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BEFORE THE ARIZONA CORPORATION

COMMISSIONERS
BOB STUMP - Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

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 DIRECT TESTIMONY IN SUPPORT OF SETTLEMENT AGREEMENT**

The Utilities Division Staff ("Staff") of Arizona Corporation Commission ("Commission") hereby files the Direct Testimony of Steven M. Olea and Howard S. Solganick in support of the Settlement Agreement in the above-referenced matter.

RESPECTFULLY SUBMITTED this 15th day of February, 2013.

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BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
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Commissioner
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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

TESTIMONY

IN SUPPORT OF

THE SETTLEMENT AGREEMENT

STEVEN M. OLEA

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 15, 2013

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

Mr. Olea's testimony supports the adoption of the Settlement Agreement ("Agreement") as proposed by the Signatories in this case. This testimony describes the settlement process as open, candid, transparent and inclusive of all Signatories to this case. Mr. Olea explains why Staff believes this Agreement is in the public interest.

Mr. Olea's testimony recommends that the Commission adopt the Agreement as proposed.

SECTION I - INTRODUCTION

Q. Please state your name and business address.

A. Steven M. Olea, 1200 West Washington, Phoenix, Arizona, 85007.

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

A. I am employed by the Arizona Corporation Commission ("Commission") as the Director of the Utilities Division ("Staff").

Q. Please state your educational background.

A. I graduated from Arizona State University ("ASU") in 1976 with a Bachelors Degree in Civil Engineering. From 1976 to 1978 I obtained 47 graduate hours of credit in Environmental Engineering at ASU.

Q. Please state your pertinent work experience.

A. From April 1978 to October 1978, I worked for the Engineering Services Section of the Bureau of Air Quality Control in the Arizona Department of Health Services ("ADHS"). My responsibilities were to inspect air pollution sources to determine compliance with ADHS rules and regulations.

From November 1978 to July 1982, I was with the Technical Review Unit of the Bureau of Water Quality Control ("BWQC") in ADHS (this is now part of the Arizona Department of Environmental Quality ["ADEQ"]). My responsibilities were to review water and wastewater construction plans for compliance with ADHS rules, regulations, and Engineering Bulletins.

From July 1982 to August 1983, I was with the Central Regional Office, BWQC, ADHS. My responsibilities were to conduct construction inspections of water and wastewater facilities to determine compliance with plans approved by the Technical Review Unit. I also performed routine operation and maintenance inspections to determine compliance with ADHS rules and regulations, and compliance with United States Environmental Protection Agency requirements.

From August 1983 to August 1986, I was a Utilities Consultant/Water-Wastewater Engineer with the Division. My responsibilities were to provide engineering analyses of Commission regulated water and wastewater utilities for rate cases, financing cases, and consumer complaint cases. I also provided testimony at hearings for those cases.

From August 1986 to August 1990, I was the Engineering Supervisor for the Division. My primary responsibility was to oversee the activities of the Engineering Section, which included one technician and eight Utilities Consultants. The Utilities Consultants included one Telecommunications Engineer, three Electrical Engineers, and four Water-Wastewater Engineers. I also assisted the Chief Engineer and performed some of the same tasks as I did as a Utilities Consultant.

In August 1990, I was promoted to the position of Chief Engineer. My duties were somewhat the same as when I was the Engineering Supervisor, except that now I was less involved with the day-to-day supervision of the Engineering Staff and more involved with the administrative and policy aspects of the Engineering Section.

In April 2000, I was promoted to the position of one of two Assistant Directors of the Division. In this position, I assisted the Division Director in the policy aspects of the Division. I was primarily responsible for matters dealing with water and energy.

In August 2009, I was promoted to my present position as Director of the Utilities Division. In this position, I manage the day-to-day operations of the Utilities Division with the assistance of the Utilities Division Assistant Directors and oversee the management of the Division's Telecom & Energy Section, the Financial & Regulatory Analysis Section, the Consumer Services Section, the Engineering Section and the Administrative Section. In addition, I am responsible for making policy decisions for the Division.

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

A. The purpose of my testimony is to support the Proposed Settlement Agreement ("Agreement"). I will also provide testimony which addresses the settlement process, public interest benefits and general policy considerations.

Q. Did you participate in the negotiations that led to the execution of the Agreement?

A. Yes, I did.

Q. How is your testimony being presented?

A. My testimony is organized into six sections. Section I is this introduction, Section II provides discussion of the settlement process, Section III discusses the various parts of the Agreement, Section IV is a response to a letter from Commissioner Pierce, Section V identifies and discusses the reasons why the Agreement is in the public interest and Section VI addresses general policy considerations.

Q. Will there be other Staff witnesses providing testimony in this case?

A. Yes. Howard Solganick will be providing testimony to discuss rate design and the Lost Cost Fixed Recovery Mechanism.

SECTION II – SETTLEMENT PROCESS

Q. Please discuss the settlement process.

A. The settlement process was open, transparent and inclusive. All parties received notice of the settlement meetings and were accorded an opportunity to raise, discuss, and propose resolutions to any issue that they desired.

Q. Who participated in those meetings?

A. The following parties were participants in some or all of the meetings: Tucson Electric Power Company ("TEP" or "Company"); the Residential Utility Consumer Office ("RUCO"); the Arizona Investment Council ("AIC"); the Southwest Energy Efficiency Project ("SWEEP"), Cynthia Zwick, Arizona Public Service Company ("APS"), the Department of Defense on behalf of Federal Executive Agencies ("DoD"), Kroger Co. ("Kroger"), Freeport-McMoRan Copper & Gold Inc. ("Freeport-McMoRan"), Arizonans for Electric Choice and Competition ("AECC"), IBEW Local 1116 ("IBEW"), Southern Arizona Homebuilders Association ("SAHBA"), Southern Arizona Water Users Association ("SAWUA"), the Sierra Club ("Sierra"), Opower, Inc. ("Opower") Solar Energy Industries Association ("SEIA"), Arizona Solar Energy Industries Association ("AriSEIA"), EnerNOC, Inc. ("EnerNoc"), Vote Solar Initiative ("VSI") and Staff.

