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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-12-0291 **STAFF'S NOTICE OF FILING RATE DESIGN DIRECT TESTIMONY**

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission") hereby submits the Direct Testimony, rate design, of Staff witness Howard S. Solganick (Public) in the above-referenced matter.

A confidential version of Howard S. Solganick's Direct Testimony will be provided under seal to the Commissioners, their Assistants, the assigned Administrative Law Judge, and the parties that have signed the Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 11th day of January, 2013.

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Arizona Corporation Commission
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SUSAN BITTER-SMITH
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IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. E-01933A-12-0291

(RATE DESIGN)

DIRECT

TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 11, 2012

TABLE OF CONTENTS

EXHIBITS

EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291

Mr. Solganick's testimony reviews and analyzes Tucson Electric Power Company's ("Company") jurisdictional allocation, class cost of service study ("CCOSS") and the various rate design proposals of the Company. Mr. Solganick also previously filed testimony on the Company's Lost Fixed Cost Recovery proposal on December 21, 2012.

Mr. Solganick's testimony presents Staff's recommendations based on a review of the Company's application and responses to Staff's and other parties' data requests.

Staff recommends that the Company's jurisdictional allocation is appropriate to use to develop the CCOSS and that the CCOSS can be used as a general guideline for the relative positions of the six customer/rate classes. Mr. Solganick's testimony also describes the economic, social, historical and other factors that may affect customers and be the basis of the Commission's determination of the allocation of an increase in revenue.

Staff recommends that the Company's proposals to consolidate and redesign its rates be modified after full analysis of the impacts on customers. Mr. Solganick recommends that the residential rates have a common customer charge and an additional block be added to the standard residential rate. For non-residential rates Mr. Solganick's analysis highlights the impact of the Company's proposal to increase the customer charge and add the charge to rates not presently including the customer charge (municipal and water pumping customers).

Staff recommends that the Company's proposals for a 100% demand ratchet, partial service requirements and a PPFAC that includes all energy costs be rejected due to the other wide ranging changes that may result from this case and the customer education needed.

Staff recommends that the Company's proposal for an extended summer On-Peak period within its Time of Use rates be replaced by an On-Peak period not to exceed five hours in order to encourage greater participation by residential and non-residential customers. Mr. Solganick recommends that a customer education program be developed for time of use rates and that a 12 month no risk test period be available to residential customers.

Staff recommends that the Company's lifeline proposal be modified to retain the level of support and to minimize the impact on certain customer subclasses due to the change in structure proposed by the Company.

Staff recommends that the tariff provision covering non-residential deposits be changed to require that deposits be analyzed after 24 months and if the customer's payment performance over the past 12 months is satisfactory that the deposit be returned.

Staff recommends that a door hanger fee proposed by the Company not be approved.

Staff recommends that the Company plan and perform research to support its rate design efforts.

Staff recommends that the final rate design be developed through a cooperative process among the parties.

I. INTRODUCTION

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

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

Q. Please summarize your qualifications and experience.

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning submetering and billing. I also previously served on two New Jersey Zoning Boards of Adjustment as Chairman and member and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 35 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have delivered expert testimony in utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand side management, capacity and system planning, and regulatory issues.

I have also led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects focused on the marketing, sale and delivery of retail energy, energy related products and services, and support services provided to utilities and retailers.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and have advised the Board of Directors of a public power utility consortium. For a period of four years I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and the Public Utilities Commission of Ohio. I also provided (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric and gas rate cases.

I have also been engaged to review utility performance before, during and after outages resulting from major storms including Hurricane Ike and the two 2011 storms that affected New Jersey.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998, I was a Managing Consultant for AT&T Solutions. From 1990 to 1994, I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held progressively increasing positions of responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice and implementation in both New Jersey and Pennsylvania.

Q. **Have you previously submitted testimony in regulatory proceedings?**

A. Yes. In this proceeding I submitted testimony in regard to Lost Fixed Cost Recovery on December 21, 2012.

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

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission

- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

II. DIRECT TESTIMONY

Q. For whom are you appearing in this proceeding?

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

Q. What is the purpose of your testimony?

A. My testimony analyzes Tucson Electric Power Company's ("Company") jurisdictional and class cost of service studies ("CCOSS") and the Company's proposed rate design. I recommend changes to the proposed rate design, time of use periods, the lifeline rates and various tariff changes.

Based on my review of the Company's application, supporting testimony, and responses to data requests, I make the following recommendations:

- The Commission should direct the Company to retain its existing blocks and to revise its proposed Residential rate design by adding an additional block.
- The Commission should direct the Company to revise its general service rate design as proposed including adjusting for the impacts on lower usage customers.
- The Commission should direct the Company to revise its Time of Use rate design as proposed including changing the proposed Summer period to encourage greater participation.

- The Commission should direct the Company to revise its lifeline (low-income and medical) rate design as proposed to continue the existing level of benefits, adjusting for the impacts on lower usage customers and encouraging conservation and consolidate the lifeline rates within the residential rates.
- The Commission should reject the implementation of proposed changes to Partial Requirements Service, the PPFAC and the definition of demand ratchet at this time due to breadth of other rate design changes and needed customer education.
- The Commission should direct the Company to revise its deposit policy for general service customers.
- The Commission should revise the Company's proposed miscellaneous service charge charges.
- The Commission should not adopt the door hanger fee proposed by the Company.
- The Commission should direct the Company to plan and perform customer and rate research.

Jurisdictional Allocation

Q. Why is jurisdictional allocation important?

A. The Company provides services to a number of entities commonly called sale for resale. The Federal Energy Regulatory Commission ("FERC") regulates wholesale transactions. In developing its revenue requirements and before performing any allocation of those requirements among retail rate classes, the costs (capital and expenses) and revenues from the wholesale customers must be removed or excluded from the jurisdictional revenue requirements process.

Q. Are there differences between the Company's jurisdictional allocation and the allocation within the CCOSS?

A. Yes. The most significant difference is the use of a 4CP (four coincident peaks for June, July, August and September)[1] allocator for production plant and related items as compared to the use of an Average and Peaks (A&P) demand allocator[2] within the CCOSS.

Q. Is the application of the 4CP method appropriate?

A. The FERC has used a three part methodology[3] to determine if a production allocator should focus on a season or the entire year. I performed this test for the years 2009 through 2011 based on information provided by the Company.[4] Based on this methodology, the use of a 4CP allocator at this level is appropriate as compared to a 12CP allocator.

Q. Is the allocator difference between retail and wholesale jurisdictions appropriate?

A. The FERC has required the use of the 4CP allocator[5] and the Company has complied with this requirement. The Company's position is appropriate because it is responding to two different regulatory bodies.

Q. Did you review other aspects of the jurisdictional allocation?

A. I performed a review of the allocations, developed and reviewed the answers to Staff Data Requests and discussed items as needed with the Company to understand certain aspects of the jurisdictional allocation.

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[1] Jones Direct 13:8
[2] Jones Direct 18:11
[3] FERC Docket Nos. EL05-19-002 and ER05-168-001, paragraph 76
[4] DoD 1.03 Revised
[5] TEP Response to STF 1.020

Q. Is the Company's jurisdictional allocation appropriate for its use to develop the CCOSS?

A. Yes it is.

Class Cost of Service

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

A. The Company provided an updated CCOSS based on the Test Year (twelve month period ended December 31, 2011).[6] This schedule provides the individual class returns for the Company's six major customer classes. No subclass or rate class information was presented.

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

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

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

A. Because customer classes use the utility's system on an interrelated or shared basis, regulators have historically used a fully allocated cost of service study as a guideline to allocate revenue among classes. Additionally, when determining revenue allocation, regulators have a responsibility to consider not only the utility's financial condition and requirements, but also economic, social, historical and other factors that may affect customers.

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[6] TEP Filing Schedule G revised on 10/5/12

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

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

Q. Did the Company adjust or normalize its revenues?

A. The Company used a 2011 Test Year and then adjusted it to reflect more normal or appropriate (from the Company's viewpoint) conditions. The Company made revenue adjustments for weather normalization and customer annualization.[7]

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

A. Yes. The CCOSS was provided as Schedules G-1 through 7. I performed a review of the allocations, developed and reviewed the answers to Data Requests by Staff and other parties and conducted an informal technical conference with the Company to understand certain aspects of the CCOSS.

Q. Is the application of A&P allocator appropriate within the CCOSS?

A. The Company expects to make substantial environmental investments to retain its coal generation capability, which indicates a focus on energy costs.[8] Additionally, the Company is forecasting the need for peaking investments.[9] This combination of expected

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[7] Jones Direct 6:14 and 10:1
[8] DeConcini Direct 29:21
[9] 2012 TEP IRP pages 20, 28, 30

investments for both energy and peak supports the use of an A&P methodology for the allocation of generation as opposed to either a peak or energy focused allocator.

Q. Does the CCOSS provide unit cost information to support rate design?

A. The Company provided Schedule G-6-1 labeled Revenues and Unit Cost. After my initial review I was concerned that the "unit costs" shown for residential customer costs were only $5.11. The Company's response to DoD 2.2 indicated "There is not a return component included in Schedule 6 for Unit Cost". Staff then asked for unit cost data including a return component at the overall rate of return. The Company's response was provided and the inclusion of the return component has raised customer related costs to $6.33.[10]

Q. How did the Company allocate income taxes?

A. The Company indicated that it allocated income taxes to reflect an equalized return on plant.[11] The calculation of income taxes on class net income would provide the same general positioning between classes but result in larger differences among classes.

Q. Did the Company perform a loss study for use in the CCOSS?

A. The Company indicated that it had not completed an engineering study on line losses over the last two rate cases.[12] Further, the Company indicated that "losses" also includes an allocation of variance amounts resulting from load research data.[13]

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[10] TEP Response to STF 21.1
[11] TEP Response to AECC 3.5 a
[12] TEP Response to STF 1.032 and AECC 3.1 c
[13] TEP Response to AECC 6.1 b (i)

Q. Is the Company's CCOSS appropriate for its use as a guideline to develop a revenue allocation proposal?

A. The results of the CCOSS should be used as a general guideline for the relative positions of the six cost of service classes. The items I have summarized above should cause some concern about the use of precise results from the CCOSS.

Q. What are the relative positions of the various classes?

A. As a high level indicator I use the Rate of Return on Rate Base as shown in Schedule G-1 (line 33). Compared to the overall return for the Company at 1.90%, the Small General Service class at 20.43% is providing an above average return, the Residential Service class at -0.40% and Large General Service class at 0.52% are providing a return below the average and the Large Light & Power class at -9.02%, Mining class at -12.98% and Lighting class at -11.43% are providing returns well below the average.

Revenue Allocation

Q. What non-cost considerations should the Commission consider?

A. The Commission should consider the relative positions of the classes along with the qualitative issues such as economic conditions for consumers, the business climate and past practices when deciding what portion of a revenue increase is allocated to each class. Also the size of the classes limits how much the Commission can move a class at the conclusion of any single rate case. For example, the Large General Service, Large Light & Power, Mining and Lighting classes together are still smaller than the Small General Service class. The Residential class is more than 50% larger than the Small General Service class.[14]

[14] TEP Schedule G-1 line 20 Total Electric Revenue From Sales

Q. Based upon the CCOSS results what revenue allocation concept do you recommend?

A. In concept the revenue allocation should assign a larger percentage increase (compared to the overall increase allowed for the Company) to classes earning less than the system average and a smaller percentage increase to classes that provide returns greater than the system average return.

Further, all classes should earn a positive return. This goal may not be able to be achieved within this case as the required increase may be judged too high in regard to the factors stated above, but it is a long-term goal that should be considered by the Commission.

Rate Design

Q. What underlying principles do you use for rate design?

A. For residential and small general service customers, I lean towards simplicity where possible. This would include a limited number of rate schedules and riders. I recognize that one rate schedule does not fit all customers and that schedules that encourage limiting or shifting peak consumption have real value both for customers, for system planners and longer term cost reduction.

For delivery (distribution) rates, I recommend gradually shifting from volumetric to customer and demand charges as supported by cost of service principles. This recognizes that delivery services are not generally based on volumetric (energy) parameters but vary based on the number of customers and their demand.

Q. Does the implementation of advanced metering infrastructure ("AMI") have a rate design impact?

A. Yes. In recognition of the penetration of automated meter reading ("AMR")[15] and the potential implementation of AMI, I recommend that the customer charge for similar customers in the same class but on different rate schedules should be the same. This recognizes that costs are the same for AMI regardless of whether the customer chooses a standard rate or a time of use ("TOU") rate. Smart meters have the capability to report consumption by interval and then the usage by periods is determined by data analysis rather than by meter readings. Thus the same meter and software can be used to provide meter reading for most rate forms at approximately equal cost.

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

A. The Company is proposing to make a wide variety of changes to its existing rates along with the addition of a rate for electric vehicles. The Company's rate design objectives are to consolidate, simplify, and modernize these rates for several key reasons including that many rates are only nominally different and the sheer number of rates can create unnecessary confusion for customers.[16] Additionally, there are rates that are frozen (no longer available to new customers) that require time and costs to maintain and these rates are considered by the Company to be below the cost of providing service.[17] The Company also wishes to better align the Commission's policies with the Company's need for fixed cost recovery.[18]

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[15] TEP Response to VSI 3.02
[16] Jones Direct 22:7
[17] Jones Direct 24:21
[18] Jones Direct 25:7

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

A. As I understand the Company's approach, the focus was on evaluating the potential impacts on customers by developing a complete understanding of how these changes would affect revenues.[19] The Company describes its efforts to determine the appropriate level of billing determinants[20] and its efforts to approach a revenue neutral impact on each class[21].

Q. Is this focus on revenue impact sufficient to support a wide range of rate design changes?

A. Evaluating the revenue impact is not the only concern when rate design is substantially changed. There are impacts on the customers' behavior and operations that should be considered during the rate design process to minimize unintended consequences. While the following list is not exhaustive it includes a range of sources of information about customers that should be considered.

- Customer Alternatives
  - Competitive Fuel Forecasting[22]
  - End Use Forecasting[23]
  - Cost of Load Shifting for TOU[24]
- Customer Information
  - Formal Commercial & Industrial Survey Process[25]
  - Appliance Saturation Study[26]

[19] Jones Direct 25:16
[20] Jones Direct 25:20
[21] Jones Direct 26:4
[22] TEP Response to STF 1.008
[23] TEP Response to STF 1.006
[24] TEP Response to STF 1.079
[25] TEP Response to STF 1.005
[26] TEP Response to STF 1.007

  - Consumption versus Income[27]
- Rate Studies
  - Non-Coincident Peak ("NCP") Data[28]
  - System Losses[29]
  - Marginal Cost[30]
  - Seasonal Energy[31]

Q. Did the Company perform any of the above studies or have such information?

A. In response to Staff data requests the Company indicated that these items were not readily available, or were not forecast for future years (2012 -2014), or backcast information was not available, or only limited information was available. [The above footnotes provide references.]

Q. Are these items essential to accomplish the scope of the rate design envisioned by the Company?

A. Having all of the items is not essential but each item provides information about customer options and potential reactions to a new or modified rate. The lack of this information increases the possibility that some important aspect will be overlooked or cannot be readily evaluated by all parties.

[27] TEP Response to STF 1.041
[28] TEP Response to STF 1.031
[29] TEP Response to STF 1.032, 1.077, AECC 3.1
[30] TEP Response to STF 1.037
[31] TEP Response to STF 1.076

Q. Should the Company's proposal to make rate design changes be rejected?

A. No, but some items should be delayed or modified until supporting information is available. Also, the sheer magnitude of the changes should be gaged and the range of proposed changes placed into perspective and chosen carefully.

Q. Is the Company proposing any overall or wide reaching rate design changes?

A. Yes, the Company is focusing on decreasing the proportion of revenue that is collected from energy charges.[32] This leads to the Company's proposal to increase the monthly Customer Charge.[33]

Q. What rate changes does the Company propose for the non-TOU Residential Service subclass?

A. The Company is requesting an increase in the customer charge from $7.00 to $12.00 .[34]

The Company is also requesting the elimination of the third tier (over 3,500 kWh) for Rate R-01[35]; the shift of all Rate R-02F load to Rate R-01[36]; the elimination of Rate R-201 AF and moving those customers to Rate R-201 AN[37].

Q. What rate changes does the Company propose for the TOU Residential Service subclass?

A. The Company is requesting an increase in the customer charge from $8.00 to $15.00 for TOU customers.[38]

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[32] Jones Direct 28:10
[33] Jones Direct 28:4
[34] Jones Direct 33:14
[35] Jones Direct 36:12
[36] Jones Direct 36:13
[37] Jones Direct 36:14

The Company also is requesting the creation of a new TOU Rate R-80 that would shift customers presently served by Rates R-21F, 70F, 70NB, 70NC and 70ND.[39]

Similarly the Company is requesting the consolidation into TOU Rate R-201BN of customers presently served by Rates R-201BF, 201CF and 201CN.[40]

Q. Do you support the changes to the standard residential rate?A. I suggest the following modifications of the Company's proposal:

- The existing rate design including the first tier (up to 500 kWh) and the upper tier (over 3,500 kWh) should be retained.
- A new tier for the Rate R-01 at 1,000 kWh should be developed to offer a breakpoint that includes approximately 58% of all summer bills and over 80% of winter bills.[41]. The Rate R-02 usage can then be combined into the Rate R-01, as this new block would decrease the impact on some water-heating customers. Ideally customer load research by strata and unit costs would help develop the relationships between the tiers but the Company has indicated that it does not have this type of load research.[42]
- The existing inverted rate structure should be retained for the Rate R-01.

Q. Are residential customer charges interrelated?

A. Yes. The customer charge for the TOU rate should equal the customer charge for non-TOU rates to reflect the eventual implementation of advanced meters.

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[38] Jones Direct 33:14
[39] Jones Direct 36:15
[40] Jones Direct 36:20
[41] TEP worksheet – R-01 BF update for Howard 10-24-12.xls
[42] Company email dated October 19, 2012

Q. What are the residential customer costs?

A. The Company's information shows that direct customer costs are $6.33.[43] This amount includes meters, billing and collection meter reading costs and the service.[44] The Company has indicated that it does not use either a minimum sized system or zero intercept methodology to allocate portions of the distribution system (such as poles, wires, transformers) to the customer component.

