 151,876,326 | 3,306,527 | 67,706,220 | 36,043,100 | 25,925,849 | 9,916,494 | 0 |
| Accessory Electric Equipment | 315 | 134,465,967 | 69,280,741 | 1,508,323 | 30,885,242 | 16,441,619 | 11,826,478 | 4,523,563 | 0 |
| Miscellaneous Power Plant Equipment | 316 | 25,580,106 | 13,179,608 | 286,936 | 5,875,448 | 3,127,768 | 2,249,808 | 860,539 | 0 |
| Sundt/SPV/SGS1 Acquisition Adjustment | 114 | -31,854,390 | -16,412,300 | -357,315 | -7,316,577 | -3,894,947 | -2,801,640 | -1,071,612 | 0 |
| Electric Plant Purchased or Sold | 102 | 15,029 | 7,744 | 169 | 3,452 | 1,838 | 1,322 | 506 | 0 |
| OTHER PRODUCTION PLANT | | | | | | | | | |
| Land and Land Rights | 340 | 1,873,363 | 965,211 | 21,014 | 430,289 | 229,063 | 164,765 | 63,022 | 0 |
| Structures and Improvements | 341 | 21,065,337 | 10,853,469 | 236,293 | 4,838,459 | 2,575,732 | 1,852,727 | 708,658 | 0 |
| Boiler Plant Equipment | 342 | 17,936,074 | 9,241,182 | 201,191 | 4,119,704 | 2,193,106 | 1,577,504 | 603,387 | 0 |
| Reactor Plant Equipment | 343 | 181,875,041 | 93,707,262 | 2,040,118 | 41,774,546 | 22,238,491 | 15,996,175 | 6,118,449 | 0 |
| Engines and Generators | 344 | 244,472,493 | 125,959,274 | 2,742,282 | 56,152,440 | 29,892,498 | 21,501,713 | 8,224,286 | 0 |
| Turbogenerator Units | 345 | 12,398,839 | 6,388,239 | 139,080 | 2,847,867 | 1,516,049 | 1,090,496 | 417,109 | 0 |
| Accessory Electric Equipment | 346&347 | 13,743,196 | 7,080,891 | 154,159 | 3,156,650 | 1,680,428 | 1,208,734 | 462,334 | 0 |
| Misc. Power Plant Equipment | 114 | -37,278,677 | -19,207,049 | -418,160 | -8,562,471 | -4,558,193 | -3,278,714 | -1,254,090 | 0 |
| Subtotal - PRODUCTION PLANT | 304-346 | 2,080,992,837 | 1,072,187,482 | 23,342,786 | 477,979,440 | 254,450,197 | 183,026,359 | 70,006,572 | 0 |
| C. TRANSMISSION PLANT | | | | | | | | | |
| Land and Land Rights | 350 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Structures and Improvements | 352 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Station Equipment | 353 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Towers and Fixtures | 354 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Poles and Fixtures | 355 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Overhead Conductors and Devices | 356 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Underground Conduit | 357 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Underground Conductors and Devices | 358 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Roads and Trails | 359 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - TRANSMISSION PLANT | 350-359 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 R**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| D. DISTRIBUTION PLANT | | | | | | | | | |
| Land and Land Rights | 360 | 11,605,107 | 6,073,523 | 236,825 | 2,761,319 | 1,415,243 | 1,109,368 | 0 | 8,830 |
| Structures and Improvements | 361 | 11,835,474 | 6,194,085 | 241,526 | 2,816,132 | 1,443,336 | 1,131,389 | 0 | 9,005 |
| Station Equipment | 362 | 161,677,439 | 84,613,750 | 3,299,346 | 38,469,527 | 19,716,560 | 15,455,241 | 0 | 123,017 |
| Compressor Station Equipment | 363 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Poles, Towers and Fixtures | 364 | 233,534,842 | 170,831,968 | 4,977,315 | 33,123,849 | 10,603,690 | 8,123,174 | 0 | 5,874,847 |
| Overhead Conductors and Devices | 365 | 183,006,168 | 107,903,424 | 3,787,383 | 37,945,458 | 17,858,051 | 13,951,321 | 0 | 1,560,531 |
| Underground Conduit | 366 | 61,247,158 | 52,086,600 | 1,337,060 | 5,324,180 | 102,415 | 2,495 | 0 | 2,394,407 |
| Underground Conductors and Devices | 367 | 304,496,075 | 200,032,657 | 6,390,874 | 53,672,692 | 22,175,997 | 17,225,188 | 0 | 4,998,668 |
| Line Transformers | 368 | 281,381,714 | 171,852,350 | 5,902,100 | 56,998,305 | 26,189,309 | 20,439,489 | 160 | 0 |
| Services | 369 | 134,848,680 | 114,679,759 | 2,943,823 | 11,722,318 | 225,488 | 5,494 | 0 | 5,271,798 |
| Meters | 370 | 46,154,903 | 33,856,083 | 869,084 | 10,524,428 | 0 | 893,157 | 12,152 | 0 |
| Installed on Cust Premise PR_L | 371 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Property on Customers Premise | 372 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Street Lighting and Signals | 373 | 11,995,791 | 0 | 0 | 0 | 0 | 0 | 0 | 11,995,791 |
| Subtotal - DISTRIBUTION PLANT | 374-387 | 1,441,783,351 | 948,124,199 | 29,985,336 | 253,358,208 | 99,730,087 | 78,336,315 | 12,311 | 32,236,894 |
| E. GENERAL PLANT | | | | | | | | | |
| General Plant | 389-399 | 314,077,737 | 180,174,621 | 4,755,846 | 65,181,072 | 31,577,691 | 23,298,616 | 6,242,578 | 2,847,314 |
| Subtotal - GENERAL PLANT | 389-399 | 314,077,737 | 180,174,621 | 4,755,846 | 65,181,072 | 31,577,691 | 23,298,616 | 6,242,578 | 2,847,314 |
| TOTAL PLANT IN SERVICE | 101 | 3,997,100,696 | 2,292,986,793 | 60,525,123 | 829,524,916 | 401,872,513 | 296,509,125 | 79,445,974 | 36,236,252 |