Q. Could you identify some of the diverse interests that were involved in this process?

A. Yes. The diverse interests included Staff, RUCO, TEP, investment council, consumer representatives, demand-side management ("DSM")/energy efficiency advocates, low-income consumer advocates, renewable energy advocates, realtors, labor unions, large/industrial users, competitive power producers and the mines.

Q. Were there parties who chose not to execute the Agreement?

A. Yes. The Agreement was signed by all participants with the exception of SWEEP, APS and the Sierra Club.

Q. Was there an opportunity for all issues to be discussed and considered?

A. Yes, each party had the opportunity to raise and have its issues considered.

Q. Were the Signatories able to resolve all issues?

A. Yes, the Signatories were able to resolve and reach agreement on all issues.

Q. How would you describe the negotiations?

A. I believe that all participants zealously advocated and represented their interests. I would characterize the discussions as candid but professional. While acknowledging that not all participants executed the Agreement, I must re-emphasize that all participants had the opportunity to be heard and to have their issues fairly considered.

Q. Would you describe the process as requiring give and take?

A. Yes, I would. As a result of the varied interests represented in the settlement process, a willingness to compromise was necessary. As evidenced in the Agreement, the Signatories compromised on what could be described as vastly different litigation positions.

Q. Because of such compromising, do you believe the public interest was compromised?

A. No. As I will discuss later in this testimony, I believe that the compromises made by the Signatories further the public interest.

Q. Mr. Olea, you have indicated that the Agreement incorporates diverse interests including those of low-income customers, residential customers, large commercial/industrial customers, energy efficiency advocates, renewable energy advocates, the Company and the investment community. Please discuss how the Agreement addresses the diverse interests of these entities.

A. In the Agreement, there are specific provisions which address many of the concerns expressed by the various interests. For example, Sections VII and VIII, which address the interests of those concerned about promoting energy efficiency at any level or pace set by this Commission. Section IX addresses the Environmental Compliance Adjustor surcharge. Section X of the Settlement Agreement addresses Springville Unit 1. Section XI addresses the TEP energy procurement program. Section XII addresses the low-income customer issues. Section XIII addresses the Nogales Transmission Line, Section XIV addresses the San Juan thermal event (fire), Section XVIII addresses quality of service and Section XX addresses four issues raised by RUCO.

Q. What is the revenue increase and cost of equity requested by the Company?

A. TEP requested a net increase in non-fuel base rates of $128 million, which included a requested cost of equity of 10.75 percent.

Q. What is the revenue increase and cost of equity recommended by the settling Signatories?

A. The settling Signatories recommend a non-fuel base rate increase of approximately $76 million, which includes a 10.0 percent cost of equity.

SECTION III – AGREEMENT

Q. Mr. Olea can you please describe Part II of the Agreement?

A. Part II describes the recommended rate increase agreed to by the Signatories. In its application, TEP requested a non-fuel base rate increase of approximately $128 million; however, the Signatories agreed to an increase of approximately $76 million, which is $52 million less than the Company requested. In addition, the Signatories agreed to and recommended a base fuel rate be set for TEP in order to accord them the opportunity to recover $300,252,951, which result in an annual fuel increase of $31,599,730.

Q. Please describe Section III of the Agreement?

A. When the rates of this Agreement become effective, the monthly bill for a residential customer, using the annual average of 767 kilowatt-hour ("kWh") per month, will experience a first year increase of less than $3.00, which will include a rate reduction in the Purchased Power and Fuel Adjustment Clause ("PPFAC") and DSM Surcharge.[1]

Q. Please describe Section IV of the Agreement.

A. A capital structure comprised of 55.97 percent long-term debt, 0.53 percent short-term debt and 43.50 percent common equity is proposed. In addition, the Signatories recommended a return on common equity of 10 percent, an embedded cost of long-term debt of 5.18 percent and a cost of short-term debt of 1.42 percent. Also, the Signatories

[1] This includes the PPFAC and the DSM surcharge but does not include the REST surcharge, taxes or assessments.

proposed a fair value rate of return of 5.05 percent which includes a 0.68 percent rate of return on the fair value increment of rate base.

Q. Please describe Section V of the Agreement.

A. Signatories to the Agreement recommend the adoption of the depreciation and amortization rates proposed by TEP.

Q. Can you please describe Section VI of the Agreement?

A. Yes. This section deals with the Company's PPFAC. The Signatories agreed that the average retail base fuel rate shall be set at $0.032335 per kWh. This section also addresses the following:

- A one-time $3 million credit related to previous sulfur credits;
- A deferral of costs related to the San Juan thermal event, which is discussed in detail in Part XIV;
- Pursuant to the plan of administration, the Signatories agreed that the PPFAC will be modified to allow the recovery of the following costs and/or credits: brokers fees; lime cost; sulfur credits and 100 percent of proceeds from the sale of SO2 allowances;
- TEP will continue to file with the Commission annually a request to reset its PPFAC rate.

TEP has filed a request, in Docket No. E-01933A-07-0402, to defer implementation of this year's PPFAC rate reset until the effective date of the decision in this case.

Q. Can you please explain the deferral request?

A. Pursuant to the current PPFAC approved by the Commission in Decision No. 70628, TEP is required to reset its PPFAC rate annually on April 1st of each year. The Signatories to the Agreement believe that in order to avoid a rate yo-yo effect, and in order to offset the current increase with a reduction in the PPFAC, it is in the public interest to defer the annual adjustment until the effective date of new rates in this docket.