Q. Please discuss the Company's basis for the Residential Customer Charge?

A. The Company is requesting a Customer Charge of $12 per month, which it characterizes as 22% of the $55.00 (now $68.39[45]) of customer and demand charges identified by the CCOSS. It is inappropriate to consider in the basis for the monthly Customer Charge shared costs such as production and transmission that do vary with the demand the customer places on the system and those costs should be collected in a charge that varies with usage (absent a demand charge). Even the costs of Demand Distribution that are equivalent to $10.69[46] would be excessive as that value includes facilities that are below 138,000 V.[47]

Q. What increase in the Residential Customer Charge do you propose?

A. Without information provided by a minimum sized system or zero intercept analysis, I recommend a Residential Customer Charge of $10.00,subject to review of customer impact at various usage levels. This provides coverage for direct customer costs and a portion of distribution costs.

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[43] TEP Response to STF 21.1
[44] Schedule G, Functionalization_RES Q44 Account 369 Services
[45] TEP Response to STF 21.1
[46] TEP Response to STF 21.1
[47] TEP Response to AECC 11.4

Q. What is the Company's opt-out option for those customers that do not want an AMR meter that uses radio frequency for meter reading?

A. The Company has proposed to add language to the Rate R-01 to charge the Special Meter Reading fee each month and a one-time Meter Change-out fee.[48] The charges proposed by the Company are both $20.00, an increase from the existing $13.50.[49]

Q. Is the Company's Opt-Out proposal appropriate?

A. In this situation, a customer is requesting non-standard service and should pay for the incremental cost of providing service, otherwise all other customers have to pay for the additional work requested by a single customer. However, the Company's proposal assumes that each customer served in this manner is separate and that no economies of scale exist even though this customer's request may be able to be scheduled with other work.

Q. What process do you propose for Opt-Out customers?

A. I recommend that the additional meter reading services requested by Opt-Out customers be priced to encourage the Company to productively handle Opt-Out service. For example, the Company's tariff describes an existing process for customers that require special meter reading.[50] One productivity measure that could be encouraged would be the use of meter reading by customers that would support a lower monthly charge. As described in the tariff, the Company would read the meter at least once every six months. Under either type of meter reading the Company still has costs for special data entry.

[48] Jones Direct 38:11 and Exhibit CAJ-11
[49] Exhibit CAJ-9 - Tariff Original Sheet 801
[50] TEP Tariff Section 10 Meter Reading

Q. What charges do you propose for Opt-Out services?

A. I recommend that monthly readings made by the Opt-Out customer should be priced at 25% of the Special Meter Reading fee. Readings made by the Company for the Opt-Out service should be priced at 50% of the Special Meter Reading fee. The Company should be allowed to vary the monthly period by up to plus or minus five days (rather than a quasi meter reading cycle) to allow for scheduling efficiency. If the customer already has an analog meter in place, the one-time Meter Charge-out fee should not be assessed if the existing meter can be used.

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

A. Some customers using this rate may have characteristics similar to a residential customer and this rate also does not include a demand charge. The Company is proposing to increase the customer charge to $18.00 from $8.00. Also the municipal customers served under Rate PS-40 have no customer charge at present. The proposed increase is too large when placed in this prospective and the impact will be disproportionate on low usage customers. The unit cost information in Schedule G-6-1 indicates that customer costs for the Small General Service Class are $18.25.[51] Based on this information the Company's proposed Customer Charge is numerically appropriate if the Company receives its fully requested increase. As this outcome is unlikely, the Small General Service Customer Charge should be reduced to eliminate the disproportionate impact.

Q. Is the Company's proposed consolidation of Rate PS-40 into GS-10 appropriate?

A. The Company has recognized the impact of its proposal to eliminate Rate PS-40 (Municipal Service) and proposes a mechanism (a 16.5% discount) to shield municipal

[51] TEP Response to STF 21.1

customers from extraordinary impact. This "rate blocker" is a concept used in this type of situation. However, the consolidation would now subject these accounts to a proposed $18.00 customer charge when presently there is no customer charge.

The Company has calculated impacts of 22% (summer) and 17% (winter) for usage at 10,000 through 20,000 kWh.[52] However, in summer almost 75% and in winter 79.5% of all bills are lower than 10,000 kWh.[53] Calculating the impacts for the governmental entities at more realistic levels shows significant impacts such as over a one third of the bills will have increases of 40%, and 15% of the bills will have increases of 200%. While the 200% increase amounts to essentially the proposed new Customer Charge of $18.00, this impact should have been known and/or disclosed. The proposed Customer Charge should be reduced to lower the dollar impact for lower usage customers.

Q. What rate changes does the Company propose for the Water Pumping rates?

A. The Company proposes to consolidate water-pumping rates (GS-31 and PS-43) into a single rate schedule GS-43 that includes an interruptible option. GS-31 presently serves agricultural customers. At present GS-31 applies to only pumping load that must be interruptible, while PS-43 applies to water utilities. As proposed by the Company the tariff language for the new GS-43 would not apply to agricultural pumping. The Company did confirm that this should to be corrected.[54] Schedule H-4[55] also must be updated as the calculation of the Proposed Rate for "C-31" Interruptible Agricultural Pumping does not match the value for "PS-45" Interruptible Municipal Pumping by the value of the $18 customer charge.

[52] Schedule H-4 pages 24 and 25
[53] Schedule H-5 pages 28 and 29
[54] Email dated October 23, 2012
[55] Schedule H-4 Page 26

Q. Are the changes proposed for the water-pumping rate appropriate?

A. I am concerned that the consolidation has not been completely analyzed. The Company has calculated impacts of 22% (summer) and 12% (winter) for usage at 16,000 through 21,000 kWh for PS-43 customers choosing firm service.[56] However, in summer 60%, and in winter 69%, of all bills are lower than 10,000 kWh.[57] Calculating the impacts for the municipal pumping customers at more realistic levels shows significant impacts such as one quarter of the bills will have increases of 57% and 13% of the bills will have increases of 200%. While the 200% increase amounts to essentially the proposed new Customer Charge of $18, this impact should have been known and/or disclosed. The proposed Customer Charge should be reduced to lower the dollar impact for lower usage customers.

Q. Is the Company's change to the demand ratchet appropriate?

A. The change to a 100% demand ratchet is not appropriate at this time. The Company is embarking on a series of rate consolidations that will require individual customers to analyze the impact and then if needed make changes in their operations. Changing the demand ratchet will at best confuse those customers' demand history and make the customers' analysis more difficult. Therefore, I recommend that the Commission not implement the 100% demand ratchet at this time. In preparation for this future change the Company should consider how to accumulate and make demand ratchet data available to customers.

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[56] Schedule H-4 page 25

[57] Schedule H-5 pages 28 and 29

Q. What rate changes does the Company propose for the Large General Service and Large Light & Power Rates?

A. The Company is requesting the consolidation into Rate LGS-85N of customers presently served by Rates LGS-85F and LGS-85AF.[58] The Company also is requesting the consolidation into Rate LLP-90N of customers presently served by Rates LLP-90F and LLP-90AF.[59]

The Company is proposing to set the demand ratchet at 100% and eliminating the 50% or 66% levels.[60]

Q. Do you support the changes to the Large General Service and Large Light & Power Rates?

A. I support the consolidation of the rates with the proviso that the impact be analyzed at a finer level than the average customer as shown in Schedules H-1, H-2-2 and H-4. The Company's response to STF 1.042, 1.043, 1.044 and 1.045 demonstrate that the analysis can be made at a finer (more customer focused) level and these analyses are now in the record for those customers to analyze. Specifically, the Company's analysis should consider the impact by load factor and overall usage. Additionally, as I stated above the change to the 100% demand ratchet should not be implemented in this case.

Q. How is the Company proposing to change its TOU rates?

A. The Company is proposing to reduce the number of TOU rates significantly. The Company also has highlighted that there has been limited participation in TOU rates and that reducing complexity will increase participation and help reduce peak demand and

[58] Jones Direct 37:4
[59] Jones Direct 37:7
[60] Jones Direct 40:6

over the long term reduce the costs of rate administration.[61] The Company is proposing a summer On-Peak period of 10 AM to 9 PM and two Winter On-Peak periods of 6 AM to 10 AM and 5 PM to 9 PM.

Q. Have you mapped out the Company's proposed changes to the TOU rate periods?

A. To visualize the changes proposed I have generated Exhibit HS-4.

Q. Do you support the changes to the residential TOU rate?

A. Yes and no. I agree with the Company proposal to have no On-Peak periods on the weekend and to eliminate Shoulder periods as confusing to customers.

As detailed above I recommend a residential customer charge that is equal to the R-01 charge.

Although the Company has provided its rationale for the development of system wide TOU On-Peak periods, I have concerns about the imposition of the broad hours proposed for residential customers.

Q. What are your concerns about the Company's TOU proposal?

A. Only the R-21 customers (approximately 2,400) are presently subject to a Summer On-Peak period as long (11 hours) as that proposed by the Company and similar periods in the winter. It is unclear whether these customers have adapted to the frozen Rate R-21 or they have stayed there due to inertia or the perceived frozen lower rate.

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61 Jones Direct 41:23

The Rate R-70 and R-201 customers (approximately 1,400 and 4,200 respectively) are presently subject to a significantly shorter On-Peak period (5 hours in the summer).

Q. What parameters do you recommend to encourage customers to adopt TOU rates?

A. In light of this situation and the limited information available[62] about existing residential TOU customers including the costs they may incur to deal with broad On-Peak periods, I recommend that:

- The residential Summer On-Peak period should be set at a maximum period of 6 hours. Staff suggests 2:00 PM to 8:00 PM.
- The Company should offer existing Rate R-01 and R-201AN customers the option to try the TOU rate with a six-month "money back" trial that allows them to return and recover any costs above the corresponding R-01 or R-201AN rate. This concept is included in Rates R-70F, R-201BF and R-201CF but has not been retained by the Company in its proposed Residential Time-of-Use rate R-80.
- To assist the customer to make the transition to TOU rates, the Company should provide a tool for the customer to perform a TOU analysis as part of a TOU customer education program.
- The Company should develop a customer education program to retain the existing residential TOU customers.
- The Company should develop a research program to understand the benefits of TOU rates for the customer and the Company, including potential capacity and energy savings.

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[62] TEP Response to STF 1.079, STF 1.083 and STF 1.003

These recommendations are made to increase participation, understand why customers choose and stay on the TOU rate and measure the impact on energy costs and peak demand.

Q. Does the Company's proposal provide for a Critical Peak rate?

A. No.

Q. What are the advantags of a Critical Peak Rate?

A. A critical peak rate can offer advantages to the Company and customers by targeting periods of high energy costs and/or capacity needs. I recommend that the Commission order the Company to file a critical peak rate proposal within six months of the effective date of this case including a plan to implement the rate before summer 2014.

Q. The Company has proposed an Electric Vehicle rate, do you have any comments?

A. The Company has proposed an Electric Vehicle rate to be included as an option on the two residential TOU rates.[63] Based on my review it seems to be an inconsistency about the level of the discount as the tariff sheets (102-1 and 104-1) and the Company's response to STF 1.068 show a discount of 5%, while Table 5 of Mr. DesLauriers' testimony[64] shows a discount of 10% off the Off-Peak (low voltage) rate.

Q. Has the Commission previously addressed this issue?

A. Yes. The Commission has reviewed this issue in Decision No. 72582.[65] This decision supports the concept of a "whole house" rate, as does the Company's version, thus

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[63] Jones Direct 50:14

[64] DesLauriers Direct 35:6

[65] *In the Matter of the Application of Arizona Public Service Company for Approval of Proposed Electric Vehicle Demonstration Project*, Docket No. E-01345A-10-0123

eliminating the need for additional metering and billing. The decision goes further and sets up a "Super Off-Peak" time period during weekdays to encourage cost effective charging from both the customer's and the Company's perspective. I recommend that the Company modify its proposal to conform to the decision and resolve the difference between the 5% and 10% discounts proposed.

Q. Do you support the changes to the non-residential TOU rate?

A. Yes. The Company is proposing a summer On-Peak period of 10 AM to 9 PM and two Winter On-Peak periods of 6 AM to 10 AM and 5 PM to 9 PM. I agree with the Company proposal to have no On-Peak periods on the weekend and to eliminate Shoulder periods as confusing to customers.

As shown on Exhibit HS-4 the Company's proposal for the new TOU is at variance with the existing summer TOU periods even when the shoulder periods are included. The Company does not have a formal process for obtaining input from its C&I customers.[66] Absent supporting information, extending the TOU period could reduce participation rather than increase the desired savings in energy costs and peak load reduction.

Q. What parameters do you recommend to encourage non-residential customers to adopt TOU rates?

A. I recommend that:

- The consolidation of non-residential TOU rates should be accepted.
- The non-residential Summer On-Peak period should be set at a maximum of 5 hours. The Company should reanalyze its data and customer experience to determine the On-Peak period subject to input from the parties. Although they

[66] TEP Response to STF 1.005

could be the same, there is no compelling reason that the non-residential and residential TOU periods need to be the same if participation, customer experience or feedback is different.

- The Company should develop a customer education program to retain the existing non-residential TOU customers and encourage new TOU customers. This may require training for its C&I representatives and/or the engagement of outside consultants.
- The Company should develop a research program to understand the operational impact of TOU rates on C&I customers and the Company, including potential capacity and energy savings.

These recommendations are made to increase participation, understand why customers choose and stay on the TOU rates and measure the impact on energy costs and peak demand.

Q. Why do you recommend Summer On-Peak time periods that do not match the period suggested by the Company?

A. The Company's work focused on its costs, however the goal is to obtain savings on energy costs and long-term peak load demand reductions. The Company's proposed On-Peak time period may fit the Company's operations but it may not encourage customers to shift to the new rates and may reduce the existing participation rates.

Q. Will a change in the On-Peak period change the rates charged to customers?

A. Yes, and only the Company has access to the billing determinants for different periods to calculate rates for the shorter period.

Q. Why have you not recommended changes in the Company's proposed Winter On-Peak period?

A. The Company's proposal is substantially the same as the existing TOU rates and the split periods offer customers multiple opportunities to shift load.

Q. Do you agree with the conceptual rate changes that the Company has proposed for the Lighting Service class?

A. Yes.

Q. Do you support the proposed changes to the Partial Requirements Service Rates?

A. No. There are no customers on these rates at this time[67] so there is no high level of urgency at this time. The Company's proposal needs to be further examined, as significant basic items such as the definition of Backup/Standby Service and Supplemental Service are not in the tariff.[68]

Considering the number of rate changes that will need to be implemented if the Commission approves them, adding changes to PRS Service will only increase the impact on the Company. As there is no revenue impact this change could be handled after the completion of this case.

[67] TEP Response to STF 1.065
[68] Email from TEP dated October 8, 2012

Q. Do you support the Company's proposed change to the PPFAC that recovers all fuel and purchased power costs through the PPFAC and develops multiple PPFAC rates to differentiate between time periods, voltage levels and interruptible service?

A. The Company has described the conceptual basis for this change in its testimony. At this time I am concerned that this overarching change that would affect every one of the Company's rates would increase the confusion level during a significant rate change. Therefore I recommend that the concept be revisited in the future.

Q. Please describe the Company's Lifeline proposal.

A. The Company is proposing to simplify and consolidate the existing Lifeline options while also reflecting movement towards the costs to serve these customers.[69]

Q. Please summarize the existing Lifeline program.

A. There are four Lifeline options that can apply to the different residential rates and some of these options are frozen.[70] The Customer Charge is discounted and a further discount is applied on a sliding scale that decreases as consumption increases.[71] Lifeline customers are exempt from paying the PPFAC and DSM charges.[72]

Q. What is the overall value of the Lifeline program?

A. The Company's testimony indicates that the combination of all these "concessions" totaled over $2.2 million during the test year for approximately 23,000 customers.[73]

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[69] Jones Direct 69:16
[70] Jones Direct 69:23
[71] Jones Direct 70:4
[72] Jones Direct 70:11
[73] Jones Direct 70:16

The Company has detailed the direct program costs as $2.512 million in discounts, $1.759 million in fuel cost related subsidies and $0.285 of avoided DSM related charges for a total of $4.556 million.[74]

The Company has indicated that it increased the subsidy to $2,605,960 in its Test Year calculations, which is a 14% increase to reflect the 14% increase in residential rates.[75]

Q. What is the Company's Lifeline proposal?

A. Lifeline customers now receiving a sliding scale discount of from 0 to 35% (Rates R-04, R-05 and R-08) will be moved to a new rate with a 25% discount on all volumetric charges. Existing Rate R-06 customers now receiving a flat $8.00 discount (approximately 70% of Lifeline customers) will receive a flat $10.00 per month discount.[76]

Lifeline customers in the "senior" and "medical" categories would receive the same discount as other Lifeline customers who will now be subject to a limit of income below 150% of the federal defined poverty level.[77]

Q. Is the Company proposing other changes to Lifeline rates?

A. Yes. All Lifeline customers will no longer be exempt from the PPFAC and the DSM charges.[78] The Company has indicated that the proposed discount applied to Lifeline

[74] TEP Response to STF 1.093
[75] TEP Response to STF 1.094
[76] Jones Direct 71:15
[77] Jones Direct 72:14
[78] Jones Direct 71:20

customers would apply to PPFAC and DSM charges and the net lower rates would flow through to the annual under recovery within the true –up calculation.[79]

The Company is also proposing to eliminate making the Lifeline rate mobile and requiring customers to re-qualify if they move and also subject to re-qualification annually at the Company's request.[80]

Q. Have you reviewed the Company's proposal to revise the Lifeline programs?

A. Yes and I support the concept of the Company's recommendation to simplify the structure of the program and reduce potential confusion upon entry into and exit from the program.

To highlight the total value of the programs provided by other customers, the Company has proposed a simpler/clearer method that would allow a customer to take service on an existing residential rate schedule and then have all of the benefits be provided through an embedded rate rider. This concept is appropriate.

Q. The Company has proposed applying the PPFAC and DSMS charges to the Lifeline rate schedules[81], do you agree with this proposal?

A. Yes. The Company's argument to include the PPFAC and DSMS adjustors for these customers is supported by concepts of rate clarity and simplicity.