| ADDITIONS TO UTILITY PLANT | | | | | | | | | |
| Energy Conservation Programs | 182.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Property Held for Future Use | 105 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Construction Work in Progress | 107 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Nuclear Plant Costs - Calvert Cliffs | 182.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Additions to Utility Plant | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL UTILITY PLANT | | 3,997,100,696 | 2,292,986,793 | 60,525,123 | 829,524,916 | 401,872,513 | 296,509,125 | 79,445,974 | 36,236,252 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 R**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| II. DEPRECIATION RESERVE | | | | | | | | | |
| Intangible | 301-303 | -119,977,698 | -68,826,706 | -1,816,733 | -24,899,170 | -12,062,678 | -8,900,072 | -2,384,665 | -1,087,674 |
| Production | 304-359 | -796,297,495 | -410,275,418 | -8,932,180 | -182,900,116 | -97,366,051 | -70,035,528 | -26,788,203 | 0 |
| Transmission | 350-359 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Land and Land Rights | 360 | -3,862,742 | -2,021,563 | -78,827 | -919,101 | -471,061 | -369,251 | 0 | -2,939 |
| Structures and Improvements | 361 | -3,279,743 | -1,716,451 | -66,930 | -780,382 | -399,965 | -313,521 | 0 | -2,495 |
| Station Equipment | 362 | -54,387,561 | -28,463,684 | -1,109,885 | -12,940,975 | -6,632,562 | -5,199,073 | 0 | -41,382 |
| Compressor Station Equipment | 363 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Poles, Towers and Fixtures | 364 | -87,160,606 | -63,758,442 | -1,857,649 | -12,362,587 | -3,957,542 | -3,031,756 | 0 | -2,192,629 |
| Overhead Conductors and Devices | 365 | -71,943,372 | -42,923,271 | -1,501,841 | -14,968,663 | -7,021,347 | -5,484,567 | -34 | -43,650 |
| Underground Conduit | 366 | -27,348,184 | -23,257,796 | -597,026 | -2,377,362 | -45,730 | -1,114 | 0 | -1,069,155 |
| Underground Conductors and Devices | 367 | -141,085,166 | -92,683,101 | -2,961,147 | -24,868,697 | -10,275,023 | -7,981,116 | 0 | -2,316,082 |
| Line Transformers | 368 | -135,774,711 | -81,792,515 | -2,818,895 | -27,387,686 | -12,634,865 | -9,862,583 | 0 | -1,278,167 |
| Services | 369 | -52,591,903 | -44,725,886 | -1,148,111 | -4,571,784 | -87,942 | -2,143 | 0 | -2,056,037 |
| Meters | 370 | 4,020,491 | 2,949,157 | 75,705 | 916,769 | 0 | 77,802 | 1,059 | 0 |
| Street Lighting and Signals | 373 | -5,781,491 | 0 | 0 | 0 | 0 | 0 | 0 | -5,781,491 |
| General | 389-398 | -86,548,234 | -49,649,477 | -1,310,536 | -17,961,498 | -8,701,646 | -6,420,239 | -1,720,224 | -784,615 |
| Subtotal-DEPRECIATION RESERVE | | -1,582,018,414 | -907,145,153 | -24,124,054 | -326,021,251 | -159,656,413 | -117,523,160 | -30,892,067 | -16,656,315 |
| Dep. Res.- adjust for 13 month avg. | 108.9 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL RESERVE FOR DEPRECIATION | 108 | -1,582,018,414 | -907,145,153 | -24,124,054 | -326,021,251 | -159,656,413 | -117,523,160 | -30,892,067 | -16,656,315 |
| III. OTHER RATE BASE ITEMS | | | | | | | | | |
| Cash Working Capital | n/a | -10,528,676 | -6,039,907 | -159,428 | -2,185,033 | -1,058,564 | -781,028 | -209,267 | -95,449 |
| Fuel Inventory | 151, 152 | 25,107,584 | 12,936,151 | 281,635 | 5,766,915 | 3,069,991 | 2,208,249 | 844,643 | 0 |
| Materials & Supplies | 154, 163 | 77,125,097 | 44,243,776 | 1,167,848 | 16,005,899 | 7,754,235 | 5,721,221 | 1,532,931 | 699,188 |
| Prepayments | 165 | 9,439,165 | 4,550,191 | 97,286 | 1,978,941 | 1,259,751 | 1,086,594 | 419,119 | 47,283 |
| Customer Advances for Construction | 252 | -11,046,099 | -5,782,077 | -225,461 | -2,628,814 | -1,347,330 | -1,056,133 | 0 | -6,284 |
| Customer Deposits | 235 | -19,400,461 | -10,155,166 | -395,981 | -4,617,032 | -2,366,340 | -1,854,906 | 0 | -11,036 |
| Deferred Credits - Asset Retirement - tax cr | 230&253 | -2,630,793 | -1,509,187 | -39,836 | -545,973 | -264,503 | -195,155 | -52,289 | -23,850 |
| Plant Held for Future Use - Transmission Pl | 105 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Regulatory Assets | 182 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Regulatory Liabilities | 254 | 25,112,104 | 14,405,872 | 380,254 | 5,211,556 | 2,524,796 | 1,862,842 | 499,126 | 227,657 |
| ADIT | 190 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ADIT - Other Property | 283 | -403,582,512 | -231,520,154 | -6,111,150 | -83,756,146 | -40,576,591 | -29,938,174 | -8,021,566 | -3,658,731 |
| Total - OTHER RATE BASE ITEMS | 131-283 | -310,404,592 | -178,870,500 | -5,004,832 | -64,769,687 | -31,004,554 | -22,946,491 | -4,987,304 | -2,821,223 |
| TOTAL RATE BASE | | 2,104,677,691 | 1,206,971,139 | 31,396,237 | 438,733,978 | 211,211,546 | 156,039,474 | 43,566,603 | 16,758,714 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**



| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| I. OPERATING AND MAINTENANCE EXPE | | | | | | | | | |
| A. PRODUCTION EXPENSES | | | | | | | | | |
| Operation Supervision & Engineering | 500 | 9,802,746 | 5,050,657 | 109,959 | 2,251,575 | 1,198,616 | 862,166 | 329,774 | 0 |
| PPFAC - FUEL | 501 | 303,925,690 | 122,233,868 | 1,312,978 | 62,245,531 | 50,002,169 | 47,317,185 | 19,496,303 | 1,317,657 |
| Steam Expenses | 502 | 21,363,731 | 11,007,210 | 239,640 | 4,906,996 | 2,612,217 | 1,878,971 | 718,696 | 0 |
| Electric Expenses | 505 | 2,800,879 | 1,443,094 | 31,418 | 643,329 | 342,473 | 246,341 | 94,224 | 0 |
| Miscellaneous Steam Power Expenses | 506 | 4,495,150 | 2,316,031 | 50,423 | 1,032,483 | 549,638 | 395,355 | 151,221 | 0 |
| Rents | 507 | 14,157,699 | 7,294,455 | 158,809 | 3,251,856 | 1,731,111 | 1,245,190 | 476,278 | 0 |
| Maintenance Supervision & Engineering | 510 | 4,146,264 | 2,136,275 | 46,509 | 952,348 | 506,978 | 364,670 | 139,484 | 0 |
| Maintenance of Structures | 511 | 3,573,450 | 1,841,145 | 40,084 | 820,779 | 436,938 | 314,290 | 120,214 | 0 |
| Maintenance of Boiler Plant | 512 | 30,090,681 | 15,503,586 | 337,531 | 6,911,474 | 3,679,292 | 2,646,519 | 1,012,279 | 0 |
| Maintenance of Electric Plant | 513 | 5,140,971 | 2,648,777 | 57,667 | 1,180,820 | 628,604 | 452,156 | 172,947 | 0 |
| Maintenance Miscellaneous Steam Plant | 514 | 6,697,663 | 3,450,829 | 75,129 | 1,538,374 | 818,946 | 589,069 | 225,316 | 0 |
| FAS 143 Accretion Expense | 411 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Loss from Disposition of Utility Plant | 412 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Other Production | 500-554 | 406,194,926 | 174,925,925 | 2,460,146 | 85,735,565 | 62,506,983 | 56,311,913 | 22,936,737 | 1,317,657 |
| Operation Supervision & Engineering | 546 | 7,586,523 | 3,908,795 | 85,099 | 1,742,535 | 927,630 | 667,246 | 255,218 | 0 |
| PPFAC - Fuel | 547 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Generation Exp & Misc Other Power Gener. | 548 & 549 | 1,498,181 | 771,906 | 16,805 | 344,114 | 183,188 | 131,767 | 50,400 | 0 |
| Rents | 550 | 10,337 | 5,326 | 116 | 2,374 | 1,264 | 909 | 348 | 0 |
| Maintenance Supervision & Engineering | 551 | 2,193 | 1,130 | 25 | 504 | 268 | 193 | 74 | 0 |
| Maintenance Structures, Generating, Other | 552-554 | 5,740,669 | 2,957,758 | 64,394 | 1,318,564 | 701,932 | 504,900 | 193,122 | 0 |
| Other Expenses | 557 | 645,356 | 332,506 | 7,239 | 148,231 | 78,910 | 56,760 | 21,710 | 0 |
| Subtotal | 556-557 | 15,483,258 | 7,977,421 | 173,678 | 3,556,321 | 1,893,192 | 1,361,775 | 520,871 | 0 |
| TOTAL PRODUCTION EXPENSE | 500-557 | 421,678,184 | 182,903,346 | 2,633,824 | 89,291,886 | 64,400,174 | 57,673,688 | 23,457,608 | 1,317,657 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 R**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| B. TRANSMISSION EXPENSE | | | | | | | | | |
| Supervision and Engineering | 560 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Load Dispatching | 561 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Station Expenses | 562 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Overhead Line Expenses | 563 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Underground Lines Expenses | 564 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transmission by Others | 565 | 95,464,952 | 48,360,385 | 1,885,717 | 21,986,984 | 11,268,859 | 8,833,333 | 3,059,365 | 70,310 |
| Miscellaneous Expenses | 566 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rents | 567 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Supervision and Engineering | 568 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Structures | 569 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Station Equipment | 570 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Overhead Lines | 571 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Underground Lines | 572 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Misc Maintenance - Credits | 573 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL TRANSMISSION EXPENSES | 560-573 | 95,464,952 | 48,360,385 | 1,885,717 | 21,986,984 | 11,268,859 | 8,833,333 | 3,059,365 | 70,310 |
| C. DISTRIBUTION EXPENSE | | | | | | | | | |