Q. Please describe Section VII of the Agreement.

A. This section describes how TEP will implement its energy efficiency ("EE") program ("Plan"). The Signatories agreed that on an ongoing basis, consistent with Staff's Direct Testimony, TEP will treat energy efficiency similar to a typical generation resource. The Company will invest its own capital in cost-effective energy efficiency measures that have been approved the Commission.

Q. Is this a departure from how Energy Efficiency programs are being treated today?

A. Yes.

Q. Can you please explain?

A. Pursuant to the rules at Arizona Administrative Code R14-2-2401 *et seq.*, electric utilities such as TEP are required to achieve energy savings by implementing cost-effective energy efficiency programs. The utilities are required to file an implementation plan with the Commission for Staff's review and Commission approval. Based on the utility's plan and Staff's recommendation, the Commission sets a budget and a surcharge (DSMS). This surcharge collects money to pay for the EE program before the EE program costs are incurred.

However, consistent with this Settlement Agreement, the Company will invest its own capital, just as TEP does with other typical generation resource. After providing documentation that the energy efficiency programs have been effective, TEP will be given the opportunity to recover the cost of its energy efficiency investment, to include the rate of return established in this case, through TEP's existing DSM adjustor mechanism. To that effect, the Signatories agree to the following:

- TEP will amortize annual energy efficiency investments under the plan over five years.
- TEP will resume funding of programs previously approved by the Commission beginning March 1, 2013, and shall request recovery of such costs through the plan.
- Upon the effective date of the rates in this case, TEP will begin investing in cost-effective DSM/EE programs pursuant to the Plan for the remainder of year 2013 based upon the Commission's approval of the Plan, which includes the programs and the annual budget (approximately $12 million on a pro rata basis assuming a July 1, 2013 start date) recommended by Staff in Staff's proposed order for TEP's 2011-2012 Energy Efficiency Implementation Plan filed in Docket No. E-01933A-11-0055 on November 16, 2011.
- Upon the effective date of the rates in this case and approval of the Plan, TEP will file a request to close Docket No. E-01933A-11-0055.
- Any customer who can demonstrate an active DSM program and whose single site usage is 25 MW or greater may file a petition with the Commission for an exemption from the DSM adjustor and, if approved, will be removed from the Energy Efficiency Standard denominator. The Signatories are not required to support any such petition and some Signatories may plan to oppose any such petition.

- Upon adoption of the Plan, the DSM surcharge will be assessed on a per kWh basis for residential customers and on a percentage of bill basis for non-residential customers. The current DSM surcharge for residential customers will be reset from $0.001249 per kWh to $0.000443 per kWh upon the effective date of the new rates in this case.

Q. Please explain the rationale behind the departure from the existing methodology.

A. Consistent with the Company's presentation at the Integrated Resource Planning Workshop, where the Company maintained that energy efficiency is one of the cheapest resources, Staff believes it is in the public interest to treat energy efficiency similar to other typical generation resources.

Q. Please describe Section VIII of the Agreement.

A. This section of the Agreement addresses energy efficiency, lost fixed cost recovery ("LFCR"), fixed residential rate option and large customer exclusion. As stated above, the Signatories believe and support energy efficiency as a low cost energy resource. In addition, Commission rules related to energy efficiency and distributed generation require and cause TEP to sell fewer kWh, which in turn, does not provide the Company with the opportunity to recover a portion of the fixed cost of service embedded in its volumetric rates. To that point, the Signatories believe that by adopting the LFCR mechanism (which includes a residential fixed monthly rate option), TEP will have the opportunity to recover a portion of its fixed cost of service and receive possible relief from the financial impact of verified lost kWh sales attributed to Commission requirements regarding energy efficiency and distributed generation.

Q. Please explain how the LFCR will be administered.

A. As a part of the Agreement, a Plan of Administration that details how the LFCR will be administered is included as an exhibit. In addition, consistent with the Agreement, TEP and the Signatories agree to the following:

- The LFCR shall recover a portion of the distribution and transmission cost associated with residential, commercial and industrial customers.
- It shall not recover the lost fixed cost attributed to generation and to other potential factors such as weather or general economic conditions.
- The LFCR will have 1 percent year-over-year cap.
- Any amount in excess of the 1 percent cap will be deferred.
- Residential customers shall have a fixed LFCR rate option.
- TEP shall implement a customer outreach program by February 1, 2014, and shall seek stakeholder input in developing this program.
- The LFCR will recover lost fixed cost on a calendar year basis beginning January 1, 2013; however, the first LFCR surcharge will not go into effect until July 1, 2014.

Q. Please explain Section IX of the Agreement.

A. TEP will implement an Environmental Compliance Adjustor ("ECA") for government mandated environmental controls. The ECA provides for the recovery of and return on capital investments and associated costs related to environmental investments made by TEP and not already recovered in base rates approved in this case or recovered through another Commission-approved mechanism. These investments or projects are designed to comply with established environmental standards required by federal, state, tribal, or local laws and regulations. TEP must demonstrate that any environmental control is government mandated and is a reasonable and prudent option that was available to TEP at that time to meet such government mandate.

Q. Please explain Section X of the Agreement.

A. Currently, TEP is leasing Springerville Generating Station ("SGS") Unit 1; the lease is set to expire in January 2015. In order to ensure that the Commission obtain timely information on the status of SGS Unit 1 and to ensure that TEP has explored all options available to it when considering either to extend the lease, build a new generation resource, enter into a Purchase Power Agreement ("PPA") or other option, the Signatories agree that TEP will provide the following information to the Commission no later than July 31, 2014.