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[79] Email from TEP dated October 23, 2012
[80] Jones Direct 71:4
[81] Jones Direct 71:20

Q. The Company has proposed to cancel a customer's Lifeline rate if the customer moves and require reapplication. Is this appropriate?

A. The Company has stated that a change in location can indicate a change in status and this would be an optimal time to verify if a customer still qualifies for a discounted rate.[82] The Company already requires annual requalification for the program.[83] I recommend that the Company's proposal to re-qualify customers upon a move be rejected as there is an annual process in place and a secondary requalification will probably increase costs with little, if any, benefit.

Q. Is the Company's Lifeline proposal appropriate when viewed on a customer impact basis?

A. No. The Company provided estimates of its proposed rates to current rates.[84] Non-Lifeline customers served under the various residential rates generally will experience consistent increases. Almost all of the Lifeline customers will experience percentage increases significantly higher than other customers. The following table summarizes this situation.

	% Change to Total Bill				
Rate	Std.	04	05	08	06
R-01	14.1	24.8	9.7	39.7	14.4
R-21F TOU	27.8	49.3	31.3	67.4	38.6
R-70F TOU	15.1	39.0	22.2	56.0	27.8
R-201AF	11.3		29.1	63.6	36.6
R-201BF	11.8		24.7		30.8

[82] TEP Response to STF 1.096
[83] TEP Response to STF 1.097
[84] TEP Exhibit CAJ-1 Corrected 8-17-12

This situation is at variance with the Company's response that it has increased the Lifeline amounts by 14%. When that same exhibit is examined for total dollar impact the Rate R-08-XX series have large dollar increases compared to the other Lifeline and non-Lifeline rates.

Q. How do you recommend that the proposed Lifeline rates be revised?

A. In its discovery response the Company indicated that the subsidy had been increased by 14% similar to reflect the 14% increase in residential rates. At present it is appropriate to maintain the existing "benefit" of the Lifeline rates at the $ 4.6 million dollar level plus an offset for any increase granted.

When the final rates are determined the Company should prepare its documentation to ensure all parties that the Lifeline "benefit" has not been significantly changed.

Rate R-08-XX should be adjusted to reduce the predicted impact. Also the impact at various usage levels should be examined to minimize the impact at lower usage. The Company's Schedule H-4 (pages 1 and 2) demonstrates that the Company has the tools available to make that analysis. One method to reduce the impact would be to retain the declining discount concept now used for the Lifeline rates.

Q. The Company is proposing a number of miscellaneous tariff changes. Have you reviewed those proposals?

A. Yes. The Company proposes to move the fees[85] to one location called "Statement of Charges" to make them easier for customers to locate.[86] I support that proposal.

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[85] Exhibit CAJ-9
[86] Jones Direct 74:20

Q. Have you examined the proposed miscellaneous charges?

A. Yes. In response to a Staff data request, the Company provided the background information to support the revised fees.[87] I am concerned that the Meter Test and Service Establishment fees are excessive. My review of these rates indicates that a 60.6% Labor Overhead was added in the calculation of this rate. Other fees do not use any Labor Overhead. The calculations should be adjusted to remove the Labor Overhead.

Q. Do you suggest any other changes to the Company's tariffs?

A. Yes. The Company's present tariffs allow the Company to require and retain a deposit to guarantee the payment of all bills until service is discontinued and all bills have been paid. While there is a procedure to return the deposit for residential customers it appears that the Company can retain the deposit from a non-residential customer until service is discontinued.

In contrast the tariff for Arizona Public Service ("APS") provides that the non-residential customers deposits will be reviewed after 24 months of service and the deposit will be returned based upon the past 12 months payment performance.

In Decision No. 73142, for UNS Gas, Inc. the Commission considered this issue and adopted provisions similar to APS' tariff as suggested by Staff.[88]

In light of the Commission's recent consideration of this issue, I recommend that the Company be ordered to change its tariff provisions for non-residential deposits consistent with Decision No. 73142.

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[87] TEP Response to STF 1.100
[88] Docket No. G-04204A-11-0158

Q. Do you also have a concern about a proposed door hanging fee?

A. Yes. The Company has added "Door Hanging Fee" to its proposed Statement of Charges among the list of items under the $20.00 Trip Charge. The Company does not currently have a door hanging fee listed on its Statement of Additional Charges.

Q. Please describe your concern regarding the door hanger issue.

A. The Company is introducing a door hanger fee when the Company places a door hanger as part of the Company's disconnection of service process. Staff does not believe that a door hanger fee should be charged by the Company to its customers who are facing possible disconnection of service. Such customers are struggling to pay their utility bill, and an additional $20 door hanger fee would just aggravate an already financially difficult situation for such customers. A door hanger is not required by Commission rules. The Commission considered this issue for UNS Gas and rejected the door hanger fee in Decision No. 73142.

Therefore, Staff recommends against adoption of the door hanger fee proposed by the Company. The Company may provide door hangers free of charge if the Company so chooses, but customers should not be charged an additional fee for a door hanger.

Q. Do you have any overall recommendations as a result of your rate design review in this case?

A. Yes. There are a number of areas where the Company has not conducted specific research other than as part of its rate design process. The Company should plan and perform research to support its ongoing rate design efforts. The Company should be required to define for the Staff a rate research plan within three months of the end of this case, complete the plan within an additional nine months and then provide the results to Staff. The plan might include:

- Reviewing or justifying the existing blocks and tiers within rate schedules in light of recent load research, appliance saturation, new uses such as heat pump water heaters, energy efficient computers, televisions and the penetration of energy efficient appliances
- Determining if, when and how distribution (delivery) rates might shift from volumetric to demand based to eliminate the need for a decoupling mechanism
- Performing a loss study to support cost of service efforts
- Enhancing load research to produce load strata data

Q. You have made a number of rate design recommendations that potentially interact with each other and are dependent on the final revenue increase, if any. How can the recommendations be implemented?

A. Unlike the revenue requirements process, rate design is much less linear and therefore it is less suited to having the final rates set by an adversarial process. While the parties can each argue for their rate design methodologies, once those positions are accepted or rejected (either by settlement or the Commission's decision) the Company is in the best position to use its models and customer data to develop compliance rates. Under either process all parties should have the opportunity to review the "final" rates, determine if the rate design positions were properly and accurately implemented and request alternate rates to better meet the decided positions before providing their approval. Through its technical conferences (formal and informal) and the data request process the Company has demonstrated its ability to participate in an interactive process. Hopefully, this positive behavior by all parties will take place during the settlement process or subsequent to and directed by the Commission's rate design decision.

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

A. Yes. There is always a risk that outlier customers can experience unintended consequences such as some of the conditions I have found and highlighted in my testimony. This risk is increased when customer research is limited or has not been performed.

I recommend that the Commission include a process to allow Staff to reopen the rate design portion of this case if concerns develop over rate design subsequent to the implementation of new rates. Legal counsel should develop the details of this process, including notice and hearings.

Q. Does this conclude your testimony?

A. Yes.

Present On-Peak
Present Shoulder
Weekday Only | TEP Proposed On-Peak

Time of Use Periods

Hour Ending

AM | PM

Rate Schedule	# Customers	Proposed Rate Schedule
Summer		
General Service		
GS-76N	105	GS-76N
GS-76F	814	GS-76N
Large General Service		
LGS-85N	72	LGS-85N
LGS-85AF	16	LGS-85N
LGS-85F	8	LGS-85N
LLP-90F	4	LLP-90N
LLP-90N	4	LLP-90N
LLP-90AF	2	LLP-90N
Residential		
R-21 F	2366	R-80
R-04-21F	4	R-80
R-05-21F	4	R-80
R-06-21F	25	R-80
R-08-21F	9	R-80
R-70N-B	226	R-80
R-70N-B Weekend		R-80
R-70N-C	684	R-80
R-70N-C Weekend		R-80
R-70N-D	485	R-80
R-70 F	4010	R-80
R-04-70F	6	R-80
R-05-70F	16	R-80
R-06-70	109	R-80
R-08-70	24	R-80
R-06-201B	12	R-201BN
R-06-201C		R-201BN
R-08-201B		R-201BN
R-08-201C		R-201BN
R-201BN	58	R-201BN
R-201BF	473	R-201BN
R-201CF	151	R-201BN
R-201CN	18	R-201BN

* Source for number of customers - Exhibit CAJ-1 Corrected 8-17-12 page 1 of 2

Time of Use Periods

Present On-Peak

Hour Ending

AM | PM

Rate Schedule	# Customers	Proposed Rate Schedule
Winter		
General Service		
GS-76N	105	GS-76N
GS-76F	814	GS-76N
Large General Service		
LGS-85N	72	LGS-85N
LGS-85AF	16	LGS-85N
LGS-85F	8	LGS-85N
LLP-90F	4	LLP-90N
LLP-90N	4	LLP-90N
LLP-90AF	2	LLP-90N
Residential		
R-21 F	2366	R-80
R-04-21F	4	R-80
R-05-21F	4	R-80
R-06-21F	25	R-80
R-08-21F	9	R-80
R-70N-B	226	R-80
R-70N-B Weekend		R-80
R-70N-C	684	R-80
R-70N-C Weekend		R-80
R-70N-D	485	R-80
R-70 F	4010	R-80
R-04-70F	6	R-80
R-05-70F	16	R-80
R-06-70	109	R-80
R-08-70	24	R-80
R-06-201B	12	R-201BN
R-06-201C		R-201BN
R-08-201B		R-201BN
R-08-201C		R-201BN
R-201BN	58	R-201BN
R-201BF	473	R-201BN
R-201CF	151	R-201BN
R-201CN	18	R-201BN

* Source for number of customers - Exhibit CAJ-1 Corrected 8-17-12 page 1 of 2

Testimony - Howard Solganick

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

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

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

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

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

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

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.

Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)

Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

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

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

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Exhibit HS-6
Copies of Responses to data requests and documents reference in the Direct Rate design Testimony of Howard Solganick

Data Request/Workpaper No.	Confidential	No of Pages	Page No.
DOD 1.03 (4)	NO	6	6
STF 1.020	NO	1	9
STF 21.1	NO	2	9, 17, 19
AECC 3.5 (a)	NO	1	9
STF 1.032	NO	2	9, 14
AECC 3.1 (c)	NO	2	9, 14
AECC 6.1 (b) (i)	NO	4	9
VSI 3.02	NO	1	12
STF 1.008	NO	1	13
STF 1.006	NO	1	13
STF 1.079	NO	1	13, 24
STF 1.005	NO	1	13, 26
STF 1.007	NO	1	13
STF 1.041	NO	1	14
STF 1.031	NO	4	14
STF 1.077	NO	1	14
STF 1.037	NO	1	14
Worksheet R-01	NO	4	16
TEP email to Staff	NO	2	16
AECC 11.4	NO	1	17
EMAIL TO STAFF	NO	2	20, 31`
STF 1.083	NO	1	24
STF 1.003	NO	1	24
STF 1.065	NO	4	28
TEP Email to Staff	NO	2	28
STF 1.093	NO	14	30
STF. 1.094	NO	2	30
STF 1.096	NO	1	32
STF 1.097	NO	1	32
STF 1.100	NO	7	34

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Exhibit HS-7
Confidential Responses to Data requests and documents reference in the Direct Rate design Testimony of Howard Solganick

Data Request/Workpaper No.	Confidential	No of Pages	Page No.
STF 1.076	YES	14	14

DOD 1.03

Please provide the following for each class for calendar years 2009, 2010, 2011 actual and 2011 adjusted:

1. Monthly customer count, revenues, revenues per customer, kWh sales and kWh sales per customer.
2. Total monthly billing demands, where applicable.
3. Monthly non-coincident class peak demands ("NCP")
4. Monthly retail system peaks in megawatts ("MW"). Indicate day and time of peak.
5. Monthly class peaks in MW coincident with monthly system peaks.
6. Annual load duration curve with supporting data.

RESPONSE: October 12, 2012

1. Please see the files listed below for actual customer count, revenues and sales for 2009, 2010 and 2011.

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

File Name	Bates Numbers
DOD 1.03 01-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 02-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 03-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 04-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 05-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 06-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 07-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 08-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 09-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 10-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 11-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 12-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 2010-2011 OperRevReport-Confidential.xlsx	N/A
DOD 1.03-1-Confidential.xls	N/A

2011 adjusted revenues are in the TEP Revenue Proof 12-31-11-Confidential.xlsx provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\1. Confidential).

Adjusted Customer counts and kWh sales are in Billind Determinants adjusted monthly.xls provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\3. Schedule H Support).

Per customer data can be calculated from the above referenced worksheets.

2. 2011 actual monthly billing demands are in TEP TY Billing Determinants 12-31-11 – Confidential provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\1. Confidential).

   2011 adjusted monthly billing demands are in Billind Determinants adjusted monthly.xls provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\3. Schedule H Support).

   2009 and 2010 billing demand was not calculated for purposes of this rate case and therefore is unavailable.

3. Monthly non-coincident class peaks are in Average and Peaks Allocation 12-31-11 (Revised 10-05-12) provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\5. Load Research).

   2009 and 2010 billing demand was not calculated for purposes of this rate case and therefore is unavailable.

4. Please see DOD 1.03-4 retail system peaks.xls for 2009, 2010, and 2011 day and time retail system peaks.

5. See response to question 1.03 (3).

6. Please see DOD 1.03-6 2011 Load Duration Curve.xls for the requested information.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

SUPPLEMENTAL RESPONSE TO PARTS 2, 3 AND 5: October 26, 2012

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

In response to DOD 2.1, Please see the following:

2. Please see DOD 1.03-2-Confidential.xls for billing demand data for 2009 and 2010 for all applicable classes.

3.&5. The Company objects to DOD 1.3(3) and DOD 1.3(5), since it does not have system data readily available to generate the non-coincident peak or the coincident peak data outside the test year in a manner responsive to DOD 1.3(3) or DOD 1.3(5). To generate the requested information would be overly burdensome and time consuming.

RESPONDENT:

Pricing (A. Leschak)

WITNESS:

Craig A. Jones

REVISED RESPONSE TO PART 4: November 5, 2012

Please see DOD 1.03-4 retail system peaks-revised.xls for corrected numbers to tab 2009 from the FERC Form 1. The Excel file is not identified by Bates numbers.

RESPONDENT:

Pricing (A. Leschak)

WITNESS:

Craig A. Jones

Monthly System Peaks 2011

Line No.	Date &Time	Total system Peak (MW)
1	1/4/2011 8:00	1,286
2	2/3/2011 8:00	1,519
3	3/31/2011 17:00	1,170
4	4/28/2011 17:00	1,379
5	5/27/2011 17:00	1,721
6	6/27/2011 16:00	2,334
7	7/2/2011 16:00	2,214
8	8/24/2011 17:00	2,303
9	9/1/2011 16:00	2,199
10	10/2/2011 16:00	1,630
11	11/1/2011 17:00	1,233
12	12/6/2011 8:00	1,327
13		2,334

DOD
1.03 (4)

Monthly System Peaks 2010

Line No.	Date &Time	Total system Peak (MW)
1	1/25/2010 14:00	1,614
2	2/10/2010 20:00	1,491
3	3/10/2010 8:00	1,466
4	4/27/2010 16:00	1,548
5	5/28/2010 16:00	1,996
6	6/30/2010 16:00	2,610
7	7/15/2010 16:00	2,848
8	8/12/2010 16:00	2,696
9	9/20/2010 16:00	2,520
10	10/1/2010 16:00	2,328
11	11/30/2011 8:00	1,568
12	12/31/2010 19:00	1,607
13		2,848

Monthly System Peaks 2009

Line No.	Date &Time	Total system Peak (MW)
1	1/28/2009 8:00	3,139
2	2/11/2009 8:00	3,180
3	3/2/2009 20:00	2,970
4	4/21/2009 17:00	3,538
5	5/18/2009 17:00	3,836
6	6/29/2009 16:00	4,139
7	7/28/2009 16:00	4,348
8	8/20/2009 16:00	4,161
9	9/1/2009 16:00	3,923
10	10/19/2009 16:00	3,482
11	11/5/2009 16:00	3,144
12	12/7/2009 18:00	3,295
13		4,348

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
September 7, 2012

STF 1.020

Jurisdictional Allocation: Please provide the FERC Order or communication that indicates acceptance of the use of the 4CP methodology by the Company. [Jones Direct 12:25]

RESPONSE:

The 4CP approach was approved by FERC in settlement Order No. OA96-140-000, and has been accepted by the Commission in TEP's last three general rate cases for purposes of the jurisdictional allocation method.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TWENTY-FIRST SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 November 07, 2012

STF 21.1

The Company's response to DOD 2.2 confirms that the Unit Cost data in Schedule G-6-1 is not cost data but unit revenue data.

a. Please confirm that the data presented is revenue such as unit revenue (example) line 18 shows residential as $363,572,522 which is the same as the Residential Total Electric Revenue from Sales on line 20 on Schedule G-1.

b. Please compute the Unit Cost for each component shown on lines 1 through 18 of Schedule G-6-1 for customer, demand (kW) and energy (kWh) ASSUMING the Company's requested overall rate of return for this case.Provide the following information:

RESPONSE:

a. Yes, the Company has identified all costs necessary to serve each individual class. Schedule G-6-1 referenced in this data request includes all of these costs, including the test year actual return on rate base. The return is simply the amount of revenue left over after all expenses have been met for the test year. Since the class cost of service study ("CCOSS") is designed to determine the cost to serve each individual class, the costs and the revenues should match. Therefore, the test year "Revenue" amount of $363,572,522 for the residential class mentioned above is assumed to be the same value as the "cost" to serve that class for the test year. In this case it shows the residential test-year revenues resulted in a negative return on plant (i.e., revenues were not sufficient in the test year to produce a return on the plant used to serve this class).

b. Please see STF 21.1.xls for the unit cost by class for the test year plus the additional proposed revenues being requested by class at the Company's proposed rate of return. Adding the additional "revenue" needed to offset the "cost" associated with the return and related taxes will increase the "cost" and "revenues" for each class proportionally. All demand components are calculated on a per KW basis whereas the energy component uses sales and customer components use customers.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY REVENUES AND UNIT COST

