9. PSO's proposed rate increase has been increased by $1.2 million compared to Direct Testimony due primarily to updating rate base to actual six-months post test year and the acceptance of some proposed adjustments by other parties. PSO has also addressed all of the other parties' proposed adjustments to its recovery of costs in Rebuttal Testimony, and continues to believe the adjusted request for rate relief is reasonable, necessary, and should be granted by the Commission.

Mr. Fate summarized his rebuttal to OIEC witness Garrett as follows:

1. Mr. Garrett states that the Company should not be allowed to recover its investment or earn a return on Northeastern Unit 4 because is it not "used and useful." – I have been advised by counsel that Mr. Garrett's argument relies on incorrect application of case law. His industry examples are materially different than the fact scenario for Northeastern Unit 4 and therefore are not applicable.

2. Mr. Garrett argues that regulatory precedent exists in other states where commissions have denied recovery of the cost of retired coal plants – Each jurisdiction and case has its own set of facts and there are many examples of situations similar to Unit 4 where state utility commissions have approved full recovery of and return on retired coal plants.

3. Mr. Garrett states there is no order, case law or statute where costs associated with an asset that is "voluntarily" retired has been classified as "stranded" and since Unit 4 was "voluntarily" retired, the costs are not "stranded." – The argument of whether an investment falls under a narrowed definition of "stranded" is moot. The question for this Commission is should investors be allowed to recover and earn a return on the undepreciated book value of an asset that served customers for 36 years and then was retired to be in compliance with state and federal law.

4. Mr. Garrett presents a single data point out of the many scenarios and sensitivities under which PSO analyzed its environmental compliance options in an attempt to demonstrate the ECP does not benefit customers – The Company conducted a thorough and robust analysis, considering a multitude of costs and risks and concluded that the ECP is a reasonable alternative given the numerous and necessary difficult long-term assumptions. When fairly considering and balancing all the risks and mitigating factors, the ECP is a reasonable low risk, low cost option. The PUD's and AG's expert witness in Cause No. PUD 201200054, Dr. Craig Roach of Boston Pacific, concluded, "PSO demonstrated the prudence of its choice of the EPA Settlement through its extensive evaluation of the alternatives in Cause 54." Moreover, Mr. Garrett's arguments are moot given that the Commission found the plan prudent and that reasonable costs associated with the plan should be recoverable.

5. Mr. Garrett believes that customers should not have to bear the cost of Unit 4 since the Company made a decision that was not least cost for customers and the decision was made so that benefits could inure to the Company – There is no evidence that the decision inured to the benefit of the Company. Rather there is substantial evidence the Company lost significant earnings opportunity by avoiding the investment necessary to install scrubbers on both Northeastern coal units.

6. Mr. Garrett contends that the Commission has several options for partial cost recovery such as used in the Black Fox nuclear plant order and the OG&E Arbuckle plant – The examples discussed by Mr. Garrett are factually very different than Northeastern Unit 4. In the case of Black Fox the unit never reached operation unlike Northeastern Unit 4 which served customers for 36 years. In the case of the OG&E Arbuckle plant it was mothballed, placed in the FERC account for Electric Plant Held for Future Use, rather than retired like Northeastern Unit 4.

7. Mr. Garrett argues that the Commission was wrong when it set the original depreciation rates for Northeastern Units 3 & 4 and that the Commission's decision in 2006 to change their usefully lives to 60 years is indelibly correct – The estimated useful life of an asset must frequently be reassessed when circumstances change. In the case of Unit 4, the useful life was ultimately determined by environmental compliance requirements and not an estimate made back in 2006 before the full impact of Regional Haze Rule (RHR) and the Mercury and Air Toxics Standard (MATS) was known.