- Commitments made by TEP to purchase SGS Unit 1 or any agreement entered into by TEP to otherwise retain capacity rights to SGS Unit 1.
- Commitments made by TEP to purchase replacement generating resource, or any PPA entered into by TEP for replacement power.
- Commitments made by TEP to purchase the SGS Coal Handling Facilities or any agreement entered into by TEP to extend the Coal Handling Facilities lease.
- Estimated non-fuel revenue requirement associated with each commitment listed above, including the proposed rate treatment of any remaining balance of SGS leasehold improvements.

Q. Please describe Section XI.

A. This section deals with the Power Procurement Program. TEP agrees to adopt Staff's proposed modifications (except for the Risk Manager recommendation) to the Company's energy procurement program.

Q. Please explain Section XII of the Agreement.

A. Pursuant to Commission's Decision No. 59594, TEP set up a LIFE Fund of $4.5 million. The annual interest from the fund was used for the benefit of low-income customers. The Signatories agree that the LIFE fund should be eliminated and that TEP will make an annual contribution to the Arizona Community Action Association in the amount of $150,000 to fund the low income utility bill assistance program, commencing on September 1, 2013.

The Agreement will also limit Lifeline customers' increase to an amount that is generally reflective of the average monthly dollar increase of less than $3.00.

Q. Please explain Section XIII of the Agreement.

A. In its application, TEP was requesting rate recovery from the Commission for the cost related to the development of the transmission line from Tucson to Nogales; however, based on this Agreement, TEP agrees that it will seek recovery of those costs through the Federal Energy Regulatory Commission ("FERC").

Q. Please explain Section XIV of the Agreement.

A. In September 2011, there was a fire (thermal event) at the San Juan mine. Pursuant to this Agreement, TEP agrees to defer all the direct cost (except for the insurance deductible) related to the event until the insurance settlement has been completed. To that point, TEP agrees to the following:

- To maintain a separate accounting of all direct cost related to the event.
- That the estimated deferral cost is $9.7 million.
- That after a prudency review, TEP shall be eligible to put through all the prudent costs in excess of the insurance through the PPFAC.

Q. Please explain Section XVII of the Agreement.

A. The Signatories agree to eliminate the GreenWatts tariff. The Signatories believe that the recently approved Tucson Bright Solar project in the Renewable Energy Standard Implementation Plan is a substitute for the GreenWatts tariff.

Q. Please explain Section XVIII of the Agreement.

A. In order to maintain quality of service, TEP agrees to the following:

- Continue to evaluate reliability on the basis of distribution indices maintained at present levels.
- To initiate a study within 180 days of the effective date of the Decision to examine potential loss reductions and costs required to convert 4.16 kV circuits to 13.8 kV.

TEP also agrees to meet with Staff within 180 days of the effective date of the Decision to address the following:

- The possibility of increasing the pace of upgrading critical circuits in need of preventative maintenance.
- Establishment of a routine of periodic load flow analysis of its system and confirming the accuracy of utilized model.
- Equip feeder circuits with meters or other equipment so that power information can be relayed to Energy Management Service ("EMS") through Supervisory Control and Date Acquisition ("SCADA") to determine losses on a circuit by circuit basis.

Q. Please explain Section XIX of Agreement.

A. Pursuant to this section of the Agreement, TEP is requesting the elimination of certain reporting requirements as set forth in previous Commission Decisions or Commission rules. The Signatories agree with eliminating certain reporting requirements, with the exception of the following:

- The reporting requirement under Commission's Retail Electric Competition Rules (A.A.C. R14-2-1601).
- The cost containment report pursuant to Decision No. 59594.

Q. Can you please describe Section XX of the Agreement?

A. In an effort to address issues raised by some of the Signatories, the Company agrees to the following:

- In its next rate case, the Company will propose to treat the retail space to reflect revenue from rent equivalent to $20.83 per square foot.
- Within 60 days following the final decision in this docket, the Company will request that the Commission initiate a generic docket to address which accounting treatment of Net Operating Losses ("NOL") is appropriate.
- If TEP makes any filing with the Commission related to the early retirement of any production asset, TEP will propose that any then-existing excess depreciation reserve for Production Plant will be applied to the unrecovered book value of the retiring asset.
- TEP will propose in its next rate case that the remaining excess Production Plant depreciation, if any, after the application to the aforementioned early asset retirement will be amortized over 15years.
- TEP agrees to meet with RUCO and Staff once a year for the next 3 years to discuss TEP's capital expenditures, planning horizons, and related planning

(reconciled with TEP's IRP) for the upcoming year. TEP will provide the capital expenditure details and supporting information at least one week prior to the scheduled meeting.

- As a compliance item, TEP agrees that it will file in this docket by August 30, 2013, a proposed tariff for interruptible rates. Staff agrees that it will review the filing and docket a Staff Report and Proposed Order for the consideration of the Commission by December 31, 2013.
- In its next general rate case, TEP agrees to propose a rate for customers that take service at 138 kV or higher.

SECTION IV – RESPONSE TO COMMISSIONER GARY PIERCE'S LETTER

Q. On February 1, 2013, Commissioner Gary Pierce wrote a letter to the Docket setting forth several thoughts and questions regarding energy efficiency and the Energy Efficiency Resource Plan ("Plan") proposed in the Settlement Agreement. Have you read Commissioner Pierce's letter?

A. Yes.

Q. Do you have any comments regarding that letter?

A. Yes. Commissioner Pierce mentions perhaps permanently exempting TEP from the Commission's Energy Efficiency Rules ("EE Rules") if the Plan is implemented. From a Staff perspective, whether TEP is exempted from the EE Rules is a policy call for the Commission. However, even if TEP were no longer required to comply with the EE Rules, Staff still believes that the rate treatment for EE as outlined in the Plan and the Agreement is the correct treatment. In that instance, if TEP required additional generation resources as noted in its Integrated Resource Planning process, TEP could make the investment in EE resources and recover its investment as proposed by the Agreement.