TEST YEAR PERIOD ENDING DECEMBER 31, 2011

LINE NO.	REVENUES	TOTAL	TOTAL COMPANY	RESIDENTIAL	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING
1	**DEMAND COMPONENTS**	$632,382,196	$632,382,196	$274,512,306	$181,093,756	$92,989,020	$40,613,160	$40,064,661	$3,109,293
2	DEMAND PRODUCTION		365,436,713	158,296,072	101,032,137	54,916,536	24,115,403	24,343,209	2,733,357
3	DEMAND PRODUCTION MUST RUN		27,361,991	11,908,943	7,491,405	4,086,145	1,821,229	1,846,496	207,773
4	DEMAND TRANSMISSION EHV		51,016,770	24,783,234	10,585,789	6,492,350	4,133,510	4,577,520	444,368
5	DEMAND TRANSMISSION NON-EHV		51,016,770	24,783,234	10,585,789	6,492,350	4,133,510	4,577,520	444,368
6	DEMAND ANCILLARY SERVICES		17,144,607	7,461,962	4,694,000	2,560,316	1,141,154	1,156,986	130,187
7	DEMAND DISTRIBUTION		120,405,345	47,278,861	46,704,636	18,441,323	5,268,355	3,562,930	(850,760)
8	**ENERGY COMPONENTS**	292,189,698	292,189,698	121,102,785	69,067,097	40,234,780	27,174,234	33,425,978	1,184,824
9	ENERGY FUEL DIRECT		292,189,698	121,102,785	69,067,097	40,234,780	27,174,234	33,425,978	1,184,824
10	ENERGY PRODUCTION		0	0	0	0	0	0	0
11	ENERGY CUSTOMER		0	0	0	0	0	0	0
12	ENERGY UNCOLLECTIBELS		0	0	0	0	0	0	0
13	**CUSTOMER COMPONENTS**	$40,126,025	$40,126,025	$27,998,899	$8,158,634	$1,456,340	$819,725	$715,662	$976,765
14	CUSTOMER DELIVERY		11,425,770	6,442,161	3,029,427	721,593	431,419	347,164	454,005
15	CUSTOMER METERS		9,011,558	4,980,043	3,043,401	420,601	207,536	172,659	187,318
16	CUSTOMER BILLING & COLLECTIONS		16,013,025	13,430,713	1,691,213	255,402	147,019	159,278	329,399
17	CUSTOMER METER READING		3,675,673	3,145,981	394,592	58,744	33,751	36,561	6,043
18	**TOTAL COMPANY**	**$964,697,920**	**$964,697,920**	**$423,613,990**	**$258,319,487**	**$134,680,140**	**$68,607,120**	**$74,206,301**	**$5,270,882**
	PER UNIT COST								
19	**DEMAND COMPONENTS**	$28.9894	$28.9894	$31.7304	$43.0316	$30.6630	$24.6241	$23.6782	$1.2049
20	DEMAND PRODUCTION		$16.7522	$18.2971	$24.0073	$18.1087	$14.6214	$14.3868	$1.0593
21	DEMAND PRODUCTION MUST RUN		$1.2543	$1.3765	$1.7801	$1.3474	$1.1042	$1.0913	$0.0805
22	DEMAND TRANSMISSION EHV		$2.3387	$2.8646	$2.5154	$2.1408	$2.5062	$2.7053	$0.1722
23	DEMAND TRANSMISSION NON-EHV		$2.3387	$2.8646	$2.5154	$2.1408	$2.5062	$2.7053	$0.1722
24	DEMAND ANCILLARY SERVICES		$0.7859	$0.8625	$1.1154	$0.8443	$0.6919	$0.6838	$0.0505
25	DEMAND DISTRIBUTION		$5.5196	$5.4649	$11.0980	$6.0810	$3.1942	$2.1057	-$0.3297
26	**ENERGY COMPONENTS**	$13.3945	$13.3945	$0.0312	$0.0317	$0.0329	$0.0295	$0.0309	$0.0317
27	ENERGY FUEL DIRECT		$13.3945	$0.0312	$0.0317	$0.0329	$0.0295	$0.0309	$0.0317
28	ENERGY PRODUCTION		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
29	ENERGY DEMAND SIDE MANAGEMENT		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
30	ENERGY UNCOLLECTIBELS		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
31	**CUSTOMER COMPONENTS**	$1.8394	$1.8394	$6.3299	$18.2523	$195.5869	$4,554.0277	$29,819.2698	$4.1600
32	CUSTOMER DELIVERY		$0.5238	$1.4564	$6.7773	$96.9101	$2,396.7718	$14,465.1467	$1.9336
33	CUSTOMER METER READING		$0.4131	$1.1259	$6.8086	$56.4868	$1,152.9771	$7,194.1368	$0.7978
34	CUSTOMER BILLING & COLLECTIONS		$0.7341	$3.0364	$3.7835	$34.3006	$816.7739	$6,636.5914	$1.4029
35	CUSTOMER METERS		$0.1685	$0.7112	$0.8828	$7.8894	$187.5049	$1,523.3950	$0.0257
36	**TOTAL COMPANY**	$44.2233	$44.2233	$38.0914	$61.3155	$226.2828	$4,578.6812	$29,842.9788	$5.3966
37	**TOTAL THRUPUT (kWh)**	9,332,107,046	9,332,107,046	3,887,303,965	2,179,138,260	1,222,821,614	922,341,014	1,083,071,404	37,430,790
38	**TOTAL ANNUAL CUSTOMERS**	5,112,747	5,112,747	4,423,307	446,993	7,446	180	24	234,797
39	**TOTAL AVERAGE CUSTOMERS**		426,062	368,609	37,249	621	15	2	19,566
40	TOTAL CUSTOMER ($/ CUSTOMER)		$7.85	$6.33	$18.25	$195.59	$4,554.03	$29,819.27	$4.16
41	TOTAL DEMAND & CUSTOMER ($/ CUSTOMER)		$131.54	$68.39	$423.39	$12,684.04	$230,182.70	$1,699,180.13	$17.40

AECC 3.5

Class Cost of Service - Please refer to the CCOS study provided in TEP's response to AECC DR No. 1-7. Please answer the following questions related to each class's share of income tax under present rates.

a. Please explain why TEP allocates total jurisdictional income tax expense using plant in service instead of directly calculating each class's income tax expense using each class's taxable net income derived using its revenues and expenses other than income taxes?

b. Would TEP agree that allocating income taxes using plant in service assigns excess taxes to classes with earnings below the system average and assigns insufficient taxes to classes with earnings above the system average? If not, please explain how TEP's allocation of income taxes results in an appropriate level of income tax expense for each rate class.

c. Please prepare a CCOS study that derives each class's earnings under present rates with the income taxes calculated for each rate class based on its class-specific taxable net income under present rates instead of the income taxes being allocated using plant in service.

RESPONSE:

a. The allocation of income taxes should be based on what each class should be paying if there were an equalized return on plant. To apply taxes in the manner suggested in this question would make existing inequities between classes even more inequitable. An example of this inequity would be to assume only one class is generating a positive return on plant (thus income). It would be unjust and unreasonable to allocate to it <u>all</u> of the income tax to that single class. This would result in the customers who are not covering their cost of service to pay even less, and those covering more than their cost of service to pay even more. The Company's believes its method is considerably more equitable.

b. No, the Company does not agree. See the response to part a.

c. The Company objects to preparing a new CCOSS. AECC has been provided the Company's CCOSS in electronic format. AECC, therefore,has the capability to run different versions of the study based on its own assumptions. It would be overly burdensome for the Company to create a series of calculations and perform the necessary test for validity related to creating changes that assign all of the income tax costs to classes that the Company believes are already paying more than their share of the costs.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

STF 1.032

Cost of Service: Please provide the system loss study used in the Cost of Service Study.

RESPONSE:

The Company did not prepare a system loss study in this rate case. Distribution and transmission losses used in the CCOSS are prepared in Excel and included in the file 2011 Jurisdictional Allocation 12-31-11.xlsx, tab Loss Summary, which was provided in the revised response to UDR 1.1 dated August 17, 2012. This file 2011 Jurisdictional Allocation 12-31-11.xlsx can be found in the data response under the headings CCOSS: Jurisdictional Allocation.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY
ACC/FERC JURISDICTION - ENERGY /DEMAND ALLOCATION
TEST PERIOD YEAR END DECEMBER 31, 2011

#N/A

ENERGY ALLOCATON - BASE CASE

Line No.			ACC (a)	FERC (b)	Total (c)	Line No.
1	Sales to ultimate customers including unbilled		1,083,071,404	1,032,598,000	2,115,669,404	1
	Adjustments:					
2	Year-end Customers and Weather Normalization		(46,514,056)		(46,514,056)	2
3	TOTAL		1,036,557,348	1,032,598,000	2,069,155,348	3
	Local Losses					
4	As % of Sales		6.39%			4
5	kWh	(Line 3 * Line 4)	66,245,035		66,245,035	5
6	Local Generation and Deliveries from EHV	(Line 3 + Line 5)	1,102,802,383	1,032,598,000	2,135,400,383	6
	EHV Losses					
7	As % of Deliveries/Sales		3.85%	3.85%		7
8	kWh	(Line 6 * Line 7)	42,434,243	39,732,880	82,167,122	8
9	Energy Required	(Line 6 + Line 8)	1,145,236,626	1,072,330,880	2,217,567,506	9
10	**Energy Allocation Factor** (Line 9 - (a)/(c) and (b)/(c)		**51.64%**	**48.36%**		10

AECC 3.1

Class Cost of Service - Please refer to the Average and Peaks Excel workpaper file "Average and Peak Allocation 12-31-2011". In cells N53:N64, TEP provides monthly coincident peak (CP) demand losses.

a. Please confirm that these loss values are correct for each month. If these values are incorrect, please provide corrected monthly losses.

b. If these values are correct, please explain how the monthly demand losses can vary from a low of 1.8% in December 2011 to a high of 30.4% in July 2011 (calculated by dividing the values in cells N53:N64 by the values in cells N38:N49). Even taking account of summer losses, shouldn't the CP loss percentages be more consistent than this across all months?

c. Please provide a copy of TEP's most recent line loss study.

d. Please confirm that TEP has customers that take service variously at Secondary voltage, Primary voltage, non-EHV, and EHV. If this statement is incorrect, please identify the error(s) and explain why the statement is in error.

e. Please identify the voltage (secondary, primary, etc.) at which service is provided for each of the eleven TEP rate classes shown in the workpaper. If service for any rate class is provided at more than one voltage level, please identify the proportion of that rate class's monthly non-coincident peak (comparable to cells C6:M17) and monthly coincident peak (comparable to cells C21:M32) that is served at each applicable voltage.

f. Please explain why the loss values TEP applied to each rate class in its CCOS are not differentiated by voltage level.

g. Please provide the monthly CP demand loss factors applicable to each of the voltage levels at which TEP retail customers take service, i.e., secondary, primary, non-EHV, and EHV (or other applicable categories).

h. Please provide the comparable workpaper from TEP's 2007 rate case, including losses. Please explain the reason for any major changes in demand losses between the 2007 rate case and the current case.

RESPONSE:

a. Load Research demand was not adjusted for losses back to generation. Cells N53:N64 represent the excess or shortfall to the difference between the system monthly coincident-peak loads less the summation of coincident peak for all class loads based on load research data. The hourly load data was then grossed up by allocating the excess or shortfall proportionately to classes.

b. See response to part a.

c. The Company has not completed an engineering study on line losses over the last two rate cases. The losses calculated and used in the jurisdictional allocation have been provided in response to UDR 1.1 (jurisdictional allocation can be located in TEP's electronic data room, see Uniform Data Requests\Attachments\UDR 1.01\WP – Schedules\Schedule G and H Support\ Jurisdictional Allocation \2011 Jurisdictional Allocation 12-31-11.xlsx).

d. Correct.

e. The chart below shows the percentage of services at voltage levels, and primary or secondary service by rate class. For those classes that have services, or more than one service, under different voltages, the Company does not have that hourly load data readily available.

Class Description	Non-EHV (≤49 kV)	EHV (≥138 kV)	Secondary	Primary
Residential	100%	0%	100%	0%
Residential TOU	100%	0%	100%	0%
Small Commercial	100%	0%	94%	6%
Small Commercial TOU	100%	0%	100%	0%
Large Commercial	100%	0%	94%	6%
Large Commercial TOU	100%	0%	98%	2%
Water Pumping	100%	0%	100%	0%
Lighting	100%	0%	100%	0%
LL&P	100%	0%	7%	93%
LL&P TOU	100%	0%	71%	29%
Mining	91.3%	8.7%	0%	100%

f. See response to a and c.

g. TEP does not track or bill information that would be responsive to this request.

h. Please see AECC 3.1-h.xls for the Average & Peaks workpaper from the 2007 rate case. There are no changes in the methodology between work papers.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY
ACC/FERC JURISDICTION - ENERGY /DEMAND ALLOCATION
TEST PERIOD YEAR END DECEMBER 31, 2011

#N/A

ENERGY ALLOCATON - BASE CASE

Line No.			ACC	FERC	Total	Line No.
			(a)	(b)	(c)	
1	Sales to ultimate customers including unbilled		1,083,071,404	1,032,598,000	2,115,669,404	1
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7	As % of Deliveries/Sales		3.85%	3.85%		7
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10	**Energy Allocation Factor** (Line 9 - (a)/(c) and (b)/(c)		**51.64%**	**48.36%**		10

AECC 6.1

Follow up to TEP's Response to AECC 3.1.a.

a. Please define "Load Research demand" as used in TEP's response. In answering this question please indicate whether "Load Research demand" is referring to the demand of all retail load or just the load for which sampling techniques are used to derive class hourly loads.

b. Please clarify the statement "Load Research demand was not adjusted for losses back to generation" in light of the fact that heading of the cells being discussed (cell N52 of the workpaper entitled "Average and Peaks Allocation 12-31-2011") is entitled "Losses." Specifically:

   i. Is TEP indicating that the heading "Losses" is incorrect? If the heading "Losses" is not incorrect, please clarify in light of the statement quoted above.

   ii. Is TEP indicating that cells N53:N64 include losses but that a loss factor was not applied to derive the values in these cells?

   iii. If cells N53:N64 are accounting for items other than losses, identify each of those items.

   iv. Please confirm that the values shown under the heading "Losses" exceed 18% for each month from April to October (calculated by dividing the values in cells N53:N64 by the values in cells N38:N49). If TEP disagrees, please reconcile using the values in the workpaper. If these cells (N53:N64) are simply the difference between the monthly coincident peak load that TEP has measured using its Load Research data and TEP's system monthly peak, what proportion of the April through October "Losses" is attributable to a measurement error in which TEP's load research data fails to reconcile to TEP's measured system output after adjusting for reasonable losses (e.g., 9.6%)? If TEP disputes that a material portion of these reported "Losses" values is attributable to a measurement error as described above, please fully account for the "Losses" value for each month for which the reported "Losses" deviates from the 9.6% Annual Average Loss Factor used by TEP elsewhere in its workpapers.

   v. Please reconcile the monthly "Losses" in cells N53:N64 to the monthly Losses shown in Schedule G Support Workpaper entitled "2011 TEP Average Peaks Summary." Is the difference in the "Losses" presented in these two workpapers attributable wholly (or largely) to the inclusion in cells N53:N64 of a measurement error in which TEP's load research data fails to reconcile to TEP's measured system output? If not, please explain in the reconciliation these two sets of reported "Losses".

vi. Please explain TEP's rationale in assigning a pro rata share of the difference between the monthly coincident peak load that TEP has measured using its Load Research data and TEP's system monthly peak to classes for which monthly coincident peak was measured using the aggregated load of the class population (as opposed to a statistical sample). Does TEP agree that this pro rata allocation assigns a portion of the measurement error attributable to statistical sampling to the classes for which class load was derived based on the measured load of the class population? If TEP disagrees, please fully explain the basis of TEP's disagreement.

c. Please refer to the load data in cells C21:M32 in workpaper entitled "Average and Peaks Allocation 12-31-2011.

i. For each class shown in this range of cells, please indicate which class load data was derived using a statistical sample and which class load was derived by aggregating the measured load of the class population.

ii. What is the class population (i.e., number of annual customers) of each class shown in this range of cells?

iii. What is the sample size of each class for which a statistical sample was used to derive monthly coincident peak loads?

iv. What is the age of the sample for each class for which a statistical sample was used to derive monthly coincident peak loads?

v. Please describe the specific sampling philosophy that the Company employs for its load studies. Does TEP employ Stratified Random Sampling or Simple Random Sampling? What are the confidence bounds used in determining the sample size for each class for which a statistical sample was used to derive monthly coincident peak loads. Please show this calculation.

vi. Please provide the workpaper (in Excel format with all formulas intact) that shows how the sample load data for each class (for which a statistical sample was utilized) is used to estimate class monthly coincident peak loads.

vii. For each class for which a statistical sample was used to derive monthly coincident peak loads, please provide a table that identifies the monthly kWh that is predicted by the sample load data and compares it to actual class kWh, for each month in 2011.

RESPONSE:

a. "Load Research Demand" refers to the demand amounts arrived at for classes not having demand meters and is based on the sample data which is then converted to generate a value for the class.

b. i. The heading referenced in this question does not thoroughly describe everything that is included in the data in the column below it. The data in the column does include the value of average system losses allocated to each class, but it also includes the allocation of variance amounts resulting from load research data. No specific amount was added to the class, the total variance (which would include the loss amount) itself was allocated to each class as shown on the spreadsheet. This column could be referred to as the "balancing adjustment".

ii. Yes.

iii. Please refer to the response to AECC 6.1b.i.

iv. TEP confirms that the values shown under the "Losses" exceed 18% for each month from April to October.