| Operation Supervision & Engineering | 580 | 719,344 | 456,071 | 14,731 | 142,377 | 53,179 | 43,452 | 27 | 9,508 |
| Load Dispatching | 581 | 701,361 | 367,127 | 14,315 | 166,914 | 85,547 | 67,058 | 0 | 399 |
| Station Expenses | 582 | 263,040 | 137,688 | 5,369 | 62,600 | 32,084 | 25,150 | 0 | 150 |
| Overhead Line Expenses | 583 | 831,367 | 490,188 | 17,205 | 172,380 | 81,126 | 63,379 | 0 | 7,089 |
| Underground Line Expenses | 584 | 247,581 | 162,644 | 5,196 | 43,640 | 18,031 | 14,006 | 0 | 4,064 |
| Street Light and Signal Systems | 585 | 219,325 | 0 | 0 | 0 | 0 | 0 | 0 | 219,325 |
| Meter Expenses | 586 | 2,764,693 | 2,027,990 | 52,058 | 630,416 | 0 | 53,500 | 728 | 0 |
| Customer Installation Expenses | 587 | 59,339 | 43,527 | 1,117 | 13,531 | 0 | 1,148 | 16 | 0 |
| Misc. Distribution Expenses | 588 | 11,306,668 | 7,439,817 | 235,264 | 1,984,910 | 782,122 | 614,015 | 92 | 250,448 |
| Rents | 589 | 834,309 | 548,977 | 17,360 | 146,465 | 57,712 | 45,308 | 7 | 18,480 |
| Maint Supervision & Engineering | 590 | 1,054,638 | 668,651 | 21,597 | 208,741 | 77,966 | 63,705 | 40 | 13,939 |
| Maint of Structures | 591 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Station Equipment | 592 | 1,385,470 | 725,084 | 28,273 | 329,659 | 168,958 | 132,441 | 0 | 1,054 |
| Maintenance of Overhead Lines | 593 | 2,298,053 | 1,354,969 | 47,559 | 476,490 | 224,248 | 175,190 | 0 | 19,596 |
| Maintenance of Underground Lines | 594 | 132,130 | 86,800 | 2,773 | 23,290 | 9,623 | 7,475 | 0 | 2,169 |
| Maintenance of Line Transformers | 595 | 155,703 | 95,095 | 3,266 | 31,540 | 14,492 | 11,310 | 0 | 0 |
| Maintenance of Street Lights | 596 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Maintenance of Meters | 597 | 127,603 | 93,601 | 2,403 | 29,097 | 0 | 2,469 | 34 | 0 |
| Maintenance of Misc. Plant | 598 | 576,162 | 379,116 | 11,989 | 101,146 | 39,855 | 31,289 | 5 | 12,762 |
| Regulatory Asset Amortization | 407 | 408,531 | 268,814 | 8,501 | 71,718 | 28,260 | 22,186 | 3 | 9,049 |
| Subtotal - DISTRIBUTION EXPENSES | 580-599 | 24,085,317 | 15,346,159 | 488,976 | 4,634,914 | 1,673,202 | 1,373,080 | 951 | 568,033 |
| Total - OPER. AND MAINT. EXPENSE | 500-599 | 541,228,453 | 246,609,891 | 5,008,518 | 115,913,784 | 77,342,236 | 67,880,101 | 26,517,924 | 1,956,000 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 R**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| D. CUSTOMER ACCOUNTS AND SERVIC | | | | | | | | | |
| Supervision | 901 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Meter Reading Expenses | 902 | 1,538,844 | 1,358,784 | 34,880 | 138,892 | 2,672 | 3,255 | 362 | 0 |
| Customer Records & Collection Expense | 903 | 18,299,064 | 15,527,614 | 398,593 | 1,587,199 | 30,531 | 37,194 | 4,133 | 713,800 |
| Uncollectible Accounts | 904 | 1,723,975 | 909,246 | 9,767 | 518,272 | 286,690 | 0 | 0 | 0 |
| Misc Customer Accounts Expenses | 905 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Customer Accounts Expense | 901-905 | 21,561,883 | 17,795,645 | 443,240 | 2,244,363 | 319,893 | 40,448 | 4,494 | 713,800 |
| Customer Assistance Exp Electric | (907, 908) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Supervision | 909 | 202,797 | 168,941 | 4,337 | 17,269 | 332 | 405 | 3,747 | 7,766 |
| Customer Assistance Expenses | 910 | 109,873 | 93,439 | 2,399 | 9,551 | 184 | 4 | 0 | 4,295 |
| Information, Instructional Advertising | 911 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Misc Customer Serv & Inform Expen | 912 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rents | 913 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Customer Service & Info. | 909-913 | 312,669 | 262,380 | 6,735 | 26,820 | 516 | 409 | 3,747 | 12,062 |
| Supervision | 915 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demonstrating & Selling Expenses | 916 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Advertising Expenses | 917 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Miscellaneous Sales Expenses | 918 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Sales Expense | 915-919 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total - CUST ACCTS, SERVS, & SALES E | 901-919 | 21,874,552 | 18,058,025 | 449,975 | 2,271,183 | 320,409 | 40,858 | 8,241 | 725,862 |