Q. If the Commission is going to treat EE as any other typical generation resource, why would should the ratemaking treatment for such a resource be different than any other generation resource, i.e., through a DSM adjustor surcharge?

A. Unlike any other generation resource in which TEP invests, EE is the only generation resource that causes TEP to lose sales of kWh. Even when TEP invests in solar, since it owns that generation, it does not lose sales of kWh. However, with the installation of EE measures, TEP will lose sales revenue. It is for this reason that Staff believes that TEP should not be required to wait for the next rate case for the recovery of its EE investment, but instead recovery should occur through a DSM adjustor surcharge.

SECTION V - PUBLIC INTEREST

Q. Mr. Olea, is the Agreement in the public interest?

A. Yes, in Staff's opinion, the Agreement is fair, balanced, and in the public interest.

Q. Would you summarize the reasons that led Staff to conclude that the Agreement is fair, balanced, and in the public interest?

A. This Agreement results in a settlement package that addresses TEP's needs while balancing those needs with terms and conditions that provide customer benefits, such as:

- A limited first-year bill impact for customers (less than $3.00 per month[2] for a residential customer using the annual average of 767 kWh per month) despite the fact that TEP's current rates will have been in effect for almost 5 years at the time the new rates go into effect;
- A lower percentage rate impact on small commercial customers than the other customer classes;
- Continuing bill assistance for low income customers;

[2] This includes the PPFAC and the DSM surcharge but does not include the REST surcharge, taxes or assessments.

- A proposal that provides rate treatment for investments in energy efficiency in a manner similar to rate treatment for investments in other resources and that reduces the rate impact to the customer;
- An Environmental Compliance Adjustment mechanism that allows recovery, with a cap, of government-mandated environmental compliance costs in a manner that smooths the rate impact of such compliance;
- A narrowly-tailored LFCR mechanism that supports EE and DG at any level or pace set by this Commission; and
- A fixed cost LFCR rate option for residential customers preferring to a pay a specified charge for lost fixed costs rather than the variable LFCR.

Q. Please discuss how the Agreement is fair to the utility.

A. The revenue recommended will provide TEP with adequate funds to provide reliable and safe service, while at the same time ensuring the financial health of the Company. The LFCR mechanism will also improve TEP's revenue stability, which will have a positive impact on its financial profile and credit ratings.

Q. Mr. Olea, what was Staff's goal when it agreed to be a Signatory to the Agreement?

A. The primary goal of Staff in this matter, as in all rate proceedings before the Commission, is to protect the public interest by recommending rates that are just, fair and reasonable for both the ratepayers and the Company. Staff believes it has accomplished this by reviewing the facts presented and making the appropriate recommendations to the Commission for its consideration, which will balance the interests of the Company and the ratepayers, by promoting the Commission's desire to ensure that the Company has the tools and financial health to provide safe, adequate and reliable service, while complying with Commission requirements at just and reasonable rates.

SECTION VI – POLICY CONSIDERATIONS

Q. Mr. Olea, what was the major policy considerations the Signatories had to deal with in this Docket?

A. I believe there were two major policy considerations that Staff and other Signatories had to address in order to balance the interests of all Signatories. The Commission, in Docket Nos. E-00000J-08-0314 and G-00000C-08-0314, issued its Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Policy Statement"). The Policy Statement did not adopt a requirement or mandate a specific revenue decoupling mechanism, but noted that utilities may file a proposal for decoupling or an alternative mechanism for addressing disincentives, in their next general rate case. The other policy consideration has to do with the implementation of EE programs. In this Agreement the Signatories agree that EE should be treated as any other typical energy source. In addition, the Signatories also agree that rather than collecting the surcharge in advance from its ratepayers, the Company first will invest its own capital, just like with other typical generation resources, thereafter the Company can then seek recovery on and of its investment, after a prudency determination.

Q. Is there anything else you would like to add regarding the Agreement?

A. I would like to reiterate that the settlement discussions were transparent, candid, professional and open to all parties in this docket. All Parties were allowed to openly express their views and opinions on all issues. I believe the Settlement Agreement is in the public interest.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

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

TESTIMONY

IN SUPPORT OF

THE SETTLEMENT AGREEMENT

HOWARD SOLGANICK

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

FEBRUARY 15, 2013

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ATTACHMENT

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

My testimony details the background concepts and various rate design elements within the Settlement Agreement.

My testimony reviews the details and implementation of the Lost Fixed Cost Recovery ("LFCR") mechanism proposed in the Settlement Agreement and defined by the Plan of Administration.

I provide details of the LFCR mechanism; the sources of required data; how the initial year is recognized; that the sales reductions are documented by an existing process; how the annual calculations are made; the customer protections included; and the opportunity for review and compliance reporting.

I also compare the LFCR mechanism to revenue decoupling, highlighting that weather, business and other risks are not transferred to customers.

Staff recommends that the rate design and Lost Fixed Cost Recovery mechanism, as proposed in the Settlement Agreement, be adopted.

SECTION 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 prepared and 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, regulatory issues and restoration after major outages.

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 major storms that affected New Jersey in 2011.

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 and rate design on January 11, 2013.

I have also testified and/or presented testimony (summarized in Attachment 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

SECTION II – DIRECT TESTIMONY

Q. For whom are you appearing in this proceeding?

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

Q. What is the purpose of your testimony?

A. My testimony supports the Settlement Agreement for Tucson Electric Power Company ("TEP" or "Company") filed by Staff on February 4, 2013, specifically the rate design and the Lost Fixed Cost Recovery ("LFCR") mechanism.

I describe the background and elements of the revenue allocation and rate design proposed to be implemented as a result of the Settlement Agreement.

My testimony also describes the operation of the LFCR mechanism adopted by the parties to the Settlement Agreement. I compare the LFCR mechanism to the generic concept of revenue decoupling; compare the risks transferred to customers and other aspects of decoupling a utility's revenues.