The adjustment mentioned in the column originally labeled "losses" is, as stated in the question, simply the difference between the monthly coincident peak load that TEP calculates based on its load research data and TEP's system peak. Since not all customers have demand meters, the monthly class demand is modeled using the load research for those classes without demand meters. Losses are not identifiable by rate class, so they are assumed to be part of the overall difference between the calculated peak based on load research and the system peak. If the total system demand for the year is 20,313 MW and the losses are the stated 9.6%, then 1,950 MW of the 2,749 MW difference between the load-research based peak and the system peak relate to the estimated losses. Since losses are likely to vary in any given month for a variety of reasons, this calculation is just an approximation. Some portion of the remaining 799 MW of difference can be assumed to be the adjustment necessary to make the numbers match. It is not a measurement error as characterized in this question, it is simply the balancing adjustment necessary to align the two forms of data.

v. Please see the response to AECC 6.1b.iv.

vi. As mentioned in the response to AECC 6.1b.iv., the differences were primarily attributable to losses. Since the data is not available to determine the specific losses by customer class, it was determined that a proportional allocation of those differences to all classes was appropriate. There are a number of variables (temperature, voltage, load factor, etc.) that could contribute to more or less of the losses being allocated to individual classes or individual months, but the data necessary to arrive at a specific calculation is not available. Since the variables could increase or decrease the amount of losses going to any individual class or month, it was determined that allocating the entire total of the balancing adjustment on a weighted basis would be the most equitable method of assigning the balancing adjustment to all classes.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO THE VOTE SOLAR INITIATIVE'S ("VSI") THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 December 27, 2012

VSI 3.02

Please describe the time frame over which TEP plans to achieve 100% deployment of "smart meters" for its residential, commercial, and industrial customers, and for the remainder of its distribution feeders. (follow-up to VSI 2.02)

RESPONSE:

The residential class has 177,211 automated meter reading ("AMR") meters installed out of 390,128 total meters. TEP plans to have the remaining meters exchanged within 6 years.

The commercial class has 16,276 AMR meters installed out of 39,155 total meters. TEP plans to have the remaining meters exchanged within 5 years.

The industrial class has 108 meters and all of them currently have a Smart Meter installed.

TEP has 277 Smart Meters installed on 408 distribution feeders. The remaining 131 feeders have meters that provide the data needed at this time. There are no plans to replace any of the remaining 131 meters with Smart Meters.

RESPONDENT:

Jim Taylor

WITNESS:

Craig A. Jones

STF 1.008

Background: Does the Company use competitive fuel (or energy) forecasting for any customer classes? If so, please provide a narrative description of the process, price inputs and results beginning January 1, 2008 through 2012.

RESPONSE:

No, the Company does not use competitive fuel (or energy) forecasting for any customer classes..

RESPONDENT:

David Couture

WITNESS:

David Hutchens

STF 1.006

Background: Does the Company employ end use forecasting for any customer classes? If so, please provide a narrative description of the process and results beginning January 1, 2008 through 2012.

RESPONSE:

No, the Company does not currently have the capability to construct end-use forecasts, and does not foresee being able to construct such forecasts for several years.

RESPONDENT:

Pricing (Craig A. Jones and Luc Thiltges)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 September 7, 2012

STF 1.079

Rate Design: Please provide any studies by Black & Veatch and/or the Company to compare the TOU price differentials to customer's costs to shift load between on and off peak periods and the potential increase in the number of customers that will change to the proposed TOU rates as a result. [DesLauriers Direct 28:11]

RESPONSE:

No such study has been conducted by the Company or Black & Veatch to its knowledge. The customers' costs to shift load is not an element of the analysis of optimal TOU periods since the purpose of TOU is to signal cost consequences for the Company to customers for them to use in evaluating their own individual economics of load shifting.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

STF 1.005

Background: Does the Company have a program or process to survey its commercial and/or industrial sector customers to determine their plans for operations, expansion or other changes? If so, please provide a narrative describing the program and summaries of the results for 2008, 2009, 2010, 2011 and 2012.

RESPONSE:

The Company employs a small Key Account Management group to address the electric utility service needs of its large commercial and industrial customers. Key Account Management provides the primary point of contact with large commercial and industrial customers and is tasked with fostering and maintaining positive relationships while ensuring proper regulatory compliance. While the Company does not have a formal process to survey its commercial and industrial customers, TEP uses this information in its load forecasting and planning processes, but does not keep the results of such discussions (or the information is provided confidentially to TEP by its customers and may not be released without their prior permission).

RESPONDENT:

David Couture

WITNESS:

David Hutchens

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 September 7, 2012

STF 1.007

Background: Does the Company perform appliance saturation studies for any customer classes? If so, please provide a narrative description of the process and results beginning January 1, 2008 through 2012.

RESPONSE:

The Company has not completed any specific appliance saturation studies by customer class for the periods January 2008 through 2012. However, a 2010 Targeted Baseline Study for EE was completed by Navigant Consulting, which included appliance saturation data for surveyed homes and businesses. The Company utilized the baseline study in the design, evaluation, and planning for its EE Programs. The study will be made available upon request.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

Arizona Corporation Commission ("Commission")
Federal Energy Regulatory Commission ("FERC")
Lost Fixed Cost Recovery ("LFCR")
Time of Use ("TOU")
Tucson Electric Power Company ("TEP" or the "Company")
UNS Energy Corporation fka UniSource Energy Corporation ("UNS")
UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric")
UNS Gas, Inc. ("UNS Gas")

STF 1.041

Rate Design: Please provide any studies, investigations, analyses or reviews performed by or for the Company that considered, evaluated or reviewed the income distribution versus consumption by rate schedule.

RESPONSE:

The Company has not evaluated or reviewed the income distribution versus consumption by rate schedule.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 September 7, 2012

STF 1.031

Cost of Service: Please provide in an Excel worksheet the coincident peak (CP), non-coincident peak (NCP), energy sales (both as metered and corrected to a common generation voltage) and number of customers for each month beginning January 2008 through the present for the Company as a whole and for each of the retail customer classes (as shown on Schedules G-1 and G-2).

RESPONSE:

The file Average & Peaks Allocation 12-31-11.xls supports the coincident peak demand and non-coincident peak demand for the Company and all rate classes for the test year. That file was provided in the revised response to UDR 1.1 dated August 17, 2012, in subfolder "Schedule G & H Support\5. Load Research". The Company peak demand is in the attached file STF 1.031.pdf, Bates Nos. TEP\014883-014885 for 2008 through 2010, source FERC Form 1.

The NCP data has been compiled for the test year for allocation purposes and is not readily available for the years 2008 through 2010, nor is available with forecast assumptions for calendar years 2012 through 2014.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tucson Electric Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2010	End of 2009/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,096,394	381,751	1,469	29	0800
30	February	969,897	336,566	1,476	27	0800
31	March	1,028,086	332,268	1,399	31	2000
32	April	1,057,331	358,395	1,845	30	1700
33	May	1,326,288	408,222	2,193	29	1700
34	June	1,398,744	450,260	2,492	7	1600
35	July	1,576,756	413,664	2,670	30	1600
36	August	1,547,599	406,860	2,725	31	1600
37	September	1,302,396	340,573	2,330	30	1600
38	October	1,123,406	342,189	1,921	30	1600
39	November	1,132,957	436,021	1,598	28	1600
40	December	1,119,845	432,954	1,598	1	1800
41	TOTAL	14,679,699	4,639,723			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tucson Electric Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2011	End of 2010/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,011,116	320,464	1,614	25	1400
30	February	956,765	385,485	1,491	10	2000
31	March	995,341	260,947	1,466	10	800
32	April	966,844	270,994	1,548	27	1600
33	May	1,066,816	275,102	1,996	28	1600
34	June	1,348,014	361,383	2,610	30	1600
35	July	1,539,073	403,240	2,848	15	1600
36	August	1,534,300	409,249	2,696	12	1600
37	September	1,388,957	388,320	2,520	20	1600
38	October	1,201,832	418,873	2,328	1	1600
39	November	1,092,684	408,369	1,568	30	800
40	December	1,086,249	383,035	1,607	31	1900
41	TOTAL	14,187,991	4,285,461			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tucson Electric Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2009	End of 2008/Q4

MONTHLY PEAKS AND OUTPUT

(1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
(2) Report on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,228,526	483,681	1,399	18	800
30	February	1,034,742	349,236	1,389	5	800
31	March	1,126,815	433,156	1,247	25	2000
32	April	1,136,521	406,453	1,544	29	1700
33	May	1,335,306	509,330	2,030	20	1700
34	June	1,697,128	637,024	2,666	16	1600
35	July	1,625,934	532,219	2,600	1	1600
36	August	1,577,224	473,460	2,650	1	1600
37	September	1,452,260	470,836	2,285	5	1600
38	October	1,309,196	538,340	2,039	1	1600
39	November	1,182,933	485,902	1,633	1	1600
40	December	1,239,090	517,587	1,452	15	1900
41	TOTAL	15,945,675	5,837,224			

STF 1.077

Rate Design: Please provide the loss study used for the "losses associated with the voltage level of service" considered by Black & Veatch and/or the Company. [DesLauriers Direct 23:17]

RESPONSE:

Neither Black & Veatch nor the Company conducted a loss study. Black & Veatch computed a high voltage (138+kv) and all other (low voltage) (<138kv) loss factor using existing loss data supplied by the Company and back-solving using other known factors. Black & Veatch first converted monthly loss data (provided by the Company) for power delivered at 345kv to monthly factors expected at 138kv. Black & Veatch then solved for monthly low voltage delivery factors using forecasted generation and load by month for system, high voltage customers, and system losses. Black & Veatch computed these factors so that the weighted average of high-voltage losses and all other (low-voltage) losses produce the average forecasted retail sales level losses across the system. Please refer to the direct testimony of David F. DesLauriers at page 33, lines 19-21. Please also refer to Exhibit 8, page 2 of 6 for a derivation of these loss factors.

RESPONDENT:

David F. DesLauriers

WITNESS:

David F. DesLauriers

STF 1.037

Cost of Service: Has the Company performed any marginal cost studies in contrast to embedded cost studies? If so, please provide a summary of each study.

RESPONSE:

The Company has not performed any marginal cost studies. The Company did use its embedded CCOSS for its rate design proposals included in this application in a manner similar to that filed in its previous rate applications. The CCOSS, with all work papers in tact was provided in the revised response to UDR 1.1 dated August 17, 2012, as the file Schedule G.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

WORKPAPERS:

UDR 1.1

Workpapers. Please provide a complete set of supporting workpapers for all schedules, analysis, calculations and witness testimony in TEP's filing. Provide all in Excel format with formulas and cross references intact where applicable.

SUPPLEMENTAL RESPONSE: July 16, 2012

Please see original response provided to Commission Staff on July 13, 2012. Additionally, please see the file DeConcini – Direct Workpapers-Confidential.pdf, Bates Nos. TEP\014755 to TEP/014845 on the enclosed CD.

Bates Nos. TEP\014755 to TEP/014845 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

RESPONDENT:

Regulatory Services

SUPPLEMENTAL RESPONSE: September 7, 2012

Please see original response provided to Commission Staff on July 13, 2012. Additionally, please see the following files:

- LFCR POA Schedules.xls for the electronic version of Schedules 1 through 5 of Mr. Craig A. Jones's Lost Fixed Cost Recovery Plan of Administration, as proposed in Exhibit CAJ-5 to his direct testimony; and
- 8. Annual Bill Impacts CAJ-1 corrected (2).xls for the electronic version of Exhibit CAJ-1 to Mr. Jones' direct testimony.

Please note that the file A1. Mic Service Revenue 12-31-10.xls was mistakenly included in UDR 1.1 and has been deleted from TEP's data room.

RESPONDENT:

Regulatory Services

ANNUAL BILL IMPACTS PROPOSED COMPARED TO CURRENT RATES WITH CURRENT PPFAC

Line No.	Class Description	Customer Counts To-date 5/2012	New Summer A	Summer Change B	Total Summer Change C=(B*5)	New Winter D	Winter Change E	Total Winter Change F=(E*7)	Annual Bill G=(A*5+D*7)	Annual Bill Change H=(C+F)	Revised Percent Change to Total Bill
1	Residential R-01	330,848	$117.78	$16.63	$83.17	$60.61	$6.01	$42.06	$1,013.16	$125.23	14.1%
2	Residential Lifeline R-04-01	819	$91.33	$19.47	$97.33	$48.46	$8.71	$60.98	$795.87	$158.31	24.8%
3	Residential Lifeline R-05-01	1,722	$91.33	$9.88	$49.42	$48.46	$3.03	$21.24	$795.87	$70.66	9.7%
4	Residential Lifeline R-08-01	1,046	$91.33	$29.05	$145.24	$48.46	$11.55	$80.86	$795.87	$226.10	39.7%
5	Residential Lifeline R-06-01	13,376	$107.78	$19.95	$99.77	$50.61	$1.83	$12.81	$893.16	$112.58	14.4%
6	Residential TOU R-21F	2,366	$110.51	$17.38	$86.91	$62.30	$18.27	$127.92	$988.66	$214.83	27.8%
7	Residential Lifeline R-04-21F	4	$86.63	$24.11	$120.54	$50.48	$19.89	$139.21	$786.49	$259.75	49.3%
8	Residential Lifeline R-05-21F	4	$86.63	$15.77	$78.86	$50.48	$15.52	$108.62	$786.49	$187.48	31.3%
9	Residential Lifeline R-08-21F	9	$86.63	$32.44	$162.22	$50.48	$22.07	$154.51	$786.49	$316.73	67.4%
10	Residential Lifeline R-06-21F	25	$100.51	$25.14	$125.72	$52.30	$16.60	$116.22	$868.66	$241.94	38.6%
11	Residential TOU R-70F	4,010	$110.51	($9.04)	($45.21)	$62.30	$25.02	$175.16	$988.66	$129.95	15.1%
12	Residential Lifeline R-04-70F	6	$86.63	$17.86	$89.30	$50.48	$18.76	$131.33	$786.49	$220.63	39.0%
13	Residential Lifeline R-05-70F	16	$86.63	$8.69	$43.45	$50.48	$14.23	$99.61	$786.49	$143.06	22.2%
14	Residential Lifeline R-08-70F	24	$86.63	$27.03	$135.14	$50.48	$21.03	$147.19	$786.49	$282.33	56.0%
15	Residential Lifeline R-06-70F	109	$100.51	$16.81	$84.06	$52.30	$14.99	$104.96	$868.66	$189.02	27.8%
16	Residential R-201AF	4,617	$110.48	$1.14	$5.69	$57.57	$13.07	$91.50	$955.38	$97.19	11.3%
17	Residential Lifeline 05- 201AF	3	$85.86	$28.94	$144.71	$46.18	$3.56	$24.89	$752.54	$169.60	29.1%
18	Residential Lifeline 08- 201AF	12	$85.86	$42.33	$211.66	$46.18	$11.55	$80.84	$752.54	$292.50	63.6%
19	Residential Lifeline 06- 201AF	336	$100.48	$41.52	$207.58	$47.57	$2.29	$16.05	$835.38	$223.63	36.6%
20	Residential R-201BF	473	$101.27	$2.39	$11.94	$48.46	$11.00	$76.97	$845.55	$88.91	11.8%
21	Residential Lifeline 05- 201BF	0	$81.95	$2.94	$14.71	$48.35	$19.06	$133.39	$748.24	$148.10	24.7%
22	Residential Lifeline 06- 201BF	12	$94.27	$9.32	$46.59	$49.47	$20.85	$145.94	$817.66	$192.53	30.8%
23	Residential Water Heating R-02	1,947	$15.16	$2.10	$10.52	$7.58	($1.50)	($10.48)	$128.89	$0.04	0.0%
24	Residential Time-of-Use R-21 Frozen	2,366	$110.51	$17.38	$86.91	$62.30	$18.27	$127.92	$988.66	$214.83	27.8%
25	Residential Time-of-Use R-70 Frozen	4,010	$110.51	($9.04)	($45.21)	$62.30	$25.02	$175.16	$988.66	$129.95	15.1%
26	Residential TOU 70N-B	226	$110.51	$22.97	$114.84	$62.30	$4.77	$33.39	$988.66	$148.23	17.6%
27	Residential TOU 70N-C	684	$110.51	$17.53	$87.64	$62.30	$5.50	$38.52	$988.66	$126.16	14.6%
28	Residential TOU 70N-D	485	$110.51	$17.68	$88.42	$62.30	$4.49	$31.45	$988.66	$119.87	13.8%
29	Residential TOU 201AF	4,617	$110.48	$1.14	$5.69	$57.57	$13.07	$91.50	$955.38	$97.19	11.3%
30	Special Residential Service 201AN	6,059	$110.48	($18.29)	($91.45)	$57.57	$18.11	$126.77	$955.38	$35.32	3.8%
31	Residential TOU 201BF	473	$101.27	$2.39	$11.94	$48.46	$11.00	$76.97	$845.55	$88.91	11.8%
32	Residential TOU 201CF	151	$71.16	($2.76)	($13.81)	$40.73	$20.84	$145.89	$640.92	$132.08	26.0%
33	Special Residential Service 201BN	58	$104.27	$3.43	$17.14	$59.47	$17.77	$124.37	$937.66	$141.51	17.8%
34	Special Residential Service 201CN	18	$104.27	$36.48	$182.40	$59.47	$17.29	$121.01	$937.66	$303.41	47.8%
35	General Service GS-10	34,921	$595.79	$63.61	$318.07	$388.34	$19.00	$133.01	$5,697.31	$451.08	8.6%
36	General Service PS-40	793	$1,537.83	$238.98	$1,194.88	$1,100.53	$129.69	$907.80	$15,392.86	$2,102.68	15.8%