TUCSON I
TEST PE
2016 R

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| E. ADMINISTRATIVE AND GENERAL | | | | | | | | | |
| LABOR RELATED EXPENSES | | | | | | | | | |
| Administrative & General Salaries | 920 | 29,996,909 | 17,140,984 | 445,330 | 6,238,598 | 3,008,207 | 2,225,437 | 737,737 | 200,614 |
| Office Supplies & Expenses | 921 | 11,749,828 | 6,714,146 | 174,436 | 2,443,667 | 1,178,319 | 871,707 | 288,973 | 78,581 |
| Admin Expenses Transferred-Credit | 922 | -9,762,376 | -5,578,466 | -144,931 | -2,030,327 | -979,009 | -724,260 | -240,094 | -65,289 |
| Outside Services Employed | 923 | 11,102,007 | 6,343,965 | 164,819 | 2,308,937 | 1,113,353 | 823,645 | 273,040 | 74,248 |
| Employee Pensions and Benefits | 926 | 21,312,336 | 12,178,402 | 316,400 | 4,432,427 | 2,137,284 | 1,581,138 | 524,151 | 142,533 |
| Subtotal - O & M Accounts 920-923,926 | 920-926 | 64,398,703 | 36,799,030 | 956,055 | 13,393,301 | 6,458,154 | 4,777,668 | 1,583,807 | 430,688 |
| PLANT RELATED EXPENSES | | | | | | | | | |
| Property Insurance | 924 | 2,403,431 | 1,378,758 | 36,393 | 498,788 | 241,643 | 178,289 | 47,770 | 21,789 |
| Injuries and Damages | 925 | 2,054,306 | 1,178,478 | 31,107 | 426,334 | 206,542 | 152,391 | 40,831 | 18,624 |
| Maintenance of General Plant (also acct 93 | 935 | 26,768 | 15,356 | 405 | 5,555 | 2,691 | 1,986 | 532 | 243 |
| Subtotal - O & M Accounts 924-925 | 924,925,935 | 4,484,505 | 2,572,593 | 67,906 | 930,677 | 450,877 | 332,665 | 89,134 | 40,655 |
| OTHER A&G EXPENSES | | | | | | | | | |
| Franchise Requirements | 927 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Regulatory Commission Expenses | 928 | 1,326,223 | 758,030 | 19,715 | 275,783 | 133,021 | 98,390 | 32,209 | 9,075 |
| Duplicate Charges-Credit | 929 | -375,164 | -214,433 | -5,577 | -78,014 | -37,629 | -27,833 | -9,111 | -2,567 |
| General Advertising Expenses | 930 | 5,093,710 | 2,911,415 | 75,719 | 1,059,216 | 510,902 | 377,894 | 123,709 | 34,854 |
| Miscellaneous General Expenses | 930 | 107,111 | 61,221 | 1,592 | 22,273 | 10,743 | 7,946 | 2,601 | 733 |
| Rents | 931 | 687,396 | 392,896 | 10,218 | 142,941 | 68,946 | 50,997 | 16,695 | 4,704 |
| Misc Expenses - Credit | 932 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal | 927-932 | 6,839,276 | 3,909,130 | 101,667 | 1,422,199 | 685,984 | 507,395 | 166,103 | 46,799 |
| TOTAL A&G EXPENSES | | 75,722,484 | 43,280,753 | 1,125,628 | 15,746,177 | 7,595,014 | 5,617,728 | 1,839,044 | 518,141 |
| TOTAL OPERATING EXPENSES | 920-932 | 638,825,490 | 307,948,668 | 6,584,120 | 133,931,144 | 85,257,659 | 73,538,686 | 28,365,210 | 3,200,003 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 R**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| II. DEPRECIATION EXPENSE | | | | | | | | | |
| Intangible | 301-303 | 13,277,153 | 7,616,605 | 201,046 | 2,755,430 | 1,334,898 | 984,913 | 263,895 | 120,366 |
| Production - Steam | 500-511 | 60,024,743 | 30,464,212 | 658,022 | 13,630,703 | 7,517,151 | 5,585,177 | 2,166,051 | 3,426 |
| Production - Other | 546-557 | 12,557,762 | 6,470,121 | 140,862 | 2,884,369 | 1,535,481 | 1,104,474 | 422,455 | 0 |
| Transmission | 565 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Land & Rights | 360 | 86,658 | 45,352 | 1,768 | 20,619 | 10,568 | 8,284 | 0 | 66 |
| Structures & Improvements | 361 | 185,998 | 97,342 | 3,796 | 44,256 | 22,682 | 17,780 | 0 | 142 |
