Rebuttal Testimony of

David J. Lewis

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
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 THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

Rebuttal Testimony of

David J. Lewis

on Behalf of

Tucson Electric Power Company

July 25, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David J. Lewis and my business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct Testimony in this proceeding?

A. No.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP" or "Company").

Q. What is your position with TEP?

A. I am the Manager of Revenue Requirements for UNS Energy Corporation ("UNS Energy"), an indirect, wholly owned subsidiary of Fortis Inc. ("Fortis"). I am responsible for monitoring and determining revenue requirements for all the regulated subsidiaries of UNS Energy, including TEP.

Q. Please describe your education and experience.

A. I hold a Bachelor of Science in Business Administration, a Master's of Business Administration and a Master's of Science in Accountancy. I have over 13 years' experience within the utility industry.

Prior to working for UNS Energy, I was employed by Green Valley Water Company as the principal accountant reporting directly to the Controller.

Before then, I was the business support analysis for Raytheon Missile Systems NAPI facility in Farmington, New Mexico.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. I address certain adjustments that Staff witnesses Donna Mullinax, Roxie McCullar and Michael McGarry recommend in their Direct Testimonies. I also address adjustments that Residential Utility Consumer Office ("RUCO") witnesses Jeffrey Michlik and Frank Radigan proposes in their Direct Testimonies. Any inadvertent omission of discussion of any adjustment should not be considered an acceptance of the position or recommendation.

Q. What else do you address in your Testimony?

A. I am providing an exhibit (**Exhibit DJL-R-1**) that summarizes adjustments that the Company is making in its Rebuttal Testimony.

II. COMPUTATION CORRECTIONS TO STAFF'S AND RUCO'S DIRECT FILINGS.

Q. Are there computation errors that you have identified within Staff's or RUCO's Adjustments?

A. Yes. I have provided an attachment, **Exhibit DJL-R-2 and Exhibit DJL-R-3,** which summarizes and explains the errors that I have identified and sets forth the corrected adjustments.

Q. What computation errors did you identify?

A. As explained in **Exhibit DJL-R-2 and Exhibit DJL-R-3**, the following errors were identified.

1. Correction of Staff's adjustment E-5 Cash Working Capital. Staff inadvertently used the ACC Jurisdictional factor twice in its calculation.

2. Staff did not adjust Accumulated Deferred Income Taxes to reflect proposed changes to Rate Base.

3. Correction of Staff's adjustment E-6 Depreciation Expense. Staff's methodology to adjust Accumulated Depreciation is incorrect. The Average Remaining Life depreciation technique used in the current depreciation study. It is a self-correcting approach in that its continued application constantly trues up the proposed depreciation rates over the average remaining life of the property to assure full recovery of the total asset cost. Therefore, Staff does not need to adjust accumulated reserve as proposed. Reducing the reserve balance overstates the asset value on which the Company is earning a return.

4. Correction to RUCO's adjustment JMM-22 Overhaul and Outage. During the discovery process, the Company identified a formula error that understated the amount of test year outage expense. RUCO's adjustment used the revised outage expense amounts; however, RUCO's intent was to adjust test year outage expense to a normalized amount of $8,127,571. The adjustment however reduced the filed outage amount proposed by the Company to $7,165,217. RUCO should have started with the Company's filed position, not the revised position since the revised amount was not reflected in the original revenue requirement they are adjusting from.

5. Correction to RUCO's adjustment JMM-24. The Accrual rates used in RUCO's post-test year adjustment do not reflect what TEP is currently requesting. The Company's post-test year pro-forma adjustment calculated ACC jurisdictional depreciation of $4,137,853. RUCO's pro-forma adjustment removes $7,870,808, which is roughly 60% more than the Company's filed position. This is because most of the accrual rates used by RUCO were twice that of what

the Company proposed. RUCO's pro-forma methodology removed twelve months of depreciation expense from test year expense for both post-test year plant and post-test year plant renewables. This is incorrect as explained in the Company's response to RUCO's data request RUCO 11.2 (attached as **Exhibit DJL-R-4**).

6. RUCO did not adjust Accumulated Deferred Income Taxes to reflect proposed changes to Rate Base.

7. Correction to RUCO's JMM-22 Overhaul and Outage. RUCO did not adjust the frequency percent to reflect a levelized average over the 2005 through 2015 period. RUCO intended to calculate a levelized average spread over 11 years instead of 17 years as reflected in their actual adjustment. This error occurred because RUCO did not correct the frequency formula, instead they used what was being calculated in the original pro-forma. Had RUCO corrected the formula, RUCO's revised Overhaul and Outage expense would have been approximately $13.1 million, not the $8.1 million presented in JMM-22.

III. REBUTTAL TO RATE BASE ADJUSTMENTS.

A. Post-Test Year Plant.

Q. Did Staff or RUCO make any adjustments to the Post-Test Year rate base amounts requested by the Company?

A. Yes, Staff witness Donna Mullinax removed 16 post-test year plant projects, 14 regular projects[1] and three renewable energy projects[2]. This adjustment reduces ACC

[1] Staff Adjustment E-1, Mullinax Direct Revenue Requirement Testimony, Table 2, page 9.
[2] Staff Adjustment E-2, Mullinax Direct Revenue Requirement Testimony, Table 4, page 13.

jurisdictional original cost rate base ("OCRB") by approximately $30.6 million.[3] RUCO witness Frank Radigan recommends the removal of all post-test year amounts proposed by the company. RUCO's adjustment reduces OCRB by approximately $80 million.

Q. Do you agree with Staff's recommendation to remove these 16 Post Test Year plant projects?

A. No, I do not. Ms. Mullinax recommends excluding post-test-year plant that was not in service within six months after the end of the test year. Her recommendation applies to regular Post Test Year Plant (Staff Adjustment E-1) and renewable Post Test Year Plant (Staff Adjustment E-2). Her reasoning is that the integrity of using a test year becomes increasingly blurred as more and more adjustments are made beyond the end of the test year period[4]. <u>However, the Company is only requesting to include the costs incurred prior to the end of the test year, and invested in plant items that will be in service and benefiting customers by the time new rates are effective. We are not asking for inclusion of any costs incurred post-test year.</u> These facilities will primarily be used to maintain service levels and system reliability and will serve existing test year customers.

Q. How much of the ACC Jurisdictional $30.6 million in Post Test Year plant removed from rate base by Staff is currently In Service?

A. The $30.6 million in Post Test Year plant is made up of $14.7 million in non-renewable projects and $15.9 million in renewable projects. For non-renewable projects, of the $14.7 million identified by Staff, approximately $13.3 million has been placed into service as of June 30, 2016. The Company expects the remaining $1.4 million to be in service by the time new rates become effective. For the renewable projects, of the $15.9 million identified by Staff, $7.2 million will be in service by August 31, 2016, and the

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[3] Reduction to rate base of $15.9 million (Mullinax Direct Revenue Requirement Testimony, page 13, line 12) and $14.7 million for non-renewable plant (Mullinax Direct Revenue Requirement, page 9, line 8.