Rate Design

Q. How was the revenue allocation between the major rate classes determined?

A. In its testimony, the Company proposed the use of an Average and Peak ("A&P") methodology to allocate production plant (generation). Arizonans for Electric Choice & Competition ("AECC") proposed the use of an Average and Excess ("A&E") methodology. Kroger Company proposed a 100% demand 4 coincident peak methodology. In my rate design testimony, I highlighted that the Company was planning investments to meet future peak loads and to retain cost effective lower cost energy generation. This situation supports a cost allocation methodology that reflects methodologies such as A&E or A&P. During the settlement process the parties advocated for their methodologies and the revenue allocation in Attachment B of the Settlement Agreement was agreed upon. This revenue allocation also reflects the cost of service situation of the Small General Service class that had the highest return of any class.

Q. What are the major rate design concerns addressed in the Settlement Agreement?

A. At present, customers have a myriad of rates to choose from with the resulting costs to administer. The Company proposed the consolidation of a number of rates to reduce customer confusion and costs. The large number of currently available rates and the Company's proposal to consolidate those rates is well detailed in Exhibit CAJ-2 to Company witness Craig Jones' Direct Testimony. The Company also proposed to increase the customer charges, which would stabilize its revenue and reflect its cost structure.[1] For classes that have demand charges, the Company also proposed to increase demand charges for the same reason. Frozen rates were proposed to be eliminated and consolidated with other rate schedules.[2]

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[1] Jones Direct 29:1
[2] Jones Direct 24:21

The Settlement Agreement includes the consolidation of rates to reduce customer confusion and decrease administration costs. It also unfreezes rates, raises customer charges, raises demand charges and increases the demand ratchet.

Q. Why are frozen rates created and what are the initial effects?

A. Rates are often frozen to shield a class or subclass from the effects of a rate increase. If "freezing" affects only a subclass of a rate schedule then that results in creation of an additional rate schedule with its attendant costs of administration. New customers starting service after a rate is frozen may not be eligible for the frozen rate creating a situation where two similar customers pay different rates for the same service.

Q. What are the longer term effects of frozen rates?

A. At the utility's next rate case, the subclass has an incentive to maintain its favored position even though costs may have increased for that subclass. Additionally, the process of merging the frozen rate back into an existing rate schedule often entails an above average increase for the subclass, which may be objectionable thus perpetuating the subclass. Members of the original subclass may move and no longer directly need the frozen rate but often the subclass requests that the frozen rate follow the customer not the location of the usage. Each of these situations causes the frozen rate to diverge from the original good intentions. In some cases, an exemption from an adjustor such as fuel and purchase power works against the subclass when costs decrease and the adjustor goes negative, but the subclass receives no benefit from the credit due to its previous exemption.

Q. What rate design changes for non-time of use ("TOU") residential customers are proposed in the Settlement Agreement?

A. The number of residential rates has decreased. The non-TOU Rate R-01 now includes a block at 501-1000 kWh, which better reflects the average customer's usage. The customer charge has been increased to $10.00 per month, which better matches rates to costs and serves to lower the LFCR adjustment. There are now five summer months rather than six. The existing Rate R-02 for water heating is now rolled into the Rate R-01. New Lifeline customers are eligible for a flat $9.00 per month discount up from $8.00.

The Rate R-201AN, for space and water heating customers, now includes a block at 501-1000 kWh. The customer charge has been increased to $10.00 per month, which better matches rates to costs and serves to lower the LFCR adjustment. There are now five summer months rather than six. New Lifeline customers are eligible for a flat $9.00 per month discount up from $8.00.

Q. What rate design changes for TOU residential customers are proposed in the Settlement Agreement?

A. To encourage adoption of TOU rates, a six-hour summer On-Peak period has been adopted and the shoulder period has been eliminated. The shorter summer On-Peak period offers customers more opportunities to shift load to off-peak periods.

The residential TOU Rate R-80 now includes a reduced Off-Peak energy charge for electric vehicle owners to encourage charging electric vehicles during off-peak hours instead of on-peak. To reduce costs, this rate does not require a separate meter for the electric vehicle.

Q. What rate design changes for Lifeline customers are proposed in the Settlement Agreement?

A. The Company had proposed to consolidate Lifeline customers within the standard residential rates. Staff supported this consolidation and sought to maintain the level of support for Lifeline customers. The complete consolidation could not be accomplished without excessive impacts on some Lifeline customers that did not reflect the average increase of a standard Rate R-01 customer. Therefore, separate Lifeline rates (and characteristics) continue to be available in order to preserve the benefits to existing Lifeline customers. For existing TOU Lifeline customers their TOU characteristics (periods and seasons) have not been changed. In a move toward consolidation, the Purchase Power and Fuel Adjustment Clause ("PPFAC") rate and the Demand Side Management ("DSM") surcharge will now apply to Lifeline customers.

New Lifeline customers can take service under Rates R-01 and R-201AN or TOU Rates R-80 and R-201BN and receive a flat $9.00 discount. Existing Lifeline customers that move are now considered new customers and transition to these "standard" rates and the flat $9.00 discount.

Q. How have residential customers that want to retain an analog meter been accommodated?

A. For residential customers that do not wish to have the benefit of automated meter reading ("AMR"), the residential rates offer the ability to retain an analog, non-AMR meter as long as the obsolete technology is economically available, but this rate also recognizes the additional costs that the customer's decision imposes on the Company. The additional charges for non-AMR metering encourage the Company and the customer to jointly reduce costs through self-meter reading.