| Station Equipment | 362 | 2,445,508 | 1,279,855 | 49,905 | 581,884 | 298,230 | 233,774 | 0 | 1,861 |
| Poles, Towers, & Fixtures | 364 | 3,451,385 | 2,524,706 | 73,559 | 489,534 | 156,711 | 120,051 | 0 | 86,824 |
| Overhead Conductors & Devices | 365 | 2,779,481 | 1,658,310 | 58,023 | 578,304 | 271,265 | 211,892 | 1 | 1,686 |
| Underground Conduit | 366 | 750,665 | 638,390 | 16,387 | 65,255 | 1,255 | 31 | 0 | 29,347 |
| Underground Conductors & Devices | 367 | 4,999,675 | 3,284,437 | 104,935 | 881,279 | 364,119 | 282,829 | 0 | 82,076 |
| Line Transformers | 368 | 4,903,883 | 2,954,165 | 101,812 | 989,183 | 456,343 | 356,215 | 0 | 46,165 |
| Services | 369 | 1,916,596 | 1,629,936 | 41,840 | 166,609 | 3,205 | 78 | 0 | 74,928 |
| Meters | 370 | 2,037,023 | 1,494,221 | 38,357 | 464,490 | 0 | 39,419 | 536 | 0 |
| Street Lighting & Signal Systems | 373 | 194,790 | 58,430 | 2,136 | 26,492 | 13,651 | 10,574 | 3,713 | 79,796 |
| Distribution Plant Net Salvage | 403 | 5,407,146 | 3,101,877 | 81,876 | 1,122,154 | 543,640 | 401,108 | 107,472 | 49,019 |
| General | EDST | 14,684,437 | 8,423,911 | 222,356 | 3,047,485 | 1,476,388 | 1,089,307 | 291,866 | 133,124 |
| TOTAL DEPRECIATION EXPENSES | | 129,702,903 | 71,741,871 | 1,796,681 | 27,748,046 | 14,005,587 | 10,445,904 | 3,255,991 | 708,823 |
| III. TAXES | | | | | | | | | |
| A. GENERAL TAXES | | | | | | | | | |
| Payroll Taxes | 408 | 5,290,439 | 3,068,612 | 74,976 | 1,084,749 | 518,177 | 379,593 | 124,806 | 39,526 |
| PropertyTaxes - Production | 408 | 14,193,015 | 7,312,650 | 159,205 | 3,259,968 | 1,735,429 | 1,248,296 | 477,466 | 0 |
| PropertyTaxes - Transmission | 408 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PropertyTaxes - Distribution | 408 | 18,111,409 | 11,917,353 | 376,854 | 3,179,496 | 1,252,830 | 983,551 | 148 | 401,176 |
| PropertyTaxes - General | 408 | 3,070,559 | 1,761,464 | 46,495 | 637,238 | 308,717 | 227,777 | 61,030 | 27,837 |
| Business Activity Tax - Generation | 408 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Business Activity Tax - Transmission | 408 | 69,718 | 35,318 | 1,377 | 16,057 | 8,230 | 6,451 | 2,234 | 51 |
| Subtotal - General Taxes | | 40,735,140 | 24,095,398 | 658,907 | 8,177,508 | 3,823,383 | 2,845,668 | 665,685 | 468,590 |
| B. FRANCHISE AND REVENUE TAXES | | | | | | | | | |
| Franchise Tax T&D | 408.11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| PSC Assessment | 408.12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Franchise Tax Prod | 408 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Franchise | 408.13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Retail Sales & Other | 408.14 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal - Franchise & Gross Receipts | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Income Taxes - Current | | 33,355,599 | 19,134,856 | 505,079 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| Subtotal - Federal Income Taxes | 409-411 | 33,355,599 | 19,134,856 | 505,079 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| TOTAL TAXES | | 74,090,738 | 43,230,254 | 1,163,986 | 15,099,851 | 7,176,988 | 5,320,021 | 1,328,658 | 770,980 |
| TOTAL EXPENSES | | 842,619,131 | 422,920,792 | 9,544,788 | 176,779,041 | 106,440,234 | 89,304,612 | 32,949,858 | 4,679,806 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**