[4] Mullinax Direct Revenue Requirement Testimony, page 10, line 3 through 6.

remaining $8.7 million will be in service prior to new rates becoming effective. A list showing the current status of each of these 16 projects is attached as **Exhibit DJL-R-5**.

Q. Has the Commission allowed the use of Post-Test-Year Plant before?

A. Yes. The Commission approved including Post-Test-Year Plant for UNS Electric in the 2013 UNS Electric Rate Order. The Commission has also allowed Post-Test-Year Plant in numerous other cases, including: EPCOR Water Arizona, Inc., in Decision No. 75268 (December 31, 2015); Chaparral City Water Company, Decision No. 74568 (June 20, 2014); TEP in Decision No. 73912 (June 27, 2013); Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012), Rio Rico Utilities, Inc., in Decision No. 67279 (October 5, 2004); Arizona Water Co., in Decision No. 66849 (March 19, 2004); and Bella Vista Water Co., Inc., in Decision No. 65350 (November 1, 2002). Staff's response to TEP Data Request 2.1 shows that the Commission has not limited Post-Test Year Plant to 6 months and has approved longer periods in a number of cases. A copy of this response is attached as **Exhibit DJL-R-6**.

Q. Do you agree with RUCO's recommendation to remove all of Post-Test Year plant proposed by the Company?

A. No. As noted above, the Commission on several occasions has allowed companies to include Post-Test Year plant in rate base. Mr. Radigan believes the Company's request for post-test year plant recovery in rates requires a detailed presentation that the large and continuous build out of infrastructure reflects appropriate, efficient, effective, and timely decision-making.[5] As stated in Company witness Mr. Hutchens rebuttal testimony, as part of the Company's last rate case, TEP agreed to meet annually with Staff to review the Company's actual capital spending and future plans for the upcoming year. The point of these meeting is to create a free exchange of information of what the company needs in

[5] Radigan Direct Revenue Requirement Testimony, page 29, lines 9 through 13

order to maintain and improve system reliability and effective service. Mr. Radigan's argument is without merit and should not be considered.

B. <u>Sundt Coal Handling Facilities.</u>

Q. Did Staff or RUCO make and adjustment for Sundt Coal Handling Facilities?

A. Yes, Staff accepted the Company's ACC jurisdictional allocation correction to original filing. This adjustment increased jurisdictional rate base by $20,000.

C. <u>Sundt and San Juan Unit 2 Materials and Supplies.</u>

Q. Please explain the update to the Sundt Coal Handling Facility Materials and Supplies pro-forma adjustment.

A. Company witness Frank Marino is supporting this adjustment. The Revised adjustment increase rate base by $731,117 and reduces operating income by $243,706.

IV. <u>REBUTTAL TO OPERATING INCOME ADJUSTMENTS.</u>

A. <u>TEP Proposed Depreciation Rates</u>.

Q. Did Staff or RUCO adjust the proposed accrual rates as outlined in the 2015 Depreciation Study?

A. Yes. Staff witness Ms. McCullar recommends: a -5 percent future net salvage percent for Distribution plant; a final retirement year of 2032 for Sundt Steam Units 1 and 2; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2; and the estimated dismantlement costs be set at current dollars instead of an estimated future dismantlement costs. I will address the recommended -5 percent future net salvage percent and the dismantlement cost set at current dollars. Company witness Michael Sheehan will address the final year retirement dates proposed by Staff.

Q. Do you agree with Staff's proposal that dismantlement cost be set at current dollars?

A. No. Ms. McCullar believes it is inappropriate to charge ratepayers now for the estimated dismantlement cost in future dollars at the time of retirement, and instead proposes to estimate dismantlement costs in current dollars. This proposal is inappropriate and does not incorporate all the factors that should be considered in ratemaking, particularly the equitable treatment of different generation of customers. After accruing for terminal net salvage in current dollars, TEP will have to capitalize net cost of dismantlement in future years (when the facility is no longer providing service) to be recovered by future customers and not by the customers presently receiving service from these assets. Ms. McCullar proposal is designed to reduce rates for today's customers but to do so at the expense of tomorrow's customers. In addition, Ms. McCullar's approach ignores the reality of inflation; these future retirement costs will not be paid in current dollars, but rather in inflated future dollars at the time of retirement.

Q. Is it appropriate to ask current customers to pay for future costs of plant removal?

A. Yes, the future cost to remove plant is part of the service value that it renders to current customers, and a portion of those costs should be recovered from current customers. As future costs are recovered from current customers, they are deducted from rate base. Thus, current customers receive a benefit as they pay their fair, ratable portion of those costs.

Q. Do you agree with Staff's position to set net salvage for Distribution Plant at -5 percent?

A. Yes. The -5 percent future net salvage represents the 25 year historic average; therefore, using -5 percent for net salvage is appropriate.

Q. What do you recommend for Dismantlement costs and net salvage for Distribution Plant?

A. While TEP strongly believes that the requested Accrual rates provided in the 2015 Depreciation study should be approved, the Company will accept Mrs. McCullar recommendation of -5 percent future net salvage for distribution plant and dismantlement costs be set a current dollars in this proceeding. However, in the Company's opinion it is just pushing today's "cost to serve" to future customers.

B. <u>Overhaul and Outage Adjustment</u>.

Q. Did Staff or RUCO make an adjustment for Overhaul and Outage expense?

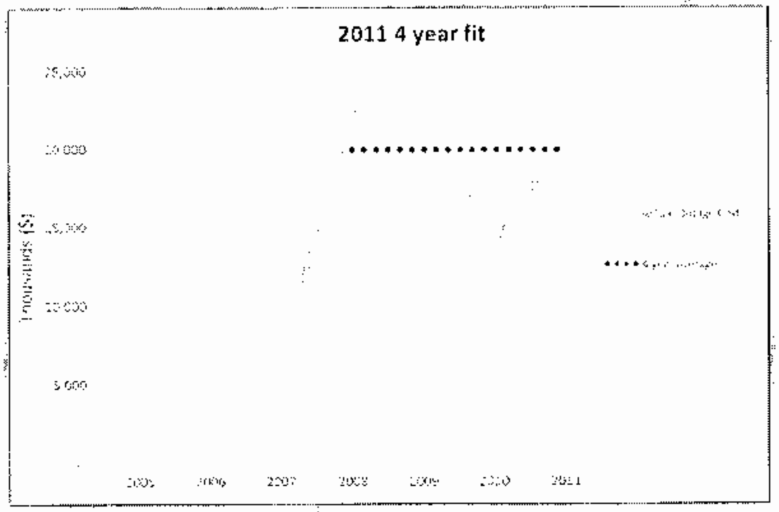
A. Yes, Staff witness McGarry, used a four-year period (2012 through 2015) to reflect the typical methodology to normalized expense between base rate cases. RUCO witness Michlik uses an historical average from 2005 to 2015 to reflect overhaul and outage expenses.