Q. What rate design changes for small general service customers are proposed in the Settlement Agreement?

A. The customer charge has been increased and a number of rates have been consolidated.

Q. What rate design changes for municipal customers are proposed in the Settlement Agreement?

A. To reduce the impact on Rate PS-40 serving municipal customers, which will be served on Rate GS-10, a 'rate blocker" mechanism has been implemented to reduce the rates by 16.5% (except for the Customer Charge). This rate blocker is designed to ease the transition to Rate GS-10.

Q. What rate design changes for water pumping customers are proposed in the Settlement Agreement?

A. The customers of the present Rate GS-31 and Rate PS-43 will be consolidated within Rate GS-43 that also includes an interruptible option. Rate GS-43 customers are excluded from the LFCR mechanism.

Q. What rate design changes for large general service customers are proposed in the Settlement Agreement?

A. Customers on demand rates will also be consolidated, demand rates will be increased and the demand ratchet has been increased to 75%. These changes serve to reflect fixed costs, standardize the demand ratchet and for Rate LLP-14 and Rate LLP-90 the increase in demand charges allows for these customers to be excluded from the LFCR mechanism.

Q. What rate design changes for TOU non-residential customers are proposed in the Settlement Agreement?

A. To encourage adoption of TOU rates a six-hour summer On-Peak period has been adopted and the shoulder period has been eliminated. The shorter summer On-Peak period offers customers more opportunities to shift load.

Q. What tariff changes are proposed in the Settlement Agreement?

A. The treatment of non-residential customer deposits has been changed to provide a refund after two years similar to both UNS Gas, Inc. and Arizona Public Service Company ("APS").

Q. What protections are offered to customers that may be adversely affected by the new rate design?

A. Although the parties have explored the rate impacts of the new rate design and consolidation, the Company does not have an extensive customer research program in place. There is a possibility of unforeseen impacts to customers. The rate design portion of the Settlement Agreement is held open until July 1, 2014 to allow for the possible adjustment of specific tariffs to correct for unanticipated customer rate impacts that are determined to be inconsistent with the public interest, while not reducing the Company's non-fuel revenue requirement.

Q. Do you recommend the adoption of the rate design portion of the Settlement Agreement?

A. Yes. I recommend the adoption of the revenue allocation and rate design proposed within the Settlement Agreement as it not only has been accepted by the Signatories but also implements many of the rate design concepts proposed by Staff, other interveners and the

Company. These rate design concepts will reduce customer confusion, ease tariff administration, encourage the adoption of TOU rates and offer other benefits to customers.

Lost Fixed Cost Recovery

Q. Have you reviewed specific decoupled rate design proposals?

A. I have reviewed proposals for decoupled electric and gas rate designs in Delaware for the Staff of the Delaware Public Service Commission where I also assisted in the pre-implementation education process. I have also reviewed decoupling proposals by gas utilities and offered testimony in Maryland for the People's Counsel and in Michigan for the Attorney General. In addition, I assisted the Staff of the District of Columbia Public Service Commission in the evaluation and implementation of a decoupled rate design for delivery of electricity. I provided testimony and assisted in the development of the settlement that included rate design changes and the LFCR mechanism for APS on behalf of Staff.

Q. What is the purpose of the LFCR mechanism?

A. The LFCR mechanism is designed to provide recovery of the Test Year fixed costs that have been documented to be lost as a result of the Commission approved energy efficiency ("EE") and distributed generation ("DG") programs. These fixed costs are related to transmission and distribution revenue requirements that are collected in volumetric rates rather than in demand charges or a fixed charge such as the Customer Charge. The LFCR is designed to remove the disincentive against EE and DG that arises when the Company's sales are reduced by those programs.

Q. Please describe how the LFCR mechanism works.

A. The LFCR mechanism would begin on January 1, 2013 on a calendar year basis with the first LFCR surcharge expected on July 1, 2014.

After the Commission's decision in this case, the Company's compliance filing will define the values for the LFCR mechanism. The Lost Fixed Cost Rate is the allowed Distribution and Transmission Revenue divided by the test year billing determinants. Generation fixed costs are not included in the LFCR.

The annual LFCR process is initiated by the Company's Measurement, Evaluation and Research ("MER") of its EE program results. The Company's outside MER consultant studies each EE program and determines the level of energy sales reductions for each program during the preceding year. The Company uses the MER report to determine the sales reduction for the applicable rate schedules. The Company is metering the DG sales reductions. The sales reduction for the applicable DG is added to EE sales reduction and is called the Recoverable kWh Savings.

The Company will file its annual LFCR Adjustment for the previous calendar year by May 15th. This adjustment is the product of the Recoverable kWh Savings times the applicable Lost Fixed Cost Rate. That product is divided by the Applicable Company Revenues to determine the LFCR Adjustment. The Staff will perform its review of the compliance reports and other data including the MER. The LFCR adjustment would be applied to customer bills beginning July 1st, after Commission approval.

Q. Is there an option for those residential customers do not wish to be subject to the LFCR mechanism?

A. Residential customers that do not wish to be subject to the LFCR mechanism can select an alternate Customer Charge ("Lost Fixed Cost Recovery Fixed Charge option") within their existing rate schedule. After a trial period, the customer will have to remain on the alternate Customer Charge for at least 12 months. During the calculation of the LFCR Adjustment, the associated sales and revenues of these customers are excluded.

Q. Are there customer (rate) classes that will not be subject to the LFCR mechanism?

A. Yes. Lighting, water pumping and large light and power customers served under rate schedules PS-41 and PS-50, GS-43, and LLP-14 and LLP-90, respectively are excluded from the LFCR mechanism because these rate schedules have fixed charges and/or are not expected to be impacted by EE and DG programs. The demand charge in some of these rate schedules was increased to allow them to be excluded from the LFCR mechanism.

Q. Why are the other rate schedules subject to the LFCR mechanism?

A. The included rate schedules are expected to be impacted by EE and DG programs and have some or all of the fixed transmission and distribution costs collected by a volumetric rate.