ANNUAL BILL IMPACTS PROPOSED COMPARED TO CURRENT RATES WITH CURRENT PPFAC

Line No.	Class Description	Customer Counts To-date 5/2012	New Summer A	Summer Change B	Total Summer Change C=(B*5)	New Winter D	Winter Change E	Total Winter Change F=(E*7)	Annual Bill G=(A*5+D*7)	Annual Bill Change H=(C+F)	Revised Percent Change to Total Bill
1	Mobile Home Park Service C-11	340	$956.20	$156.04	$780.20	$1,061.39	$124.10	$868.72	$12,210.76	$1,648.92	15.6%
2	Municipal Interruptible WP Service PS-45	123	$1,503.36	$300.38	$1,502	$955.59	$32.57	$228	$14,206	$1,729.91	13.9%
3	Interruptible Agricultural Pumping C-31	38	$1,485.36	$336.76	$1,683.80	$937.59	($69.24)	($484.65)	$13,989.96	$1,199.15	9.4%
4	Municipal Water Pumping Service PS-43	414	$2,198	$333	$1,666	$1,576	$116	$813	$22,019	$2,479.33	12.7%
5	SGS Time of Use SGS-76F	814	$1,521.58	$265.85	$1,329.27	$1,030.81	$272.84	$1,909.90	$14,823.61	$3,239.17	28.0%
6	SGS Time of Use SGS-76N	105	$1,521.58	$180.93	$904.67	$1,030.81	$36.76	$257.29	$14,823.61	$1,161.96	8.5%
7	LGS Time of Use LGS-85AF	16	$8,429.21	($7,776.60)	($38,882.99)	$11,698.81	$304.11	$2,128.78	$124,037.75	($36,754.21)	-22.9%
8	LGS Time of Use LGS-85F	8	$14,757.36	($667.88)	($3,339.42)	$11,698.81	$1,791.31	$12,539.14	$155,678.48	$9,199.72	6.3%
9	LGS Time of Use LGS-85N	72	$12,934.17	$1,460.42	$7,302.09	$10,416.40	$1,409.12	$9,863.83	$137,585.63	$17,165.92	14.3%
10	Large General Service I-13	523	$16,721.47	$870.61	$4,353.04	$13,895.57	$1,744.37	$12,210.62	$180,876.32	$16,563.66	10.1%
11	Large Light & Power I-14	4	$568,236.23	$55,063.49	$275,317.47	$431,240.00	$69,440.00	$486,080.00	$5,859,861.16	$761,397.47	14.9%
12	LLP Time of Use I-90F Frozen	4	$290,039.47	($12,400.27)	($62,001.33)	$259,041.39	$15,217.31	$106,521.16	$3,263,487.09	$44,519.83	1.4%
13	LLP Time of Use I-90AF Frozen	2	$290,039.47	($20,808.98)	($104,044.90)	$259,041.39	($7,081.41)	($49,569.84)	$3,263,487.09	($153,614.74)	-4.5%
14	LLP Time of Use I-90N	4	$281,465.24	$13,264.22	$66,321.08	$252,410.12	$57,250.87	$400,756.10	$3,174,197.05	$467,077.18	17.3%
15	Mining		$2,794,852	($65,980)	($329,900)	$2,500,836	$559,972	$3,919,803	$31,480,111	$3,589,903.02	12.9%
16	Traffic Signal and Street Light Service PS-41	1,285	$209.15	$60.36	$302	$164.31	$15.51	$109	$2,196	$410.38	23.0%

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation
($000)

Attachment _

	(A)		(B)	(C)	(D)	(E)	(F) B x D x E
Line No.	Rate Schedule		Adjusted Test Year Billing Determinants	Units	Delivery Charge	Demand Stability Factor	Total Revenue
1.	Residential Service (R-01)		-	kWh	$	100%	$ -
2	Residential Service (R-80)		-	kWh	$	100%	$ -
3	Residential Service (R-201AN)		-	kWh	$	100%	$ -
4	Residential Service (R-201BN)		-	kWh	$	100%	$ -
5		subtotal	-	kWh	$		$ -
6							
7	Small General Service (GS-10)	1	-	kWh	$	100%	$ -
8	Small General Service (SGS-76)		-	kWh	$	100%	$ -
9		subtotal	-	kWh			$ -
10							
11	Large General Service (LGS-13)		-	kW	$	50%	$ -
12	Large General Service (LGS-13)		-	kWh	$	100%	$ -
13	Large General Service (LGS-85)		-	kW	$	50%	$ -
14	Large General Service (LGS-85)		-	kWh	$	100%	$ -
15		subtotal	-	kW	$		$ -
16		subtotal	-	kWh	$		$ -
17							
18	Large Light and Power (LLP-14)		-	kW	$	50%	$ -
19	Large Light and Power (LLP-14)		-	kWh	$	100%	$ -
20	Large Light and Power (LLP-90)		-	kW	$	50%	$ -
21	Large Light and Power (LLP-90)		-	kWh	$	100%	$ -
22		subtotal	-	kW	$		$ -
23		subtotal	-	kWh	$		$ -
24							
25	Total kW		-	kW	$		$ -
26	Total kWh		-	kWh	$		$ -
			-		$		$ -

note 1: Includes former Municipal PS-40 customers.

Robin Mitchell

From: howard@energytactics.com
Sent: Wednesday, January 09, 2013 2:21 PM
To: Robin Mitchell
Subject: Fwd: Follow-up to Conference Call on 9/25

Footnote 42 10/19

Begin forwarded message:

From: <jbryne@TEP.Com>
Subject: RE: Follow-up to Conference Call on 9/25
Date: October 19, 2012 11:35:31 AM EDT
To: <howard@energytactics.com>

Howard,

I know that Craig responded back to you on your first 2 questions, please see below for the response to your third question.

3 - Confirm that no load research by strata was available
Response:
No load research by strata is available.

Jessica Bryne
Regulatory Services
(520) 884-3680

-----Original Message-----
From: howard@energytactics.com [mailto:howard@energytactics.com]
Sent: Monday, October 15, 2012 6:34 AM
To: Bryne, Jessica
Cc: Robin Mitchell; Barbara Keene; Terri Ford
Subject: Follow-up to Conference Call on 9/25

Jessica

My notes indicate that during the call on the 25th that the Company said it would:

1- Determine if data for Lifeline customers (similar to H-5) was available and if so that would be sent out.

2 - Supplement STF 1.092 and provide calculations (including the supporting worksheet) for the LFCR proposal for 2012 through 2016 (as the DR asked for). This is important as it followed the discussion that the expected $36 million initial year value may be understated.

3 - Confirm that no load research by strata was available

I did receive your e mail confirming that the definitions supplemental and backup were not in the tariff, however I haven't seen responses to the other items.

Regards

Howard

AECC 11.4

In TEP's cost-of-service study, how are the costs of TEP's 46 kV facilities functionalized? Are these costs functionalized as non-EHV or primary? If these costs are functionalized as primary, please separately identify and allocate them in the Distribution Plant, Accumulated Depreciation, ADIT, and Distribution Expense accounts in Schedule G.

RESPONSE:

Distribution facilities include facilities that are below 138,000V which include 46,000V facilities and are not functionalized as non-EVH or primary cost.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

STF 1.083

Rate Design: Please provide any studies, investigations, analyses or reviews performed by or for the Company or known to the Company that measure how TOU rates are sending customers the appropriate price signals.

RESPONSE:

The Company has not conducted any such studies. The Company believes that TOU rates send customers appropriate price signals because they more closely track underlying cost causation aspects. A TOU differentiated PPFAC rate will more clearly communicate the true cost differences that exist to purchasing electricity between on and off peak periods. A non-TOU rate will not communicate this important cost difference; and in turn, customers will not have the information they need to make the most informed purchasing decisions. Please also refer to the direct testimony of David F. DesLauriers at page 29, lines 15-24 for additional support as to why TOU rates send appropriate price signals. The key element of any price signal is for proposed rates to reflect, to the extent practicable, the actual costs of the Company.

RESPONDENT:

David F. DesLauriers

WITNESS:

David F. DesLauriers

STF 1.003

Background: Please address how rate design (such as TOU) and/or demand management options are evaluated compared to generation and transmission options.

RESPONSE:

TEP evaluates demand management options or programs using a battery of costs test that compare the demand management options with the generation and transmission options/costs. Consistent with Decision No. 71819 (Electric Energy Efficiency Standard), the screening test is the societal cost test.

The societal cost test evaluates the benefits of the avoided supply costs of energy and demand, through the reduction in transmission and generation, valued at marginal costs for the periods when there is a load reduction due to the demand management program. The benefits are then compared to the costs of the program. For a more complete explanation of the analysis, please see Mr. Jones' direct testimony exhibit CAJ-7, the Energy Efficiency Resource Plan's Plan of Administration, Attachment A – Cost Effectiveness and Savings Assessment.

While mandated TOU rates (or other rates like super-peak rates, critical-peak rates, real-time pricing, et cetera) contribute to a reduction in systems peak needs, voluntary participation limits that benefit. The primary benefit of TOU rates is the potential reduction in fuel purchased or generated during peak periods. TOU rates are not as effective for peak cost reduction as other load control or demand management options.

RESPONDENT:

Denise Smith

WITNESS:

Craig A. Jones

STF 1.065

Rate Design: Please provide in an Excel worksheet (with all supporting inputs, data sources and information defined) the calculations supporting the changes to customers served under Partial Requirements Service rates. Specifically address the impact on these customers of varying usage levels and varying load factors and/or individual customers on each of the three rates. [Jones Direct 47:15]

RESPONSE:

Mr. Craig A. Jones direct testimony, page 47, lines 14 through 22, describes in detail the changes to the Company's proposed Partial Requirement Service ("PRS") tariffs. The workpaper supporting the new design changes for the PRS schedules are attached as file STF 1.065 TEP PRS Proposed rates.xls. There are currently no customers on any current PRS tariffs; therefore, the Company did not conduct any bill impact schedules for this class.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

	A	B	C	D	E	F	G	H	I
1	PARTIAL REQUIREMENTS TARIFFS								
2									
3	PRS-10								
4									
5			Adjusted Billing						
6			Determinants for Design Change	Proposed Rates	Proposed Revenues		Proposed PRS Rates	SGS Inputed Demand from LR	
7	**Small General Service SGS-10-NEW**							Jan-11	297,496
8	Customer Charge (Single Phase)		215,020	$18.00	$3,870,360.0			Feb-11	324,262
9	Customer Charge (Three Phase)		212,653	$24.00	5,103,672		$20.98	Mar-11	457,989
10	**Summer**							Apr-11	328,315
11	First 500, kWh		74,822,676	$0.0760	5,686,523			May-11	474,000
12	≥ 501 kWh		844,467,249	$0.0980	82,757,790		$35.02	Jun-11	597,542
13	**Winter**							Jul-11	512,830
14	First 500, kWh		105,220,676	$0.0560	5,892,358			Aug-11	440,175
15	≥ 501 kWh		864,013,835	$0.0780	67,393,079			Sep-11	501,218
16	Primary Metering Discount				($4,847.65)		$29.36	Oct-11	461,096
17	**Subtotal Delivery (Margin) Revenue**				**$170,698,935**			Nov-11	338,956
18	PPFAC Summer		919,289,925	$0.033075	30,405,514			Dec-11	288,155
19	PPFAC Winter		969,234,510	$0.030654	29,710,915				5,022,035
20	**TOTAL SGS-10 NEW REVENUE**		**$1,888,524,435**	**$0**	**$230,815,364**				
21	TOTAL SALES								
22									
23	PRS-13								
24									
25			Adjusted Billing						
26			Determinants for Design Change	Proposed Rates	Proposed Revenues				
27	**LARGE GENERAL SERVICE LGS-13-NEW**								
28	Customer Charge		6,420	$900.00	$5,778,000		$900.00		
29	ALL kW		3,277,679	$21.00	68,831,262	(0)			
30	Summer kWh		494,868,791	$0.0036	1,781,528	$28,679,693	$22.30		
31	Winter kWh		550,195,023	$0.0032	1,760,624	$40,151,570	$21.92	$22.08	
32	Priimary Metering Discount				(35,628)				
33	Transformer Owned Discount				(27,317)				
34	**Subtotal Delivery (Margin) Revenue**				**$78,088,470**				
35	**Base Power**				-				
36	Summer kWh		494,868,791	0.033075	16,367,785				
37	Winter kWh		550,195,023	0.030654	16,865,678				
38	**TOTAL LGS-13 REVENUE**				**111,321,933**				
39									
40	PRS-14								
41	**LL&P I-14**								
42	**LARGE LIGHT & POWER SERVICE**								
43	Customer Charge		48	$2,000.00	$96,000.00		$2,000.00		
44	Demand per kW		775,035	$21.00	16,275,730	(0)			
45	Summer kWh		164,577,383	$0.0079	1,300,161	$6,781,554	$25.03		
46	Winter kWh		186,876,897	$0.0069	1,289,451	$9,494,176	$23.85	$24.34	
47	Power Factor Adjustment				-				
48	**Subtotal Delivery (Margin) Revenue**				**$18,961,342**				
49	**Base Power**								
50	Summer kWh		164,577,383	$0.030795	$5,068,161				
51	Winter kWh		186,876,897	$0.028540	5,333,467				
52	**TOTAL GS-43 REVENUE**				**$29,362,969**				

	K	L	M	N	O	P	Q	R
1								
2								
3								
4								
5								
6								
7	GENERAL SERVICE PRS-10 UNBUNDLE				LARGE GENERAL SERVICE PRS-13 UNBUNDLE			
8								
9	CUSTOMER DELIVERY	$5.62			CUSTOMER DELIVERY	$417.18		
10	CUSTOMER METERS	6.55			CUSTOMER METERS	$230.72		
11	CUSTOMER BILLING & COLLECTIONS	7.71			CUSTOMER BILLING & COLLECTIONS	$204.96		
12	CUSTOMER METER READING	1.10			CUSTOMER METER READING	$47.14		
13	Customer Charge ($/month)	$20.98			Customer Charge ($/month)	$900.00		
14								
15	Backup Service				Backup Service			
16	Summer Delivery ($/kW)	$11.63			Summer Delivery ($/kW)	$11.24		
17	Winter Delivery ($/kW)	$5.97			Winter Delivery ($/kW)	$10.86		
18	GenerationCapacity ($/kW)	$18.50			GenerationCapacity ($/kW)	$7.02		
19	Fixed Must Run ($/kW	$1.39			Fixed Must Run ($/kW	$0.92		
20	Transmission ($/kW)	$2.73			Transmission ($/kW)	$2.43		
21	Transmission Ancillary ($/kW)				Transmission Ancillary ($/kW)			
22	System Control & Dispatch	$0.04			System Control & Dispatch	$0.03		
23	Reactive Supply & Voltage Control	$0.15			Reactive Supply & Voltage Control	$0.13		
24	Regulation & Frequency Response	$0.14			Regulation & Frequency Response	$0.13		
25	Spinning Reserve Service	$0.38			Spinning Reserve Service	$0.34		
26	Supplemental Reserve Service	$0.06			Supplemental Reserve Service	$0.06		
27	Supplemental Service				Supplemental Service			
28	Summer Delivery ($/kW)	$5.82			Summer Delivery ($/kW)	$5.62		
29	Winter Delivery ($/kW)	$2.99			Winter Delivery ($/kW)	$5.43		
30	GenerationCapacity ($/kW)	$9.25			GenerationCapacity ($/kW)	$3.51		
31	Fixed Must Run ($/kW	$0.70			Fixed Must Run ($/kW	$0.46		
32	Transmission ($/kW)	$1.37			Transmission ($/kW)	$1.22		
33	Transmission Ancillary ($/kW)				Transmission Ancillary ($/kW)			
34	System Control & Dispatch	$0.02			System Control & Dispatch	$0.02		
35	Reactive Supply & Voltage Control	$0.08			Reactive Supply & Voltage Control	$0.07		
36	Regulation & Frequency Response	$0.07			Regulation & Frequency Response	$0.07		
37	Spinning Reserve Service	$0.19			Spinning Reserve Service	$0.17		
38	Supplemental Reserve Service	$0.03			Supplemental Reserve Service	$0.03		
39								
40	Backup Service				Backup Service			
41	Summer ($/kW)	$35.02	$0.00		Summer ($/kW)	$22.30	($0.00)	
42	Winter ($/kW)	$29.36	$0.00		Winter ($/kW)	$21.92	($0.00)	
43	Supplemental Servic3				Supplemental Servic3			
44	Summer ($/kW)	$17.51	$0.00		Summer ($/kW)	$11.15	($0.00)	
45	Winter ($/kW)	$14.68	$0.00		Winter ($/kW)	$10.96	($0.00)	
46								
47								
48								
49								
50								
51								
52								

	S	T	U
1			
2			
3			
4			
5			
6			
7	LARGE LIGHT & POWER PRS-14 UNBUNDLE		
8			
9	CUSTOMER DELIVERY	$923.66	
10	CUSTOMER METERS	$477.35	
11	CUSTOMER BILLING & COLLECTIONS	$487.16	
12	CUSTOMER METER READING	$111.83	
13	Customer Charge ($/month)	$2,000.00	
14			
15	Backup Service		
16	Summer Delivery ($/kW)	$12.30	
17	Winter Delivery ($/kW)	$11.12	
18	GenerationCapacity ($/kW)	$8.25	
19	Fixed Must Run ($/kW	$1.91	
20	Transmission ($/kW)	$2.00	
21	Transmission Ancillary ($/kW)		
22	System Control & Dispatch	$0.03	
23	Reactive Supply & Voltage Control	$0.11	
24	Regulation & Frequency Response	$0.10	
25	Spinning Reserve Service	$0.28	
26	Supplemental Reserve Service	$0.05	
27	Supplemental Service		
28	Summer Delivery ($/kW)	$6.15	
29	Winter Delivery ($/kW)	$5.56	
30	GenerationCapacity ($/kW)	$4.13	
31	Fixed Must Run ($/kW	$0.96	
32	Transmission ($/kW)	$1.00	
33	Transmission Ancillary ($/kW)		
34	System Control & Dispatch	$0.02	
35	Reactive Supply & Voltage Control	$0.06	
36	Regulation & Frequency Response	$0.05	
37	Spinning Reserve Service	$0.14	
38	Supplemental Reserve Service	$0.03	
39			
40	Backup Service		
41	Summer ($/kW)	$25.03	$0.00
42	Winter ($/kW)	$23.85	($0.00)
43	Supplemental Servic3		
44	Summer ($/kW)	$12.52	$0.00
45	Winter ($/kW)	$11.93	($0.00)
46			
47			
48			
49			
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STF 1.093

Lifeline: Please provide a worksheet with all supporting information that calculates the cost of the Company's existing Lifeline discounts (subsidies) by each rate, rate block and foregone adjustors or other items. [Jones Direct 69:13 and 70:11]

RESPONSE:

Test year totals include $2.512 million (the Commission amount of $2.3 million excludes certain specified components of the discounts) of margin (non-fuel) related subsidies plus approximately $1.759 million of fuel cost related subsidies (on an annualized basis) plus $285,000 of avoided DSM related charges, for a total of $4.556 million of subsidies being paid by the remaining rate payers or the Company. Please see STF 1.093 Lifeline Discount Reports 2011.pdf, Bates Nos. TEP\015059-015070, for available information responsive to the requested discount amounts by rate class.