Q. Do you agree with either Staff or RUCO's adjustment?

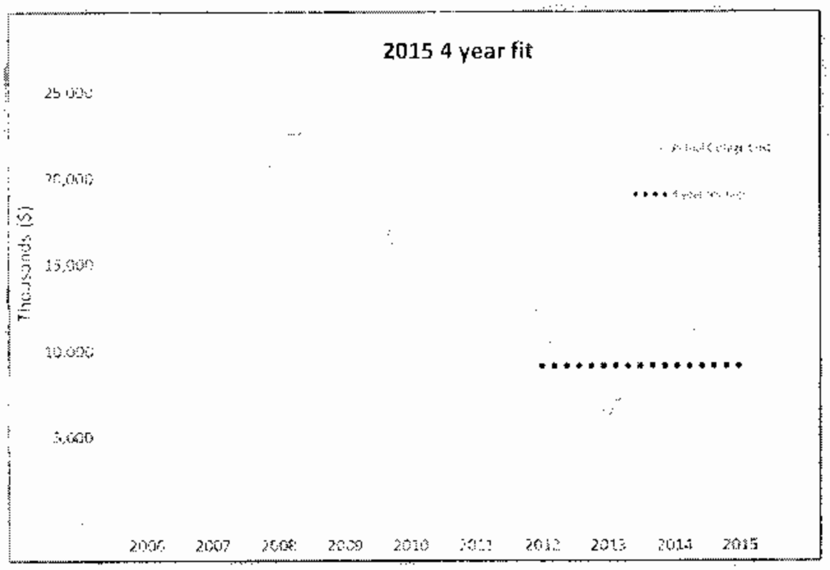
A. No. First I will address my concerns with Mr. Michlik's adjustment. Ignoring the mathematical error explained earlier in my testimony, the Company strongly opposes Mr. Michlik's exclusion of outage expense related to Gila River Unit 3. As explained in greater detail by TEP witness Mr. Sheehan these outage costs are not represented in the calculation proposed by Mr. Michlik. In the most recent UNS Electric case, Mr. Michlik did not oppose recovery of the 25% ownership share of outage expense to be recovered in UNS Electric's base rates therefore, the Company does not understand his rationale to exclude TEP's share of these same outage costs from TEP's base rates.

By appropriately including Gila River Unit 3 and correcting for the calculation error; RUCO's levelized overhaul and outage expense would be $14.6 million. This is roughly the same as the company's revised position.

Staff witness McGarry methodology to "normalize expense" over a four year period significantly under recovers the actual levelized outage costs. As part of the 2013 TEP Settlement Agreement, the Company accepted Staff's ACC jurisdictional outage expense of $11.6 million to be recovered through base rates. This adjustment was based on actual historical costs for the period 2004 to 2011. Mr. McGarry's proposal to use just a four-year period will reduce outage costs to roughly $9.1 million. Had the Company used McGarry's four year average methodology in the last rate case, the outage expense would have been roughly $19 million. It seems that Staff's methodologies are changing significantly between rate cases with no recognition of the reality of the timing of outages. Generation overhauls are quite costly and do not occur at regular annual intervals. In general, minor overhauls are performed every 1 to 3 years and major overhauls are performed every 5 to 8 years. Thus, a 4 year normalization will completely miss the cost of major overhauls in some test years, while the normalized cost would shoot up if the major overhaul falls within the 4 year window. To use such a short normalization period will lead to extreme volatility in the normalized levels as depicted on the following tables:



*The chart above depicts higher averages cost in years where there are major outages.



*The chart above depicts lower average cost in years where there are no major outages.

As can be seen by these two graphs using a simple four year average creates huge swings in levelized outage expense. These swings are attributable to major outages that do not occur consistently in such short duration periods. Had McGarry used a 10 year historical average, the result would have been similar to the requested amount proposed by the Company in its original filing.

C. Rate Case Expense.

Q. Did Staff or RUCO dispute the Company's pro forma rate case expense?

A. Yes, Staff recommends rate case expense of $900,000 normalized over four years. RUCO recommends a rate case expense of $950,000 normalized over three years.

Q. Do you agree with Staff and RUCO's recommendation?

A. No. Rate cases are complicated proceedings involving outside counsel and consultants. There are also costs for mailing and publishing notice. There is a significant amount of discovery that takes place. In addition to the application, there are three rounds of testimony prepared by the Company. There is a hearing and then post-hearing briefing, exceptions and open meeting. TEP believes that it is handling its rate cases in the most cost efficient manner possible as shown by its use of numerous internal personal for witnesses and rate case costs. TEP should be compensated for its actual costs.

Q. Do you have any other comments on this issue?

A. Yes. TEP's rate case involves 26 Interveners and 47 witnesses, and the Company has responded to over 3,000 data request. TEP incurred over $1 million in rate case expense in support of its 2012/2013 rate case even though that case ended in a settlement between the parties. UNS Electric is currently in a fully litigated rate case and has incurred over $1 million in rate case expense. Notably, the hearing in that case ran for a full 15 days, even though there revenue requirement issues were largely resolved prior to the hearing. Here, the hearing will likely be longer given the increased number of parties and witnesses, as well as the fact that there are numerous revenue requirement disputes in addition to the rate design disputes addressed in the UNS Electric case. TEP's request to recover $1.2 million in this proceeding reflects the increasing complexity of rate cases in Arizona.

D **Long Term Incentive Compensation.**

Q. Please explain the update to the Long Term Incentive Compensation pro-forma adjustment.

A. Company witness Frank Marino is supporting this adjustment. The revised adjustment increase operating income by $880,967.

E **Lime Costs.**

Q. Please explain the Lime Cost pro-forma adjustment.

A. This adjustment removes all of the Lime Cost associated with our jointly owned coal-fired generating facilities from non-fuel operating cost presently recovered through base rates and moves them to be recovered in the base cost of fuel. This is the same methodology that was approved in 2013 TEP Settlement Agreement which allowed TEP to recover lime expense associated with the Springerville generating station as a variable cost tied to fuel consumption and reconciled through the PPFAC (See settlement agreement section 6.2). This section clearly states that, lime cost associated with fuel consumption are to be recovered as a fuel cost for all of TEP's generation facilities. During the Company's last rate case proceeding, only the cost of lime associated with Springerville was available and, as a result, was the only amount removed from non-fuel operating cost in the "cost of service" as part of the 2013 TEP Settlement Agreement. As such, the lime cost for the Companies other coal-fired generating facilities remained a part of non-fuel costs. We propose to treat the lime costs at all coal-fired generating plants in a consistent manner to more accurately classifies and recover fuel-related costs through base cost of fuel rather than non-fuel rates.