**TUCSON I**
**TEST PE**
**2016 R**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| IV. OPERATING REVENUES | | | | | | | | | |
| Revenues | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Production Other Rev | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Payment Charges | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Reconnect Charges-Missouri | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ot Elec Rev-Off-Sys | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Rent From Elec Property-Mo | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Miscellaneous Service Revenues Retail | 451 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Scrap Sales Revenues | 456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Electric Revenues | 447.5, 456.1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Electric Revenues - Misc Transmissic | 456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Electric - Ancillary | 147.4, 449.1, 456. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Excess Fac Revenues | 450-456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Operating Revenues | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Gains/Losses from Energy Purchases | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Allowance for Funds During Construction | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interest on Customer Deposits | | -31,250 | -22,929 | -589 | -7,128 | 0 | -605 | 0 | 0 |
| V. NET INCOME | | -842,650,381 | -422,943,721 | -9,545,376 | -176,786,168 | -106,440,234 | -89,305,217 | -32,949,858 | -4,679,806 |
| Rate of Return | | -40.04% | -35.04% | -30.40% | -40.29% | -50.40% | -57.23% | -75.63% | -27.92% |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**

**TUCSON E**
**TEST PE**
**2016 R**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| SUMMARY REPORT | | | | | | | | | |
| OPERATING REVENUES | | | | | | | | | |
| Utility Sales Revenues | 440-446 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interdepartmental Revenues | 448 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Operating Revenues | 450-456 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total Operating Revenues | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| OPERATING EXPENSES | | | | | | | | | |
| Production | 500-555 | 421,678,184 | 182,903,346 | 2,633,824 | 89,291,886 | 64,400,174 | 57,673,688 | 23,457,608 | 1,317,657 |
| Transmission | 560-573 | 95,464,952 | 48,360,385 | 1,885,717 | 21,986,984 | 11,268,859 | 8,833,333 | 3,059,365 | 70,310 |
| Distribution | 580-599 | 24,085,317 | 15,346,159 | 488,976 | 4,634,914 | 1,673,202 | 1,373,080 | 951 | 568,033 |
| Customer Acctg & Service | 901-919 | 21,874,552 | 18,058,025 | 449,975 | 2,271,183 | 320,409 | 40,858 | 8,241 | 725,862 |
| Admin & General | 920-932 | 75,722,484 | 43,280,753 | 1,125,628 | 15,746,177 | 7,595,014 | 5,617,728 | 1,839,044 | 518,141 |
| Total Operating Expenses | | 638,825,490 | 307,948,668 | 6,584,120 | 133,931,144 | 85,257,659 | 73,538,686 | 28,365,210 | 3,200,003 |
| DEPRECIATION EXPENSES | 403 | 129,702,903 | 71,741,871 | 1,796,681 | 27,748,046 | 14,005,587 | 10,445,904 | 3,255,991 | 708,823 |
| TAXES OTHER THAN INCOME TAX | 408 | 40,735,140 | 24,095,398 | 658,907 | 8,177,508 | 3,823,383 | 2,845,668 | 665,685 | 468,590 |
| INCOME BEFORE INCOME TAXES | | -809,263,532 | -403,785,936 | -9,039,708 | -169,856,698 | -103,086,629 | -86,830,259 | -32,286,886 | -4,377,416 |
| INCOME TAXES | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Income Taxes - Current | | 33,355,599 | 19,134,856 | 505,079 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| Subtotal - Federal Income Taxes | 409-411 | 33,355,599 | 19,134,856 | 505,079 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| OPERATING INCOME | | -842,619,131 | -422,920,792 | -9,544,788 | -176,779,041 | -106,440,234 | -89,304,612 | -32,949,858 | -4,679,806 |
| Gains/Losses | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Allowance for Funds During Construction | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Interest on Customer Deposits | | -31,250 | -22,929 | -589 | -7,128 | 0 | -605 | 0 | 0 |
| NET INCOME | | -842,650,381 | -422,943,721 | -9,545,376 | -176,786,168 | -106,440,234 | -89,305,217 | -32,949,858 | -4,679,806 |
| RATE BASE | | 2,104,677,691 | 1,206,971,139 | 31,396,237 | 438,733,978 | 211,211,546 | 156,039,474 | 43,566,603 | 16,758,714 |
| RETURN ON RATE BASE | | -40.04% | -35.04% | -30.40% | -40.29% | -50.40% | -57.23% | -75.63% | -27.92% |
| Unitized Rate of Return | | 1.00 | 0.88 | 0.76 | 1.01 | 1.26 | 1.43 | 1.89 | 0.70 |

**TUCSON ELECTRIC POWER COMPANY**
**TEST PERIOD ENDING JUNE 30, 2015**
**2016 Rate Case Solar Class COSS**
**Allocation Phase**