In addition to the above subsidies, approximately 4 hours each month are spent by pricing personnel to generate compliance reports. A minimum of 20 additional hours are spent each time any rate changes for bill testing and verification.

While the above charges can be quantified, the Company does not track all of the costs associated with each Lifeline Rate separately, nor are any of the costs tracked by rate block. Please see the table below for a partial list of administrative costs associated with the Lifeline Program. The Company does not consider the following list fully representative of the costs associated with monitoring and implementing the Lifeline program since many other man-hours associated with accommodating the Lifeline rates are not tracked separately but simply fall on the shoulders of other rate payers.

Lifeline	
Marketing/Brochures	2011 - $2,155 – reprint of English brochure 2010 - $1,600 – reprint of English brochure 2009 - $6,542 reprints of English and Spanish brochures 3-year average - $3,500
Administration (Applications, master metering reporting, gathering reporting data)	2011 - $47,000
Compliance administration	Average - $2,000
IT administration	Average - $7,200
Lifeline Medical administration (home visits, verification of applications)	Average - $65,000
TOTAL	**$124,700**

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

Tucson Electric Power - Lifeline Discounts

Jan-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$16,577.82	1,389,152
5010	TE5-01	$18,404.38	3,633,530
5016	TE6-01	$133,868.44	13,143,874
5026	TE8-01	$14,846.95	913,048
5008	TE4-21	$39.94	5,896
5012	TE5-21	$40.69	13,144
5017	TE6-21	$264.00	40,413
5027	TE8-21	$104.41	9,571
5009	TE4-70	$46.68	10,689
5013	TE5-70	$90.54	29,160
5022	TE6-70	$1,160.00	144,480
5028	TE8-70	$228.40	23,704
5014	TE5-201A	$2.97	5,100
5015	TE5-201B	$0.00	1,213
5023	TR6-201A	$3,022.01	458,957
5029	TE8-201A	$182.31	21,511
5024	TE6-201B	$112.00	15,429
5032	TE6-01BC	$0.00	-
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$188,991.54**	**19,858,871**
	Federal Reported Numbers	**$210,339.51**	**19,858,871**

228,513,105 KWh x .007696 = $1,758,637
228,513,105 KWh x .001249 = 285,413
2,044,050

ACC 12 mo $2,331,842.19 delivery only
Fed 12 mo 2,511,852.19 delivery plus Cust Chq

Tucson Electric Power - Lifeline Discounts

Feb-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$16,045.63	1,163,463
5010	TE5-01	$19,947.34	2,949,061
5016	TE6-01	$134,318.14	11,087,112
5026	TE8-01	$13,633.45	761,351
5008	TE4-21	$44.33	3,975
5012	TE5-21	$42.86	10,731
5017	TE6-21	$256.00	31,662
5027	TE8-21	$84.09	7,329
5009	TE4-70	$59.03	9,591
5013	TE5-70	$100.18	21,137
5022	TE6-70	$1,151.43	114,439
5028	TE8-70	$221.97	19,432
5014	TE5-201A	$9.98	4,340
5015	TE5-201B	$4.97	851
5023	TR6-201A	$3,044.90	409,365
5029	TE8-201A	$175.87	18,085
5024	TE6-201B	$112.00	12,923
5032	TE6-01BC	$16.00	740
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$189,268.17**	**16,625,587**
	Federal Reported Numbers	**$210,061.10**	**16,625,587**

Tucson Electric Power - Lifeline Discounts

Mar-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$16,417.73	1,003,894
5010	TE5-01	$22,242.16	2,555,745
5016	TE6-01	$144,001.71	10,035,061
5026	TE8-01	$14,057.10	728,192
5008	TE4-21	$52.01	3,694
5012	TE5-21	$67.41	7,965
5017	TE6-21	$288.00	32,179
5027	TE8-21	$139.00	9,336
5009	TE4-70	$77.44	9,452
5013	TE5-70	$120.50	19,659
5022	TE6-70	$1,240.00	104,198
5028	TE8-70	$262.40	22,066
5014	TE5-201A	$8.35	3,780
5015	TE5-201B	$3.62	674
5023	TR6-201A	$3,094.18	345,213
5029	TE8-201A	$245.56	21,759
5024	TE6-201B	$112.00	10,712
5032	TE6-01BC	$32.00	2,160
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$202,461.17**	**14,915,739**
	Federal Reported Numbers	**$224,368.05**	**14,915,739**

Tucson Electric Power - Lifeline Discounts

Apr-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$15,070.60	816,363
5010	TE5-01	$21,978.40	2,268,920
5016	TE6-01	$134,579.35	9,031,204
5026	TE8-01	$12,985.71	666,045
5008	TE4-21	$43.97	2,721
5012	TE5-21	$67.96	7,298
5017	TE6-21	$264.00	25,177
5027	TE8-21	$93.07	6,078
5009	TE4-70	$75.85	5,733
5013	TE5-70	$121.61	17,712
5022	TE6-70	$1,159.27	88,851
5028	TE8-70	$224.55	14,784
5014	TE5-201A	$9.34	3,720
5015	TE5-201B	$4.38	791
5023	TR6-201A	$3,016.00	309,249
5029	TE8-201A	$187.96	16,631
5024	TE6-201B	$112.00	8,376
5032	TE6-01BC	$31.03	1,650
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$190,025.05**	**13,291,303**
	Federal Reported Numbers	**$210,567.82**	**13,291,303**

Tucson Electric Power - Lifeline Discounts

May-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$15,647.42	851,194
5010	TE5-01	$22,137.89	2,497,239
5016	TE6-01	$133,089.50	10,056,933
5026	TE8-01	$14,714.95	769,984
5008	TE4-21	$45.50	3,318
5012	TE5-21	$52.76	9,078
5017	TE6-21	$256.00	25,955
5027	TE8-21	$95.19	6,159
5009	TE4-70	$83.55	6,424
5013	TE5-70	$148.18	20,623
5022	TE6-70	$1,127.97	100,289
5028	TE8-70	$310.49	18,004
5014	TE5-201A	$8.60	4,330
5015	TE5-201B	$3.78	685
5023	TR6-201A	$2,990.83	338,186
5029	TE8-201A	$206.03	17,982
5024	TE6-201B	$112.00	9,414
5032	TE6-01BC	$39.07	2,410
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$191,069.71**	**14,738,207**
	Federal Reported Numbers	**$214,814.97**	**14,738,207**

Tucson Electric Power - Lifeline Discounts

Jun-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$18,159.44	1,167,918
5010	TE5-01	$21,214.01	3,342,542
5016	TE6-01	$138,107.74	14,058,291
5026	TE8-01	$18,549.21	1,075,231
5008	TE4-21	$73.85	5,893
5012	TE5-21	$58.28	13,044
5017	TE6-21	$272.00	33,455
5027	TE8-21	$118.56	7,887
5009	TE4-70	$120.63	10,579
5013	TE5-70	$147.28	30,828
5022	TE6-70	$1,206.15	152,418
5028	TE8-70	$490.75	31,971
5014	TE5-201A	$12.96	5,380
5015	TE5-201B	$5.20	733
5023	TR6-201A	$3,079.26	441,863
5029	TE8-201A	$273.47	22,639
5024	TE6-201B	$120.00	13,258
5032	TE6-01BC	$96.00	9,699
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$202,104.79**	**20,423,629**
	Federal Reported Numbers	**$231,987.27**	**20,423,629**

Tucson Electric Power - Lifeline Discounts

Jul-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$15,831.23	1,567,962
5010	TE5-01	$13,845.69	4,573,379
5016	TE6-01	$121,914.54	18,697,016
5026	TE8-01	$17,382.55	1,368,712
5008	TE4-21	$33.67	8,662
5012	TE5-21	$33.47	18,278
5017	TE6-21	$216.00	37,770
5027	TE8-21	$102.14	7,450
5009	TE4-70	$39.57	11,013
5013	TE5-70	$73.29	37,589
5022	TE6-70	$983.15	182,104
5028	TE8-70	$432.81	33,840
5014	TE5-201A	$7.79	7,770
5015	TE5-201B	$0.00	1,851
5023	TR6-201A	$2,863.63	598,745
5029	TE8-201A	$202.75	23,184
5024	TE6-201B	$104.00	18,508
5032	TE6-01BC	$80.00	11,427
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$174,146.28**	**27,205,260**
	Federal Reported Numbers	**$198,747.92**	**27,205,260**

Tucson Electric Power - Lifeline Discounts

Aug-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$16,723.80	1,493,665
5010	TE5-01	$14,439.93	4,467,801
5016	TE6-01	$144,360.56	20,390,465
5026	TE8-01	$21,347.59	1,549,565
5008	TE4-21	$54.43	9,722
5012	TE5-21	$24.10	15,484
5017	TE6-21	$280.00	52,040
5027	TE8-21	$171.84	12,623
5009	TE4-70	$123.57	14,807
5013	TE5-70	$105.13	38,600
5022	TE6-70	$1,246.37	226,922
5028	TE8-70	$613.93	51,381
5014	TE5-201A	$4.56	6,230
5015	TE5-201B	$0.00	2,180
5023	TR6-201A	$3,096.00	575,322
5029	TE8-201A	$381.81	34,086
5024	TE6-201B	$120.00	18,001
5032	TE6-01BC	$112.00	17,466
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$203,205.62**	**28,976,360**
	Federal Reported Numbers	**$230,946.34**	**28,976,360**

Tucson Electric Power - Lifeline Discounts

Sep-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$13,310.00	1,213,137
5010	TE5-01	$12,312.84	4,017,883
5016	TE6-01	$133,349.22	19,111,209
5026	TE8-01	$19,669.24	1,429,644
5008	TE4-21	$59.18	7,577
5012	TE5-21	$24.37	15,696
5017	TE6-21	$248.00	42,568
5027	TE8-21	$126.12	10,569
5009	TE4-70	$88.18	11,683
5013	TE5-70	$114.62	34,284
5022	TE6-70	$1,080.00	191,682
5028	TE8-70	$561.54	34,287
5014	TE5-201A	$4.64	6,800
5015	TE5-201B	$0.00	2,406
5023	TR6-201A	$3,020.90	601,809
5029	TE8-201A	$229.16	25,750
5024	TE6-201B	$112.00	18,405
5032	TE6-01BC	$96.00	15,428
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$184,406.01**	**26,790,817**
	Federal Reported Numbers	**$208,405.45**	**26,790,817**

Tucson Electric Power - Lifeline Discounts

Oct-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$11,353.72	700,970
5010	TE5-01	$15,112.62	2,501,695
5016	TE6-01	$128,241.99	12,716,551
5026	TE8-01	$17,817.53	994,868
5008	TE4-21	$32.39	3,629
5012	TE5-21	$27.49	6,744
5017	TE6-21	$264.00	32,934
5027	TE8-21	$109.48	7,009
5009	TE4-70	$78.16	6,801
5013	TE5-70	$105.53	22,404
5022	TE6-70	$1,024.00	118,403
5028	TE8-70	$462.09	24,826
5014	TE5-201A	$10.57	4,600
5015	TE5-201B	$0.00	1,793
5023	TR6-201A	$3,016.00	416,731
5029	TE8-201A	$225.31	20,531
5024	TE6-201B	$104.00	12,221
5032	TE6-01BC	$80.00	10,280
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$178,064.88**	**17,602,990**
	Federal Reported Numbers	**$201,016.71**	**17,602,990**

Tucson Electric Power - Lifeline Discounts

Nov-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$8,753.74	475,447
5010	TE5-01	$14,456.32	1,635,500
5016	TE6-01	$125,815.22	9,817,957
5026	TE8-01	$14,953.32	768,849
5008	TE4-21	$40.14	3,111
5012	TE5-21	$31.43	4,446
5017	TE6-21	$240.00	26,325
5027	TE8-21	$82.00	5,829
5009	TE4-70	$79.18	5,365
5013	TE5-70	$129.66	17,721
5022	TE6-70	$1,056.00	101,683
5028	TE8-70	$319.16	17,362
5014	TE5-201A	$8.70	4,050
5015	TE5-201B	$0.00	1,020
5023	TR6-201A	$3,006.96	340,974
5029	TE8-201A	$163.65	14,730
5024	TE6-201B	$112.00	10,723
5032	TE6-01BC	$88.00	9,271
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$169,335.48**	**13,260,363**
	Federal Reported Numbers	**$187,657.70**	**13,260,363**

Tucson Electric Power - Lifeline Discounts

Dec-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$7,892.06	560,287
5010	TE5-01	$10,872.69	1,566,188
5016	TE6-01	$128,969.17	11,200,690
5026	TE8-01	$15,231.67	866,015
5008	TE4-21	$46.03	4,130
5012	TE5-21	$14.61	3,156
5017	TE6-21	$248.00	33,862
5027	TE8-21	$129.01	9,609
5009	TE4-70	$41.09	5,655
5013	TE5-70	$77.69	18,522
5022	TE6-70	$1,080.00	115,281
5028	TE8-70	$301.30	24,391
5014	TE5-201A	$9.21	4,030
5015	TE5-201B	$4.42	933
5023	TR6-201A	$2,943.49	370,482
5029	TE8-201A	$188.59	18,420
5024	TE6-201B	$112.00	11,334
5032	TE6-01BC	$112.00	10,994
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$168,273.03**	**14,823,979**
	Federal Reported Numbers	**$182,939.35**	**14,823,979**

STF 1.094

Lifeline: Please provide a worksheet with all supporting information that calculates the cost of the Company's proposed Lifeline discounts (subsidies) by each rate, rate block and forgone adjustors or other items. [Jones Direct 69:13 and 70:11]

RESPONSE:

There will still be personnel costs associated with providing the Lifeline subsidies, but the Company has not attempted to quantify the total hours saved. As the rates become easier to explain and less confusing, less time will be needed modifying the billing system, testing new rates, developing complex data gathering programs for reporting purposes, speaking with customers, and training personnel. As the rates become less complicated and less time is required of the Company's personnel, the time and efforts will be redirected to additional or enhanced service to the customers.

The actual amount of subsidy built into the current rates is approximately the same as in the existing test year, except it is about 14% higher to reflect the 14% increase in residential rates. The new total can be found on lines 40 and 41 of the summary page of the file provided in the revised response to UDR 1.1 dated August 17, 2012, labeled 6. 2012 TEP Proposed Rates-Corrected, and total $2,605,960.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY
SUMMARY PROPOSED REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

-5,924,009

Line No.	Rate Class	Adjusted Customers	Adjusted Sales (kWh)	Margin Revenue	Purchase Power & Fuel	Test Year Adjusted Revenue	Proposed Revenues: Margin Revenue ($)	Proposed Revenues: Purchase Power & Fuel	Proposed Revenues: Total Revenues
1	Proposed Increased								
2									
3									
4	Residential Service	360,521	3,699,107,059	$241,095,410	$111,635,462	$352,730,872	$292,058,299	$118,425,580	$410,483,879
5	Residential Time Of Use	8,873	129,923,963	7,043,984	3,797,665	10,841,649	8,741,564	4,388,547	13,130,111
6	Small General Service	35,978	1,947,489,380	156,798,459	55,398,880	212,197,338	173,512,315	62,017,156	235,529,471
7	Small General Service Time of Use	924	123,590,519	8,103,358	3,384,976	11,488,333	10,007,939	4,109,476	14,117,415
8	Irrigation & Water Pumping	484	107,584,687	4,446,839	2,908,651	7,355,490	5,424,053	3,248,547	8,672,601
9	Large General Service	536	1,046,539,305	55,085,198	30,598,384	85,683,582	83,968,872	33,283,559	117,252,430
10	Large General Service Time of Use	87	216,614,667	8,424,561	6,579,663	15,004,224	10,264,013	7,163,697	17,427,710
11	Large Light & Power Service	4	351,454,280	12,469,651	10,271,504	22,741,155	19,347,941	10,401,627	29,749,569
12	Large Light & Power Service Time of Use	9	542,786,937	17,883,872	13,900,001	31,783,872	22,816,280	16,041,271	38,857,551
13	Mining Service	2	1,083,071,404	30,374,675	29,264,219	59,638,894	42,277,383	31,928,918	74,206,301
14	Traffic Signals & Lighting Service	19,566	37,430,789	3,022,183	913,817	3,936,000	4,089,559	1,181,323	5,270,882
15	TOTAL	426,985	9,285,592,991	$544,748,189	$268,653,221	$813,401,411	$672,508,219	$292,189,701	$964,697,920
16									
17	Rate Schedule								
18	R-01 - Lifeline	19,858	190,498,193	$11,801,193	$5,712,319	$17,513,513	$15,284,739	$6,066,433	$21,351,173
20	R-01	327,921	3,364,805,199	223,461,936	102,007,849	325,469,785	269,512,527	107,542,327	377,054,854
21	R-02	1,985	3,727,106	185,953	109,756	295,709	231,353	117,461	348,815
22	R-201AF	4,943	69,035,331	3,588,889	2,061,241	5,650,130	4,784,167	2,196,272	6,980,440
19	R-201AF - Lifeline	352	4,797,453	235,965	143,480	379,445	333,717	152,620	486,337
23	R-201AN	5,462	62,392,149	3,306,229	1,927,235	5,233,464	4,483,748	1,987,709	6,471,457
24	**TOTAL RESIDENTIAL SERVICE**	**360,521**	**3,695,255,432**	**$242,580,166**	**$111,961,880**	**$354,542,046**	**$294,630,252**	**$118,062,823**	**$412,693,075**
25									
26	R-21F - Lifeline	51	601,680	$27,889	$17,837	$45,726	$42,235	$20,218	$62,453
27	R-70F - Lifeline	198	2,036,942	114,504	59,014	173,519	148,184	68,605	216,789
28	R-201BF - Lifeline	13	151,418	6,684	4,342	11,025	9,869	5,086	14,955
29	R-21F	2,411	40,511,249	1,929,952	1,222,077	3,152,029	2,687,368	1,367,656	4,055,023
30	R-70F	4,110	59,486,521	3,441,136	1,722,450	5,163,586	4,065,192	2,011,789	6,076,981
31	R-70N-B	202	2,721,591	179,745	80,748	260,493	188,692	92,078	280,770
32	R-70N-C	651	7,853,166	519,667	232,140	751,807	556,479	265,638	822,117
33	R-70N-D	452	5,786,727	382,164	171,439	553,603	405,243	195,779	601,022
34	R-201BF	494	7,561,541	333,854	214,871	548,725	462,088	253,954	716,041
35	R-201CF	205	2,211,821	103,121	66,786	169,907	145,393	74,107	219,500
36	R-201BN	58	847,816	39,443	25,350	64,793	52,370	28,495	80,864
37	R-201CN	27	153,489	7,999	4,773	12,772	12,459	5,143	17,601
38	**TOTAL RESIDENTIAL TOU SERVICE**	**8,873**	**129,923,963**	**$7,086,159**	**$3,821,825**	**$10,907,984**	**$8,775,571**	**$4,388,547**	**$13,164,118**
39									
40	Total Lifeline Discount Non-TOU			-1,484,756	-689,175	-2,173,931	-2,571,953		-2,571,953
41	Total Lifeline Discount TOU			-42,175	-24,160	-66,335	-34,007		-34,007
42	R-01 Community Solar		3,851,627	0	362,757	362,757		362,757	362,757
43	**TOTAL RESIDENTIAL SERVICE**	**369,394**	**3,829,031,022**	**$248,139,394**	**$115,433,127**	**$363,572,522**	**$300,799,863**	**$122,814,127**	**$423,613,990**

Robin Mitchell

From: howard@energytactics.com
Sent: Wednesday, January 09, 2013 2:16 PM
To: Robin Mitchell
Subject: Fwd: Exhibit 15 Part 4 of 4

Footnote 67 10/8

Begin forwarded message:

From: "howard@energytactics.com" <howard@energytactics.com>
Subject: Fwd: Exhibit 15 Part 4 of 4
Date: November 13, 2012 2:38:34 PM EST
To: Tracy Klaes <tklaes@blueridgecs.com>

The PRS footnote

Begin forwarded message:

From: <jbryne@TEP.Com>
Subject: RE: Exhibit 15 Part 4 of 4
Date: October 8, 2012 12:20:05 PM EDT
To: <howard@energytactics.com>

No they are not. Hopefully you just decided to take today off for Columbus' sake.