Q. Why did TEP not make this adjustment in its direct filing?

A. It was an oversight not to include all lime costs incurred at all TEP's coal-fired generating facilities in the base fuel cost in the Company's initial filing. By moving the lime costs from the non-fuel component of base rates, this adjustment has a zero net impact to the cost of service.

F <u>Transmission Expense.</u>

Q. Please explain why the Transmission Expense increase operating income by $1.7 million in the Company's filed Rebuttal?

A. Sure, Transmission costs are recovered through base rates which reflect the transmission costs associated with serving retail customers. As a result of the Company reducing its annualized retail sales to reflect the curtailment of our largest customer's sight usage. This adjustment reduces the expected transmission costs in concurrence with the reduction in transmission revenues included in the adjusted test year revenues.

V. <u>CONCLUSION.</u>

Q. What is the Company's recommendation for revenue requirement?

A. TEP is requesting a revised increase in non-fuel base rates revenues of $100.6 million, or approximately 11 percent over adjusted retail electric revenues at current rates of $909.325 million.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit DJL – R – 1

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	$2,108,583,243	-	
Rate Base Adjustments						
Jurisdictional Allocation (Demand and Energy)	-	-	(138,422,327)	(32,996,491)	(32,996,491)	Impact of change to jurisdictional allocations except for impacts to rate base adjustments listed below.
SGS CHF	(41,966,722)	(41,966,722)	(41,966,722)	(41,239,083)	727,640	Impact of change to jurisdictional allocations
Fortis Merger Rate Base Adjustment	(522,398)	(522,398)	(522,398)	(517,560)	4,838	Impact of change to jurisdictional allocations
Asset Retirement Obligation	-	-	-	-	-	
Post Test Year Plant	51,782,029	37,124,629	-	51,003,979	(778,051)	Impact of change to jurisdictional allocations
Post Test Year Plant - Renewables	20,794,266	4,872,919	-	20,433,724	(360,541)	Impact of change to jurisdictional allocations
Delayed Unitization	13,237,543	13,237,543	13,237,543	13,118,186	(119,357)	Impact of change to jurisdictional allocations
Accumulated Deferred Investment Tax Credit (ITC)	30,341,626	30,341,626	30,341,626	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(58,303,521)	(58,308,686)	(57,662,694)	645,992	Impact of change to jurisdictional allocations
ADIT - Extension of Bonus Depreciation	-	(12,814,172)	-	(12,672,205)	(12,672,205)	ADIT related to extension of bonus depreciation
San Juan Unit 2	-	-	-	(0)	(0)	
Sundt Coal Handling facilities	(19,120)	880	(19,120)	(18,789)	332	Impact of change to jurisdictional allocations
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,855,471	6,855,471	6,736,607	(118,864)	Impact of change to jurisdictional allocations
Sundt & San Juan M&S	1,225,594	1,225,594	1,225,594	1,956,711	731,117	Increase is do to the revision of obsolete inventory at Sundt
Head Quarters	-	-	(55,043,003)	-	-	
Working Capital	(27,325,154)	(19,387,724)	(25,313,900)	(20,740,139)	6,585,016	Impact of changes to pro forma adjustments including $160K in jurisdictional allocation
Accumulated Depreciation adj and LTI	-	9,020,000	-	-	-	
Total Adjustments	(3,905,553)	(30,315,876)	(267,935,924)	(42,256,127)	(38,350,574)	
Pro Forma OCRB	2,104,677,690	2,078,267,367	1,840,647,319	2,066,327,116	(38,350,574)	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Proposed Rate of Return	7.34%	6.68%	6.76%	7.16%		
Required Operating Income OCRB	$154,416,180	$138,763,150	$124,427,759	$147,984,232	(6,431,948)	
Fair Value Increment of Rate Base	$808,601,055	$808,600,679	$741,672,017	791,549,067	(17,051,988)	
Fair Value Rate Base (FVRB)	$2,913,278,745	$2,886,869,000	$2,582,319,188	$2,857,876,183	(55,402,562)	
Proposed FVROR	5.69%	5.00%	5.20%	5.57%		
Required Operating Income on FVRB	165,898,315	144,418,355	134,398,160	159,224,227	(6,674,088)	
Implied ROR on Fair Value Increment of Rate Base	1.42%	0.70%	1.34%	1.42%		
Original Operating Income - Unadjusted	$318,271,141	$318,271,141	$318,271,141	$318,271,141		
Operating Income Adjustments						
Operating Revenue Adjustments						
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	(10,719,946)	-	
Environmental Cost Adjustor	(1,260,631)	(1,260,631)	(1,260,631)	(1,260,631)	-	
REST and DSM	(48,370,058)	(48,370,058)	(48,370,058)	(48,370,058)	-	
Non-Retail & Non Recurring Revenue	(112,150)	(112,150)	(112,150)	(112,150)	-	
Springerville Units 3 & 4	(111,813,089)	(111,813,089)	(111,813,089)	(111,813,089)	-	
Power Supply Management	(1,099,586)	(1,099,586)	(1,099,586)	(1,099,586)	-	
Customer, Weather and Recalculation of Unbilled Revenue	(4,791,733)	(4,791,733)	(3,956,411)	(4,791,733)	-	
Base Cost of Fuel & Purchased Power	(17,815,595)	(17,815,595)	(17,815,595)	(32,594,041)	(14,778,446)	Variance is due to a decrease in kWh sales (from 9,021M to 8,881M) and a decrease in the proposed PPFAC rate (from 3.3692 to 3.2559).