**TUCSON (**
**TEST PE**
**2016 R**

| Account Description | Account Code | Total Allocated Dollars | Residential RES | Solar SOLAR | TOTAL General Service GS | Large Gen. Service GSL | Large Power Service LPS | 138 kV MINING | Lighting LIGHTING |
|---|---|---|---|---|---|---|---|---|---|
| **REVENUE REQUIREMENTS** | | | | | | | | | |
| RATE OF RETURN | | 5.22% | 5.52% | 5.52% | 5.52% | 5.52% | 5.52% | 5.52% | 5.52% |
| Using Target for System | | | | | | | | | |
| RATE BASE | | 2,104,677,691 | 1,206,971,139 | 31,396,237 | 438,733,978 | 211,211,546 | 156,039,474 | 43,566,603 | 16,758,714 |
| OPERATING EXPENSES | | 638,825,490 | 307,948,668 | 6,584,120 | 133,931,144 | 85,257,659 | 73,538,686 | 28,365,210 | 3,200,003 |
| DEPRECIATION EXPENSE | | 129,702,903 | 71,741,871 | 1,796,681 | 27,748,046 | 14,005,587 | 10,445,904 | 3,255,991 | 708,823 |
| GENERAL TAXES | | 40,735,140 | 24,095,398 | 658,907 | 8,177,508 | 3,823,383 | 2,845,668 | 665,685 | 468,590 |
| Other costs (benefits), net of taxes | | 31,250 | 22,929 | 589 | 7,128 | 0 | 605 | 0 | 0 |
| Subtotal- Operating Costs to recover | | 809,294,783 | 403,808,865 | 9,040,297 | 169,863,826 | 103,086,629 | 86,830,864 | 32,286,886 | 4,377,416 |
| Target Return on Rate Base- After taxes | | 116,218,763 | 66,648,063 | 1,733,677 | 24,226,569 | 11,662,947 | 8,616,386 | 2,405,716 | 925,404 |
| Actual Historic FIT | | 33,355,599 | 19,134,856 | 505,079 | 6,922,343 | 3,353,605 | 2,474,353 | 662,973 | 302,390 |
| Incremental Tax Due to Target ROR | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Subtotal- Rev Req before Uncollectible Adj. | | 958,869,144 | 489,591,785 | 11,279,053 | 201,012,738 | 118,103,181 | 97,921,603 | 35,355,574 | 5,605,210 |
| Proforma Incr for Uncollect. Calc | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ECCR & Prop Tax Surcharge | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| TOTAL REVENUE REQUIREMENT | | 958,869,144 | 489,591,785 | 11,279,053 | 201,012,738 | 118,103,181 | 97,921,603 | 35,355,574 | 5,605,210 |

# Exhibit HEO - 8

## Load Data Summary - Table 1

| Line No. | Load Information | kWh Annual | Notes |
|---|---|---|---|
| 1 | Residential Load | 3,677,255,630 | TEP Residential Load Profile (inc. solar) |
| 2 | Full Load for Solar Customers | 113,287,652 | Line 3 + Line 4 - Line 5 |
| 3 | Solar Production | 85,919,910 | Calculated (Rio Rico profile) |
| 4 | Delivered to Solar Customers | 73,269,926 | Metered |
| 5 | Excess | 45,902,184 | Metered |
| 6 | Load Net Solar | 3,603,985,704 | Line 1 - Line 4 |
| 7 | Counterfactual Load | 3,717,273,356 | Line 6 + Line 2 |
| 8 | Netted (Solar Power Consumed @ Premise) | 40,017,726 | Line 3 - Line 5 |

## Average Cost Data - Table 2

| Line No. | Load Information | $ | kWh | Avg. Cost ($/mWh) | Notes |
|---|---|---|---|---|---|
| 1 | Residential Full Production | $ 152,780,781 | 3,603,985,704 | $ 42.39 | Average embedded production costs for Residential sales net of solar customers |
| 2 | Avoided Fuel Cost | $ 1,116,525 | 40,017,726 | $ 27.90 | Average avoided cost of fuel related to solar energy consumed at premise |
| 3 | Residential Marginal | $ 98,397,088 | 3,603,985,704 | $ 27.30 | Average marginal cost for Residential energy sales net of solar |
| 4 | Marginal for Delivered Energy | $ 1,975,727 | 73,269,926 | $ 26.97 | Average marginal cost for energy delivered to solar customers |
| 5 | Marginal for Excess Energy | $ 1,129,968 | 45,902,184 | $ 24.62 | Average marginal cost for solar energy delivered to system |

## Subsidy Calculation - Table 3

| Subsidy Description | Annual ($) | Per Customer ($) | Notes |
|---|---|---|---|
| Arbitrage Subsidy | $ 107,787 | $ 11.18 | (Marginal Cost of Delivered - Marginal Cost Excess) * Excess Energy |
| Production Cost Subsidy | $ 708,139 | $ 73.42 | (Embedded Cost of Production - Marginal Cost Delivered) * Excess Energy |
| Subsidy Production vs Marginal Cost of Excess | $ 815,926 | $ 84.60 | Sum of above |
| Power Consumed "Netted" Subsidy | $ 579,913 | $ 60.13 | (Embedded Cost of Production - Avoided Fuel) * Energy Consumed at Premise |
| Total Subsidy | $ 1,395,839 | $ 144.72 | |
| Customer Count | | 9,645 | |