Jessica Bryne
Regulatory Services
(520) 884-3680

-----Original Message-----
From: howard@energytactics.com [mailto:howard@energytactics.com]
Sent: Friday, October 05, 2012 6:50 PM
To: Bryne, Jessica
Subject: Re: Exhibit 15 Part 4 of 4

Jessica

when I worked at Atlantic Electric we never got Columbus day off either. On the other hand the folks at the DC Commission this week were looking forward to their day off. As for me since I work for my self and have a home office just about anythings goes for Monday

Enjoy

BTW are the definitions specified anywhere in the tariff?

Regards

Howard

On Oct 5, 2012, at 8:23 PM, <jbryne@TEP.Com> wrote:

Howard,

Thanks for the well wishes, but I don't get that holiday off! Unbelievable I know. I hope you have a good one though.

Below are the definitions you requested in your meeting with Craig and Brenda.

Determination of Supplemental Service

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by the Customer's generation facility.

Back-up/Standby Energy

Back-up energy shall be defined to be electric energy supplied by Company to replace power ordinarily generated by Customer's generation facility during unscheduled full and partial outages of said facility.

-Jessica

-----Original Message-----

From: howard@energytactics.com [mailto:howard@energytactics.com]

Sent: Friday, October 05, 2012 12:01 PM

To: Bryne, Jessica

Subject: Re: Exhibit 15 Part 4 of 4

Enjoy the holiday weekend!

On Oct 5, 2012, at 2:59 PM, <jbryne@TEP.Com> wrote:

Great thanks. I think I owe you a few more items, I will try to get them to you as soon as I can.

Jessica Bryne
Regulatory Services
(520) 884-3680

-----Original Message-----
From: howard@energytactics.com [mailto:howard@energytactics.com]
Sent: Friday, October 05, 2012 11:59 AM
To: Bryne, Jessica
Subject: Exhibit 15 Part 4 of 4

Part 4

Robin Mitchell

From: howard@energytactics.com
Sent: Wednesday, January 09, 2013 2:25 PM
To: Robin Mitchell
Subject: Fwd: TEP Water Pumping

Footnote 54 10/23

Last of Three

Begin forwarded message:

From: "howard@energytactics.com" <howard@energytactics.com>
Subject: Re: TEP Water Pumping
Date: October 23, 2012 6:05:08 PM EDT
To: <CJones@tep.com>
Cc: <BPries@tep.com>

Craig

Thank you for the quick response

regards

Howard

On Oct 23, 2012, at 5:27 PM, <CJones@tep.com> wrote:

Hi Howard,

Here are our responses to the water pumping questions you had this morning. As always feel free to follow up if you have additional questions.

Thanks.

Craig

> **From:** "howard@energytactics.com" <howard@energytactics.com>
> **Date:** October 23, 2012, 8:46:17 AM MST
> **To:** <CJones@tep.com>
> **Subject: TEP Water Pumping**

Craig

Schedule H-2-1 shows Interruptible Agricultural Pumping as being moved to Proposed Rate Schedule GS-43 and Municipal Water Pumping to GS-43. **Correct.**

Schedule H-2-2 shows Interruptible Agricultural Pumping as being moved to Proposed Rate Schedule GS-31 and Municipal Water Pumping to PS-43, 45. **The labeling should read Interruptible Agricultural Pumping proposed rate GS-43 and Municipal Pumping to GS-43.**

Can I presume that that Schedule H2-2 is incorrect? **Labels are incorrect in H2-2 and should be changed to reflect GS-43 as mentioned above.**

Your testimony includes Original Sheet No. 801 - Rate: GS-43 Water Pumping Service, but no PS-43, 45 or GS - 31. **This is correct, PS-43 and GS-31 are combined into the GS-43 rate proposed and will be applicable to all water pumping customers including the City of Tucson Water Utility and private water companies.**

However this Rate is available "...to the City of Tucson Water Utility and private water Companies..."

Questions
1- Are Interruptible Agricultural Pumping customers to be served on Rate GS-43? **Yes.**

2- Are there any minimum demand or minimum bills for these customers. **These minimum requirements are not in the current rates and were not proposed in this application.**

3 - Why is there no demand charges for this Rate? **None of these rates currently have a demand component and one was not proposed in this filing in lieu of all other changes.**

4 - For new customers on this rate will there be any analysis of construction costs versus expected or minimum revenue? **Yes, the existing line extension rules will be used to determine any customer contribution needed to make the addition of the new customer economically feasible.**

5 - Does any CIAC or other profitability test apply? **Yes, if required by the line extension policy.**

Regards

Howard

STF 1.096

Lifeline: Please explain why a customer must be requalified for the proposed Lifeline rate if they move from one service location to another? [Jones Direct 72:4]

RESPONSE:

In order to maintain accurate, up to date information on its customers, the Company requires Lifeline rate customers to re-qualify upon change of location. The financial status of a consumer periodically changes. A change of location can indicate a change in status; therefore, it provides an optimal time to verify if the consumer still qualifies for a discounted rate. In addition, the Company is obligated to its customers and to the Commission to ensure oversight of discount-rate programs.

RESPONDENT:

Lindy Sheehey

WITNESS:

Lindy Sheehey

STF 1.097

Lifeline: Please provide a narrative describing the requirements for the annual requalification for the proposed Lifeline rate for low-income, senior and/or medical. [Jones Direct 72:10]

RESPONSE:

On an annual basis, the Company mails a letter requesting Lifeline, low-income, senior and/or medical customers to re-qualify for special programs.

The Company's billing system provides a list of customers with special programs and/or discounts. Letters are manually generated and mailed to customers. Customers have up to 4 weeks to respond and provide the Company with an updated application.

This exercise allows the Company to maintain accurate records and provide discount programs to those who qualify, reduce fraud, remove discounts from accounts where the customer is deceased, and, if a customer is deceased, the process allows the Company to identify a potential change in consumer and update records.

The Company is obligated to its customers and to the Commission to ensure oversight of discount-rate programs.

RESPONDENT:

Lindy Sheehey

WITNESS:

Lindy Sheehey

STF 1.100

Miscellaneous Service Fees: Please provide an Excel worksheet and supporting information including determinants for each fee to support the existing value of $2,617,926. [Jones Direct 74:9]

RESPONSE:

Please see Income – Service Fees Late Fees.xlsm provided in the revised response to UDR 1.1 dated August 17, 2012, for the Company proposed changes to miscellaneous service fees.

RESPONDENT:

Pricing (Ashley Leschak)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2010

ADJUSTMENT NAME	Misc Service Revenues - Service & Late Fees
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	March 7, 2012
PREPARED BY:	Ashley Leschak
CHECKED BY:	Brenda Pries
REVIEWED BY:	Craig Jones

		Total Company		ACC Jurisdictional	
FERC ACCT	**FERC ACCOUNT DESCRIPTION**	**DEBIT**	**CREDIT**	**DEBIT**	**CREDIT**
451	Miscellaneous Service Revenues		$1,109,816		$1,109,816
	ENTRY TOTAL	**$0**	**$1,109,816**	**$0**	**$1,109,816**

Reason for Adjustment

To increase Miscellaneous Service Revenues (FERC 451) due to an increase to fees.

TUCSON ELECTRIC POWER COMPANY
SERVICE FEE ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2010

Line	SERVICE REVENUES	TY Fees	TY Revenue	Units	Proposed Fees	TY Revenue Impact
1	Establishment/Re-establishment of Service, service read only	$13.50	$1,557,576	115,376	$20.00	$749,944
2	-Regular Working Hours					
3	Establishment of Service Connect or Reconnect under usual operating procedures	$22.00	$699,235	31,783	$32.00	$317,834
4	-Regular Working Hours					
5	Establishment of Service Connect or Reconnect under usual operating procedures	$51.00	$297,483	5,833	$57.00	$34,998
6	-all hours other then Regular Working Hours					
7	Establishment of Service Connect or Reconnect under usual operating procedures	$71.00	$45,156	636	$78.00	$4,452
8	-Regular Working Hours - Three Phase Metering					
9	Establishment of Service Connect or Reconnect under usual operating procedures	$198.00	$16,830	85	$216.00	$1,530
10	-all hours other then Regular Working Hours - Three Phase Metering					
11	Customer Requested Meter Rereads (Includes Out of Cycle Reads)	$13.00	$494	38	$32.00	$722
12	Late Fee	1.5%			1.5%	$0
13	Metering Field Test	$144.00	$1,152	8	$186.00	$336
14	**TOTAL TY ACTIVITY AND ADJUSTMENT TO SERVICE REVENUES**		$2,617,926			**$1,109,816**

1/10/2013 2:54 PM

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ACTIVITY - SERVICE FEES

CIS+	CC&B	Description	UNITS	Fee
	CONNECT	Connect Fee	27,617	$22.00
RES1	SC	Service Establishment Fee	112,317	$13.50
RECRS1	RCON	Reconnect Fee	4,166	$22.00
		Residential	**144,100**	
RECRSP	PREMRC	Premium (after hours) Reconnect F	5,809	$51.00
RECRSM	SPLMT	Special Reconnect Fee	-	$35.00
RECRST	SPECRC	Special Reconnect Fee	109	$150.00
RES1SP	SPECSC	Special Service Establishment Fee	7	$150.00
		Residential	**5,925**	
	CONNECT	Connect Fee	611	$71.00
RECGS1	RCON3	Reconnect Fee	25	$71.00
RECRSP	PREMRC	Premium (after hours) Reconnect F	84	$198.00
GS1	SC	Service Establishment Fee	3,059	$13.50
		Commercial	**3,779**	
GSP	PREMSC	Premium Connect Fee	24	$51.00
RECGSP	SPLMT	Premium Reconnect Fee	-	$35.00
RESP	PREMSC3	Premium (after hours) Connect Fee	1	$198.00
		Commercial	**25**	
REREAD	REREAD	Meter Reread Service Charge	38	$13.00
MTRTST	MTRTST	Meter Test Charge	8	$144.00

Data provided by CC&B

TUCSON ELECTRIC POWER COMPANY
METER REREADS & TESTING ACTIVITY

Customer Requested Rereads							XREREAD	**Current Rate**		
Single Phase Tech	$31.59	per read		0.50	read	$15.80				
TEP Supplied Vehicle	$4.87	per read		1.00	read	$4.87				
Call Center Representative	$4.28	per call	x	1.00	No. of calls =	$4.28				
Total Material			$0.00							
Total labor			$24.95							
Total Direct (Material & Labor)			$24.95							
Labor Overhead	0.00% x Labor						$0.00			
Materials Overhead	4.54% x Material						$0.00			
E&S	15.68% x (T.D. +O.H.)						$3.91			
A&G	12.07% x (T.D. + ENG. + O.H.)						$3.48			
Total Cost							**$32.35**	$13.00	($19.35)	**$32.00**
Meter Field Testing							XMTRTST			
Journeyman Metering Technician	$38.50	per hr.	x	2.00	hrs. =	$77.00				
Metering Services Scheduling Coordinato	$30.92	per hr.	x	0.33	hrs. =	$10.20				
Call Center Representative	$4.28	per call	x	1.00	No. of calls =	$4.28				
Total Material			$0.00							
Total labor			$87.20							
Total Direct (Material & Labor)			$87.20							
Labor Overhead	60.6% x Labor						$52.86			
Materials Overhead	0.00% x Material						$0.00			
E&S	15.68% x (T.D. +O.H.)						$21.97			
A&G	12.07% x (T.D. + ENG. + O.H.)						$19.56			
Total Cost							**$185.87**	$144.00	($41.87)	**$186.00**

TUCSON ELECTRIC POWER COMPANY
SERIVCE ESTABLISHMENT ACTIVITY

	Rate / Basis	Quantity	Subtotal	Amount	Code	2011 calc	Current Rate	net change	Proposed Charge
Service Establishment/Reestablishment - Service Reads Only (SES)					XSC				
SES Contract Fee	$6.00 per read	1.00 read		$6.00					
TEP Supplied Vehicle	$4.87 per read	1.00 read		$4.87					
Call Center Representative	$4.28 per call x	1.00 No. of calls =		$4.28					
Total Material			$0.00						
Total labor			$15.15						
Total Direct (Material & Labor)			$15.15						
Labor Overhead	0.00% x Labor					$0.00			
Materials Overhead	4.54% x Material					$0.00			
E&S	15.68% x (T.D. +O.H.)					$2.38			
A&G	12.07% x (T.D. + ENG. + O.H.)					$2.12			
Total Cost						**$19.64**	$13.50	($6.14)	**$20.00**
Service Connect and Reconnect during regular working hours - Single Phase					XRCON				
Single Phase Metering Tech	$31.59 per hr. x	0.50 hrs. =		$15.80	XCONNECT				
SES Administration	$27.14 per hr. x	0.10 hrs. =		$2.71					
TEP Call Center Representative	$4.28 per call x	1.00 No. of calls =		$4.28					
TEP Supplied Vehicle	$4.87 per read x	0.50 per connect		$2.44					
Other direct Charges			$6.72						
Total labor			$18.51						
Total Direct (Material & Labor)			$25.23						
Benefits	0.00% x Labor					$0.00			
PR FICA,FUTA,SUTA	4.54% x Labor					$0.84			
Workers Comp	15.68% x Labor					$2.90			
A&G	12.07% x (T.D. + ENG. + O.H.)					$2.58			
Total Cost						**$31.55**	$22.00	($9.55)	**$32.00**
Service Connect and Reconnect all hours excluding regular working hours - Single Phase					XPREMSC				
Single Phase Metering Tech	$31.59 per hr. x	1.00 hrs. =		$31.59	XPREMRC				
SES Administration	$27.14 per hr. x	0.15 hrs. =		$4.07					
Call Center Representative	$4.28 per call x	1.00 No. of calls =		$4.28					
TEP Supplied Vehicle	$4.87 per read x	1.00 per connect		$4.87					
Other direct Charges			$9.15						

TUCSON ELECTRIC POWER COMPANY
SERIVCE ESTABLISHMENT ACTIVITY

			2011 calc	Current Rate	net change	Proposed Charge
Total labor		$35.66				
Total Direct (Material & Labor)		$44.81				
Benefits	0.00% x Labor		$0.00			
PR FICA,FUTA,SUTA	4.54% x Material		$1.62			
Workers Comp	15.68% x (T.D. +O.H.)		$5.59			
A&G	12.07% x (T.D. + ENG. + O.H.)		$4.98			
Total Cost			**$57.00**	$51.00	($6.00)	**$57.00**

TUCSON ELECTRIC POWER COMPANY
SERIVCE ESTABLISHMENT ACTIVITY

					2011 calc	Current Rate	net change	Proposed Charg
Service Establishment and Reestablishment regular working hours - Three Phase								
Metering Journeyman	$33.15 per hr. x	1.00 hrs. =	$33.15					
Metering Services Scheduling Coordinato	$22.26 per hr. x	0.10 hrs. =	$2.23					
Call Center Representative	$4.28 per call x	1.00 No. of calls =	$4.28					
Total Material		$0.00						
Total labor		$35.38						
Total Direct (Material & Labor)		$35.38						
Labor Overhead	60.6% x Labor				$21.45			
Materials Overhead	4.54% x Material				$0.00			
E&S	15.68% x (T.D. +O.H.)				$8.91			
A&G	12.07% x (T.D. + ENG. + O.H.)				$7.94			
Total Cost					**$77.96**	$71.00	($6.96)	**$78.00**
Service Establishment and Reestablishment all hours excluding regular working hours - Three Phase (Metering/Trou						XSPECRC		
Metering Journeyman	$49.73 per hr. x	2.00 hrs. =	$99.45			XSPECSC		
Metering Services Scheduling Coordinato	$22.26 per hr. x	0.10 hrs. =	$2.23					
Call Center Representative	$4.28 per call x	1.00 No. of calls =	$4.28					
Total Material		$0.00						
Total labor		$101.68						
Total Direct (Material & Labor)		$101.68						
Labor Overhead	60.6% x Labor				$61.64			
Materials Overhead	0.00% x Material				$0.00			
E&S	15.68% x (T.D. +O.H.)				$25.61			
A&G	12.07% x (T.D. + ENG. + O.H.)				$22.81			
Total Cost					**$216.02**	$198.00	($18.02)	**$216.00**

EXHIBIT HS-7 HAS BEEN REDACTED DUE TO CONFIDENTIAL INFORMATION