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Miscellaneous Service Revenue	284,370	284,370	284,370	284,370	-	
TEP Headquarters - Retail Space	250,000	250,000	250,000	250,000	-	
Total Adjustments to Operating Revenues	(195,448,418)	(195,448,418)	(194,613,096)	(210,226,864)	(14,778,446)	
Operating Expense Adjustments						
Jurisdictional Allocation (Demand and Energy)	-	-	(19,532,187)	(2,619,840)	(2,619,840)	Impact of change to jurisdictional allocations except for impacts to operating expense adjustments listed below.
REST and DSM	(19,891,996)	(19,891,996)	(19,891,996)	(19,769,956)	122,040	Impact of change to jurisdictional allocations
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,696,421)	(1,696,421)	(1,663,540)	32,881	Impact of change to jurisdictional allocations
Springerville Units 3 & 4	(84,382,546)	(84,382,546)	(84,382,546)	(83,129,337)	1,253,210	Impact of change to jurisdictional allocations
Sales of SO2 Allowances	47	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(278,075)	(278,075)	(276,646)	1,429	Impact of change to jurisdictional allocations
Base Cost of Fuel & Purchased Power	226,811,827	226,811,827	226,811,827	212,033,380	(14,778,447)	See explanation in Operating Revenues section.
Gila River O&M	6,130,964	6,130,964	6,130,964	6,024,663	(106,301)	Impact of change to jurisdictional allocations
Springerville Unit 1	(11,558,130)	(11,558,130)	(11,558,130)	(11,384,664)	173,466	Impact of change to jurisdictional allocations
SGS Unit 1 Non Fuel O&M (50.5% Share)	-	-	-	15,243,913	15,243,913	Addition of non-fuel operating costs associated with the 50.5% share of SGS Unit 1.
Overhaul & Outage Normalization	5,176,492	1,043,941	(870,213)	5,644,715	468,223	Increase is due to a formula error that understated the proposed outage expected and includes an offsetting jurisdictional allocation impact of ($90K).
Payroll Expense	2,264,794	1,121,186	2,264,794	2,250,757	(14,037)	Impact of change to jurisdictional allocations
Payroll Tax Expense	151,051	76,051	151,051	151,051	-	
Pension & Benefits	2,004,436	2,050,431	1,056,440	1,576,055	(428,381)	Removed SERP expense as proposed by Staff and RUCO.
Post-Retirement Benefits	1,339,160	1,339,160	1,339,160	1,339,160	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Short-Term Incentive Compensation	702,960	(2,803,734)	(2,964,033)	1,578,745	875,785	During discovery, the company inadvertently included $1,056,576 of capital cost in determining the levelized costs to FERC 920. By doing so, the amount requested was understated. The $875,785 is the result of correcting this understatement and includes an offsetting $11K due to the change in jurisdictional allocations.
Rate Case Expense	107,834	(36,208)	27,834	107,834	-	
Injuries and Damages	1,419	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(212,696)	(416,963)	(212,690)	6	Impact of change to jurisdictional allocations
Bad Debt Expense	(149,199)	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,921,687)	(3,921,687)	(3,869,457)	52,230	Impact of change to jurisdictional allocations
Long Term Incentive Compensation	880,967	-	(639,979)	-	(880,967)	Remove long term incentive compensation as proposed by Staff.
Depr. & Amort. Expense	9,253,715	(1,665,318)	(9,202,556)	1,542,840	(7,710,875)	Decrease is due to removal of 2% inflation for dismantlement costs, and a 5% future net salvage value for distribution assets. Includes a jurisdictional allocation impact of ($201K)
Post Test Year Plant Depreciation and Amortization	-	-	-	4,568,108	4,568,108	Increase is due to $4.6M in post test year plant and renewables that was inadvertentaly excluded in the original filing.
Sundt & San Juan M&S	408,531	408,531	408,531	652,237	243,706	Increase is due to an increase in obsolete Sundt coal handling inventory.
Property Tax Expense	3,119,696	2,694,696	2,554,799	3,119,770	74	Impact of change to jurisdictional allocations
Asset Retirement Obligation	(393,590)	(393,590)	(393,590)	(386,765)	6,825	Impact of change to jurisdictional allocations
SGS Common Facilities Lease	(1,195,980)	(1,195,980)	(1,195,980)	(1,175,244)	20,736	Impact of change to jurisdictional allocations
San Juan Unit 1 SCNR O&M	955,223	955,223	955,223	938,661	(16,562)	Impact of change to jurisdictional allocations
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	(31,176,174)	-	
Lime Expense				(1,612,486)	(1,612,486)	Company removed lime expense included in test year related to our jointly owned facility. These costs are recovered in base cost of fuel
TEP Headquarters	-	-	(942,257)	-	-	
Credit Card Processing Fees	3,475,500	-	-	-	(3,475,500)	Removed credit card processing fees as proposed by Staff and RUCO.

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Income Tax Expense	(16,130,352)	(5,695,687)	15,747,439	(19,049,439)	(2,919,086)	Reflects conformity changes and includes offsetting jurisdictional allocation impact of ($855K)
Transmission Expense Adjustment	95,464,952	95,464,952	95,464,952	93,719,409	(1,745,544)	Decrease in transmission expense reflects the impact of a usage reduction related to one of the Company's largest customers.
D&O Insurance	-	(25,000)	(25,153)	(21,105)	(21,105)	Accepted 50/50 sharing as proposed by RUCO and Staff.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	-	(548,924)	-	-	
Severance Pay	-	-	(329,665)	(329,665)	(329,665)	Removed severance pay as proposed by RUCO.
SGS Legal Expenses Lessor Dispute	-	(1,340,000)	-	-	-	
Total Adjustments to Operating Expense	24,441,665	8,854,929	(22,305)	10,845,501	(13,596,164)	
Total Net Adjustments	(219,890,083)	(204,303,347)	(194,590,791)	(221,072,365)	(1,182,282)	
Adjusted Operating Income	$98,381,058	$113,967,794	$123,680,350	$97,198,776	($1,182,282)	
Operating Income Deficiency	$67,517,257	$30,450,561	$10,717,810	$62,025,451	($5,491,806)	
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223	1.6223	1.6223	
Increase in Gross Revenue Requirement	$109,534,118	$49,400,339	$17,387,642	$100,624,690	($8,909,428)	

Exhibit DJL – R – 2

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	-	
Rate Base Adjustments					
Jurisdictional Allocation		(138,422,327)	(138,422,327)	-	
SGS CHF	(41,966,722)	(41,966,722)	(41,966,722)	-	
Fortis Merger Rate Base Adjustment	(522,398)	(522,398)	(522,398)	-	
Asset Retirement Obligation	-	-	-	-	
Post Test Year Plant	51,782,029	-	-	-	
Post Test Year Plant - Renewables	20,794,266	-	-	-	
Delayed Unitization	13,237,543	13,237,543	13,237,543	-	
Accumulated Deferred Investment Tax Credit (ITC)	30,341,626	30,341,626	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(58,308,686)	(53,547,344)	4,761,342	RUCO's adjustments to Rate Base did not include corresponding adjustments to ADIT. Company adjusted ADIT to reflect rate case adjustments as proposed by RUCO.
San Juan Unit 2	-	(0)	(0)	-	
Sundt Coal Handling facilities	(19,120)	(19,120)	(19,120)	-	
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,855,471	6,855,471	-	
Sundt & San Juan M&S	1,225,594	1,225,594	1,225,594	-	