Q. Why does the LFCR mechanism not include generation costs?

A. The Company's Integrated Resource Plan demonstrated that total sales are still expected to rise in the near future. The Company also has off-system and/or non-Commission jurisdictional opportunities to sell any excess energy, therefore, there is no need to include generation costs in the LFCR mechanism.

Q. Why does the LFCR mechanism not include the Customer Charge?

A. If a customer reduces its energy consumption in response to an EE or DG program, the customer is still responsible for paying the applicable Customer Charge. Therefore, there is no need to include the Customer Charge in the LFCR mechanism.

Q. Why does the LFCR mechanism recover only 50% of the distribution demand charge revenue?

A. If a customer reduces its energy consumption in response to an EE or DG program, it is unlikely that there will be a proportional reduction in the demand level. To recognize that there may be some demand reduction a 50% Demand Stability Factor is applied, which reduces the magnitude of the LFCR adjustment.

Q. Is there a cap on the LFCR mechanism?

A. Annual adjustments are limited to 1% and are estimated to be below that level for the next four years based on the expected level of EE and DG programs.[3] The EE and DG programs are subject to the Commission's annual review and approval process.

Q. How are the claimed EE sales reductions measured and verified?

A. A MER review is integral to a well-designed EE program. The Company's annual MER report will be used to estimate or measure the results of its energy efficiency programs. Good practice requires that the Company examine the effectiveness of each EE program. Over time new energy savings technologies become available, existing technologies become commonplace and some programs are found to have been poorly constructed or ineffective.

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[3] Solganick Direct Exhibit HS-3

The MER process employs an outside party to study the performance of each EE program using various techniques and statistical methods. MER is a common and established practice.

Q. Does the LFCR mechanism increase the Company's revenue?

A. No. LFCR is limited to only the documented reduction of sales that occur after December 31, 2012. The mechanism provides the Company with revenues lost due to EE and DG programs. If no sales are lost there is no LFCR Adjustment.

Q. Does the LFCR mechanism provide additional revenue if the Company's sales decline due to weather?

A. No. Should weather conditions be normal, any sales reductions as a result are not included in the LFCR mechanism. Weather risk remains with the Company and its shareholders as it is now. The LFCR mechanism is focused on the measured sales reduction due to the EE and DG programs. These programs are those determined by the Commission to be cost effective and appropriate.

Q. Does the LFCR mechanism provide additional revenue if the Company's sales decline due to economic conditions?

A. No. Should economic conditions worsen, any resulting sales reductions are not recovered by the LFCR mechanism. Business risk remains with the Company and its shareholders as it is now.

Q. Does the LFCR remove the disincentive to the Company to engage in EE and DG programs and activities?

A. Yes. The LFCR mechanism provides a means to recover lost fixed costs that result from documented sales reductions due to EE and DG programs. From a revenue perspective, the Company is neutral.

Q. If the Company failed to achieve documented results from its EE and DG programs what is the effect of the LFCR mechanism?

A. If the Company's MER is unable to document sales reductions from its EE and DG programs, then the LFCR mechanism would produce a zero result and customers would see no impact for that period.

Q. How is revenue decoupling different from the LFCR mechanism?

A. As applied in some jurisdictions, generic revenue decoupling looks at a gross measure of sales reduction per customer and adjusts revenue levels to compensate for any changes. The sales reduction could be the result of weather, economic conditions, outages, price elasticity or the result of EE and DG programs.

Q. What risks are transferred from the utility to the customer if revenue decoupling is implemented?

A. The implementation of generic revenue decoupling usually transfers outage, weather and business risks to customers.

Q. Is transferring these risks to customers necessary to encourage a utility to pursue EE and/or DG programs?

A. No. While generic revenue decoupling will remove the perceived disincentives of EE and DG programs, the shift of other risks to customers is not necessary.

Q. Is the administration of revenue decoupling less costly than an LFCR mechanism?

A. No. There is no additional cost for the MER. The LFCR calculations use compliance filing values and annual sales data and are made once per year by the Company and reviewed by Staff.

Revenue decoupling requires similar sales data for its calculation. In some jurisdictions, the concern over the impact of weather has led to revenue decoupling implemented on a monthly basis, requiring additional calculations and reviews. If weather is excluded, then a weather normalization process must be applied to the sales data on a monthly basis, requiring additional algorithms, calculations and reviews. If outages are a concern, then a process has to be developed to reflect lost sales due to each applicable outage, which must be tracked and analyzed.

Q. What is your recommendation?

A. I recommend that the LFCR as proposed by the Settlement Agreement be adopted. The LFCR mechanism is the result of the input of a number of parties to this Settlement Agreement. It is designed to remove the Company's disincentive to pursue EE and DG programs due to sales reductions.

The lost fixed cost rate is determined as a result of the rate case and will be part of the compliance filing.

The existing MER evaluation process documents the sales reduction.

There is an option for residential customers that wish to exclude themselves from the LFCR mechanism. To further stabilize revenues, the demand rates of some of the excluded rate schedules have been increased.

The LFCR mechanism does not shift weather or business risks to customers; they remain with the Company and its shareholders.

There is a 1% annual cap on any increases resulting from the LFCR mechanism.

Reporting requirements have been defined. The calculations are defined and performed annually. There is a process to provide Staff with adequate time for the annual review.

The LFCR mechanism specified in the Settlement Agreement is very similar to the LFCR mechanism adopted for APS.

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

A. Yes.

Testimony of Howard Solganick
Docket No. Docket No. E-01933A-12-0291

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 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.

Testimony of Howard Solganick
Docket No. Docket No. E-01933A-12-0291

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.

Testimony of Howard Solganick
Docket No. Docket No. E-01933A-12-0291

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.

Testimony of Howard Solganick
Docket No. Docket No. E-01933A-12-0291

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-2010-2166212 (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