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Head Quarters		(55,043,003)	(55,043,000)	3	
Working Capital	(27,325,154)	(25,313,900)	(27,351,091)	(2,037,191)	RUCO adjusted Company's Cash Working Capital worksheet to reflect RUCO"s adjustments using ACC jurisdictional values. However, the Company's Cash Working Capital worksheet uses pre-ACC jurisdictional values, then adjusts for the ACC jurisdictional ratio by the Revenue Requirements Model. Company corrected RUCO's Cash Working Capital worksheet to reflect pre-ACC jurisdictional values.
Total Adjustments	(3,905,553)	(267,935,924)	(265,211,769)	2,724,155	
Pro Forma OCRB	2,104,677,690	1,840,647,319	1,843,371,474	2,724,155	
Proposed Rate of Return	7.34%	6.76%	6.76%		
Required Operating Income OCRB	$154,416,180	$124,427,759	$124,611,912	184,153	
Fair Value Increment of Rate Base	$808,601,055	$741,672,017	$738,947,714	(2,724,303)	
Fair Value Rate Base (FVRB)	$2,913,278,745	$2,582,319,188	$2,582,319,188	-	
Proposed FVROR	5.69%	5.20%	5.21%		
Required Operating Income on FVRB	165,898,315	134,398,160	134,546,280	148,120	
Implied ROR on Fair Value Increment of Rate Base	1.42%	1.34%	1.34%		

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Original Operating Income - Unadjusted	$318,271,141	$318,271,141	$318,271,141		
Operating Income Adjustments					
Operating Revenue Adjustments					
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	-	
Environmental Cost Adjustor	(1,260,631)	(1,260,631)	(1,260,631)	-	
REST and DSM	(48,370,058)	(48,370,058)	(48,370,058)	-	
Non-Retail & Non Recurring Revenue	(112,150)	(112,150)	(112,150)	-	
Springerville Units 3 & 4	(111,813,089)	(111,813,089)	(111,813,089)	-	
Power Supply Management	(1,099,586)	(1,099,586)	(1,099,586)	-	
Customer, Weather and Recalculation of Unbilled Revenue	(4,791,733)	(3,956,411)	(3,956,411)	-	
Base Cost of Fuel & Purchased Power	(17,815,595)	(17,815,595)	(17,815,595)	-	
Miscellaneous Service Revenue	284,370	284,370	284,370	-	
TEP Headquarters - Retail Space	250,000	250,000	-	(250,000)	RUCO removed the entire value of the building including the value of the retail space. Since the retail space is no longer in rate base, Company eliminated the rent credit to avoid RUCO's double counting.
Total Adjustments to Operating Revenues	(195,448,418)	(194,613,096)	(194,863,096)	(250,000)	
Operating Expense Adjustments					

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
REST and DSM	(19,891,996)	(19,891,996)	(19,891,996)	-	
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,696,421)	(1,696,421)	-	
Springerville Units 3 & 4	(84,382,546)	(84,382,546)	(84,382,546.45)	-	
Sales of SO2 Allowances	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(278,075)	(278,075)	-	
Base Cost of Fuel & Purchased Power	226,811,827	226,811,827	226,811,827	-	
Gila River O&M	6,130,964	6,130,964	6,130,964	-	
Springerville Unit 1	(11,558,130)	(11,558,130)	(11,558,130)	-	
Overhaul & Outage Normalization	5,176,492	(870,213)	4,419,896	5,290,109	The correction has two parts. The first is to correct for RUCO's math error. RUCO's adjustment was intended to levelize expenses to $8,177,594. However, RUCO levelized expense to $9,165 ,217. The second adjustment is to correct the frequency percent. RUCO's intention was to use a levelized frequency percentage over 11 years, however, their formula was averaging over 17 years.
Payroll Expense	2,264,794	2,264,794	2,264,794	-	
Payroll Tax Expense	151,051	151,051	151,051	-	
Pension & Benefits	2,004,436	1,056,440	1,576,055	519,615	RUCO did not include additional benefits included in revised pro forma adjustment. Company corrected for revised pro forma.
Post-Retirement Benefits	1,339,160	1,339,160	1,339,160	-	

TUCSON ELECTRIC POWER					
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT					
TEST YEAR ENDED JUNE 30, 2015					
ACC JURISDICTION					
	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Short-Term Incentive Compensation	702,960	(2,964,033)	(2,964,033)	-	
Rate Case Expense	107,834	27,834	40,708	12,874	RUCO did not use the ACC jurisdictional adjusted values in the adjustment. Company corrected RUCO's adjustment.
Injuries and Damages	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(416,963)	(406,087)	10,876	RUCO applied the same ACC jurisdictional ratio to all EEI adjustments. The ACC jurisdictional ratio varied on some EEI charges.
Bad Debt Expense	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,921,687)	(3,921,687)	-	
Long Term Incentive Compensation	880,967	(839,979)	(431,510)	208,469	RUCO removed LTI based on company's revised/corrected pro forma. Since the correction was not included in the model, RUCO should have used the originally filed pro forma adjustment to remove LTI. Also, RUCO applied payroll tax at a rate of 7.65%. The payroll tax rate on LTI should be 1.45%.
Depr. & Amort. Expense	9,253,715	(9,202,556)	(5,499,223)	3,703,333	RUCO removed 12 months of depreciation expense for both post test year and post test year renewables. By doing so RUCO doubled the expense related to non revewable to post year year.
Sundt & San Juan M&S	408,531	408,531	408,531	-	
Property Tax Expense	3,119,696	2,554,799	2,554,799	-	
Asset Retirement Obligation	(393,590)	(393,590)	(393,590)	-	
SGS Common Facilities Lease	(1,195,980)	(1,195,980)	(1,195,980)	-	
San Juan Unit 1 SCNR O&M	955,223	955,223	955,223	-	
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
TEP Headquarters	-	(942,257)	2,948,646	3,890,903	RUCO removed deprecation expense related to new building. Treated HQ building as owned by UNS and calculated rent at "the going market rate." Company correction included the removal of HQ building from rate base and allow $5.3M of annual rent expense.
Credit Card Processing Fees	3,475,500	-	-	-	
Income Tax Expense	(16,130,352)	15,747,439	12,579,068	(3,168,371)	Reflects impact of corrected pro forma postions including a jurisdictional allocation change of $8,577,635.
Transmission Expense Adjustment	95,464,952	95,464,952	95,464,952	-	
Jurisdictional Allocation	-	(19,532,187)	(19,532,187)	-	
D&O Insurance	-	(25,153)	(21,105)	4,048	RUCO did not use the ACC jurisdictional adjusted value in the adjustment. Company corrected RUCO's adjustment.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	(548,924)	(521,442)	27,482	RUCO did not use the ACC jurisdictional adjusted value for wellness expenses in the adjustment. Company corrected RUCO's adjustment.
Severance Pay - New		(329,665)	(238,519)	91,146	RUCO incorrectly included portion of severance pay that was capitalized in the amount disallowed (O&M = $217K, Capitalized=$112, Sum $329).
Total Adjustments to Operating Expense	24,441,665	(22,305)	10,568,179	10,590,484	
Total Net Adjustments	(219,890,083)	(194,590,791)	(205,431,275)	(10,840,484)	
Adjusted Operating Income	$98,381,058	$123,680,350	$112,839,866	($10,840,484)	
Operating Income Deficiency	$67,517,257	$10,717,810	$21,706,414	$10,988,604	
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223	1.6223	
Increase in Gross Revenue Requirement	$109,534,118	$17,387,642	$35,214,596	$17,826,954	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected

Exhibit DJL – R – 3

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	$0	
Rate Base Adjustments					
Jurisdictional Allocation (Demand and Energy)	-	-	-	-	
SGS CHF	(41,966,722)	(41,966,722)	(41,966,722)	-	
Fortis Merger Rate Base Adjustment	(522,398)	(522,398)	(522,398)	-	
Asset Retirement Obligation	-	-	-	-	
Post Test Year Plant	51,782,029	37,124,629	37,124,629	-	
Post Test Year Plant - Renewables	20,794,266	4,872,919	4,872,919	-	
Delayed Unitization	13,237,543	13,237,543	13,237,543	-	
Accumulated Deferred Investment Tax Credit (ITC)	30,341,626	30,341,626	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(58,303,521)	(53,004,227)	5,299,294	Staff's adjustments to rate base did not include corresponding adjustments to ADIT. Company adjusted ADIT to reflect rate case adjustments as proposed by Staff.
ADIT - Extension of Bonus Depreciation	-	(12,814,172)	(12,814,172)	-	
San Juan Unit 2	-	-	-	-	
Sundt Coal Handling facilities	(19,120)	880	880	-	
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,855,471	6,855,471	-	
Sundt & San Juan M&S	1,225,594	1,225,594	1,225,594	-	
Head Quarters	-	-	-	-	
Working Capital	(27,325,154)	(19,387,724)	(19,122,961)	264,763	Staff adjusted Company's Cash Working Capital worksheet to reflect Staff's adjustments using ACC jurisdictional values. However, the Company's Cash Working Capital worksheet uses pre-ACC jurisdictional values, then adjusts for the ACC jurisdictional ratio via the Revenue Requirements Model. Company corrected Staff's Cash Working Capital worksheet to reflect pre-ACC jurisdictional values.
Accumulated Depreciation adj and LTI	-	9,020,000	-	(9,020,000)	The average remaining life as used in the Company's depreciation study is self correcting. Thus, no adjustment is necessary. Reducing the reserve balance overstates the asset value on which the Company is earning a return.
Total Adjustments	(3,905,553)	(30,315,876)	(33,771,819)	(3,455,943)	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
Pro Forma OCRB	2,104,677,690	2,078,267,367	2,074,811,424	5,564,057	
Proposed Rate of Return	7.34%	6.68%	6.68%		
Required Operating Income OCRB	154,416,180	138,763,150	$138,532,390	(230,760)	
Fair Value Increment of Rate Base	808,601,055	808,600,679	$803,994,234	(4,606,445)	
Fair Value Rate Base (FVRB)	2,913,278,745	2,886,869,000	$2,878,806,457	(8,062,543)	
Proposed FVROR	5.69%	5.00%	5.00%		
Required Operating Income on FVRB	165,898,315	144,418,355	$144,155,350	(263,005)	
Implied ROR on Fair Value Increment of Rate Base	1.42%	0.70%	0.70%		
Original Operating Income - Unadjusted	318,271,141	318,271,141	$318,271,141	$0	
Operating Income Adjustments					
Operating Revenue Adjustments					
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	-	
Environmental Cost Adjustor	(1,260,631)	(1,260,631)	(1,260,631)	-	
REST and DSM	(48,370,058)	(48,370,058)	(48,370,058)	-	
Non-Retail & Non Recurring Revenue	(112,150)	(112,150)	(112,150)	-	
Springerville Units 3 & 4	(111,813,089)	(111,813,089)	(111,813,089)	-	
Power Supply Management	(1,099,586)	(1,099,586)	(1,099,586)	-	
Customer, Weather and Recalculation of Unbilled Revenue	(4,791,733)	(4,791,733)	(4,791,733)	-	
Base Cost of Fuel & Purchased Power	(17,815,595)	(17,815,595)	(17,815,595)	-	
Miscellaneous Service Revenue	284,370	284,370	284,370	-	
TEP Headquarters - Retail Space	250,000	250,000	250,000	-	
Total Adjustments to Operating Revenues	(195,448,418)	(195,448,418)	(195,448,418)	-	
Operating Expense Adjustments					
Jurisdictional Allocation (Demand and Energy)	-	-	-	-	
REST and DSM	(19,891,996)	(19,891,996)	(19,891,996)	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,696,421)	(1,696,421)	-	
Springerville Units 3 & 4	(84,382,546)	(84,382,546)	(84,382,546)	-	
Sales of SO2 Allowances	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(278,075)	(278,075)	-	
Base Cost of Fuel & Purchased Power	226,811,827	226,811,827	226,811,827	-	
Gila River O&M	6,130,964	6,130,964	6,130,964	-	
Springerville Unit 1	(11,558,130)	(11,558,130)	(11,558,130)	-	
SGS Unit 1 Non Fuel O&M (50.5% Share)	-	-	-	-	
Overhaul & Outage Normalization	5,176,492	1,043,941	1,043,941	-	
Payroll Expense	2,264,794	1,121,186	1,121,186	-	
Payroll Tax Expense	151,051	76,051	76,051	-	
Pension & Benefits	2,004,436	2,050,431	1,576,433	(473,998)	The test year had $564,903 reflected in FERC 926 and $564,904 in FERC 426. The Company's pro forma moved the amounts reflected in FERC 426 (below the line) to FERC 926. Staff intended to remove 100% of SERP, but inadvertently only removed the amount reflected in FERC 426. Staff adjustment includes the revised pension and benefit amount as identified by the Company ($2,529,050)
Post-Retirement Benefits	1,339,160	1,339,160	1,339,160	-	
Short-Term Incentive Compensation	702,960	(2,803,734)	(2,803,734)	-	
Rate Case Expense	107,834	(36,208)	(36,208)	-	
Injuries and Damages	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(212,696)	(212,696)	-	
Bad Debt Expense	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,921,687)	(3,921,687)	-	
Long Term Incentive Compensation	880,967	-	-	-	
Depr. & Amort. Expense	9,253,715	(1,665,318)	(1,588,163)	77,155	Staff assumes a 1 to 1 relationship on ACC jurisdictional ratios for post test year plant accumulated depreciation and depr. expense. ACC jurisdictional ratios are different.
Post Test Year Plant	-	-	-	-	
Sundt & San Juan M&S	408,531	408,531	408,531	-	
Property Tax Expense	3,119,696	2,694,696	2,694,696	-	
Asset Retirement Obligation	(393,590)	(393,590)	(393,590)	-	
SGS Common Facilities Lease	(1,195,980)	(1,195,980)	(1,195,980)	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
San Juan Unit 1 SCNR O&M	955,223	955,223	955,223	-	
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	-	
Lime Expense	-	-	-	-	
Credit Card Processing Fees	3,475,500	-	-	-	
Income Tax Expense	(16,130,352)	(5,695,687)	(5,591,094)	104,594	Impact of Company corrections to Staff adjustments.
Transmission Expense Adjustment	95,464,952	95,464,952	95,464,952	-	
D&O Insurance	-	(25,000)	(21,105)	3,895	Staff did not use the pre-ACC jurisdictional ratio amount to adjust for the elimination of 50% of D&O insurance. Company corrected staff's adjustment by eliminating 50% of ACC jurisdictional D&O insurance amount.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	-	-	-	
Severance Pay	-	-	-	-	
SGS Legal Expenses Lessor Dispute	-	(1,340,000)	(1,124,730)	215,270	Staff's adjustment is a total Company position. The $215,270 is to reflect the portion not allocable to all jurisdictions.
Total Adjustments to Operating Expense	24,441,665	8,854,929	8,781,845	(73,084)	
Total Net Adjustments	(219,890,083)	(204,303,347)	(204,230,263)	73,084	
Adjusted Operating Income	$98,381,058	$113,967,794	$114,040,878	$73,084	
Operating Income Deficiency	$67,517,257	$30,450,561	$30,114,472	($336,089)	
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223	1.6223	
Increase in Gross Revenue Requirement	$109,534,118	$49,400,339	$48,855,097	($545,242)	

Exhibit DJL – R – 4

RUCO 11.02

Post Test Year Plant – Has the Company utilized the half-year convention when calculating accumulated depreciation on Post Test Year Plant?

RESPONSE:

The accumulated depreciation reflects a full year depreciation expense on the post-test year adjustment.

RESPONDENT:

Bernadette Porter

WITNESS:

Dallas Dukes

Exhibit DJL – R – 5

TUCSON ELECTRIC COMPANY
POST TEST YEAR
TEST YEAR ENDING JUNE 30, 2015

EXHIBIT DJL - R - 5

FERC	Project	Project Name	In Service Dates (A)	Post Test Year (B)	Total Depreciation (C)	ACC Juris. Ratio (D)	ACC Post Test Year Amount ('E)	ACC Depreciation (F)	NBV (G)
Projects Unitized									
	General								
303	D141OSP	Oracle Services Procurement	MAY-16	380,252	380,252	92.03%	349,945	349,945	-
303	D141AFR	2014 Acct Financial Reporting	MAY-16	2,365,016	450,479	92.03%	2,176,525	414,576	1,761,949
	Generation								
312	D14AD79	Selective Non-Catalytic Reduc	APR-16	9,774,013	257,057	89.78%	8,775,108	230,785	8,544,323
312	D13SK02	SGS U2 Mercury	MAY-16	1,075,679	21,729	89.78%	965,745	19,508	946,237
312	D13SE01	SGS U1 Mercury	MAR-16	498,459	8,673	89.78%	447,517	7,787	439,730
315	D02AB96	Irv #3 Step Transformer Replmt	JUN-16	1,660,946	204,462	89.78%	1,491,197	183,566	1,307,631
315	D08AB07	Sundt U3 MCC Replacement	JUN-16	258,865	31,938	89.78%	232,409	28,674	203,735
	Distribution								
362	D11DD93	NE T2A Swtchgr Replc	JAN-16	131,864	2,374	100.00%	131,864	2,374	129,491
		Sub-Total Projects Unitized		16,145,094	1,356,963		14,570,310	1,237,216	13,333,095
Projects Pending									
	Generation								
311	D13AC90	Sundt Cooling Tower Blowdown	DEC-16	158,920	16,758	89.78%	142,679	15,045	127,633
312	D12AC77	Sundt Condensate tank Piping	DEC-16	277,508	28,930	89.78%	249,147	25,974	223,173
312	D05AD32	San Juan Various Enviro Projs	DEC-16	220,886	7,786	89.78%	198,311	6,990	191,321
	Distribution								
362	D14NM15	Volt-Var Pilot Ph1 & 2	DEC-16	553,547	9,964	100.00%	553,547	9,964	543,583
362	D09EO02	Wilmot T2 Replacement	DEC-16	130,583	2,350	100.00%	130,583	2,350	128,232
367	D13LE28	RV- Tangerine West 3rd Fdr Tie	DEC-16	112,774	2,413	100.00%	112,774	2,413	110,360
		Sub-Total Projects Pending		1,454,218	68,202		1,387,041	62,737	1,324,303
		Grand Total		17,599,312	1,425,166		15,957,351	1,299,953	14,657,398
	Renewables								
344	D14PD43	Brt Buildout Plan Ft Huachuca Phase II	Aug-16	8,200,000	210,330	89.78%	7,361,960	188,834	7,173,126
344	NA	TEP Community Solar-Pima Cnty	SEP-16	10,000,000	256,500	89.78%	8,978,000	230,286	8,747,714
				18,200,000	466,830		16,339,960	419,120	15,920,840
			Grand Total	34,345,093.85	1,823,793.26		32,297,311.01	1,719,072.81	30,578,238.20

Exhibit DJL – R – 6

STAFF'S RESPONSE TO TUCSON ELECTRIC POWER COMPANY'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION UTILITIES DIVISION STAFF
DOCKET NO. E-01933A-15-0322
JUNE 24, 2016

Data Requests Regarding Direct Testimony of ACC Staff Witness Donna Mullinax

TEP 2.1: Regarding Ms. Mullinax's recommendation to limit Post Test Year Plant to plant that was in service by December 31, 2015. (Mullinax Direct at pages 8-9):

A. Does Staff agree that no ACC rule limits Post Test Year Plant to plant that was in service six months after the end of the test year. If not, please explain why not.

RESPONSE: **Staff agrees.**

RESPONDENT: Donna Mullinax

B. Does Staff agree that no written ACC policy limits Post Test Year Plant to plant that was in service six months after the end of the test year. If not, please explain why not.

RESPONSE: **Staff agrees.**

RESPONDENT: Donna Mullinax

C. Does Staff agree that in *EPCOR Water Arizona, Inc.*, Decision No. 75268 (Sep. 8, 2015), the Commission rejected RUCO's request to limit Post Test Year Plant to plant that was in service six months after then end of the test year. (See pages 16 to 17 of that Decision). If not, please explain why not.

RESPONSE: **Staff agrees that in the referenced *EPCOR Water Arizona, Inc.* case, Staff recommended the inclusion of Post Test Year plant additions that were completed by the end of the test year but were treated as CWIP, in addition to inclusion of projects that were still in CWIP but were completed by June 30, 2014 (Test Year - 12 months ended June 30, 2013). Staff stated that Commission rules contemplate the inclusion of Post Test Year plant in rate**