Mr. Fate summarized his rebuttal to AG witness Mr. Bohrmann by stating that:

1. Mr. Bohrmann states that the Commission's prior approval of the Company's Environmental Compliance Plan intentionally left the issue of Unit 4 cost recovery open for future review – Regardless of Mr. Bohrmann's characterization of the Commission's intent in their order in the 2015 Rate Case, PSO's argument is about consistency – that to not allow the full recovery of and return on Unit 4 would be fundamentally inconsistent with the Commission's prior findings in Cause No. PUD 201500208 where they approved cost recovery for the NOx controls and Oklaunion, and where they found the ECP prudent.

2. Mr. Bohrmann argues that the Commission's original ruling in 1981 that Unit 4 was "used and useful" is not relevant on a going-forward basis – Up until 2006 the Commission's authorized deprecation rate for Unit 4 was based on it remaining in service for 31 years. The Commission decided in 2006 to extend the depreciable life to 2040 when 31 years has now proven to be closer to the actual life of the unit. It would now be inappropriate for the Commission to deny full recovery of the investment.

3. Mr. Bohrmann believes the Company voluntarily retired Unit 4 resulting in the unit no longer being used and useful once it retired – The Company did not voluntarily retire Unit 4. It was part of an overall plan to bring PSO's generating fleet into compliance with RHR and MATS. But for these federal environmental laws PSO would not have been required to implement any of the compliance measures. Mr. Bohrmann even admits that Northeastern Unit 3 could not be operating if Unit 4 remained in service. Thus, in that sense, Unit 4's retirement is necessary to keep Unit 3 running and is therefore used and useful and serving customers.

4. Mr. Bohrmann suggests it is necessary to incent the Company to maximize the use of retired Unit 4 the Company should be allowed to earn a return on only components in common with Unit 3 or where salvaged and used elsewhere in PSO's generating fleet – The so-called incentive is not effective. The proposal to allow materials and equipment from Unit 4 in rate base to the extent they are used elsewhere to serve PSO customers is nothing more than what PSO would receive under normal cost recovery.

Mr. Fate did not agree with Attorney General witnesses Edwin C. Farrar and James B. Alexander who made recommendations based specifically on the goal of reducing the impact to current customers.

Mr. Fate testified that: first, for reasons similar to what he made in his direct testimony related to reasonable depreciation rates, it is unfair to future customers to pay for service provided to current customers. Deferring current expenses to future customers completely ignores the fundamental ratemaking concepts of intergenerational equity and cost causation. To a significant degree, the size of the requested increase in this case is a result of prior actions that have resulted in deferral of reasonable cost recovery to serve current customers. To further defer current expenses on the back of future customers will increase overall cost to customers and compound the increase experienced by future customers who will be required to pay for not only the services they receive but for services rendered to prior customers. Continued deferral of reasonably incurred expenses also creates cash flow difficulties for the Company and makes it more difficult to fund the necessary investments the Company needs to make to continue the high level of service our customers currently enjoy.

According to Mr. Fate, Mr. Farrar argues that current costs to serve customers should be deferred because customers in the future will have greater financial wherewithal to pay for the increase due to wage growth. Mr. Farrar also claims that the Company can change its capital structure by financing large projects with debt only, and thereby lowering the Company's overall cost of capital and reducing rates. Finally, he makes the suggestion that the Commission can simply ignore the Company's requested increase by implementing a phase in over three years.

Mr. Fate testified that deferring cost recovery to future customers would be inappropriate. Moreover, the notion that customers can afford to pay more for the electrical service in the future because of wage growth ignores the fact that (1) all else being equal the cost to serve customers will also be increasing at a similar inflation rate, and (2) generally it is more costly to customers over the long run when recoverable costs are deferred.

Mr. Fate testified that Mr. Farrar's suggestion that the Company can finance new projects with only debt, thereby reducing its cost of capital is a false claim. In effect, Mr. Farrar is suggesting the company increase its debt leverage under a false pretense that the investment community will ignore the increased financial risk. To the contrary, investors will not ignore the increased financial risk represented in the increased debt leverage of the Company and will impute an increase risk to the Company's capital.

Finally, while the simplistic notion that the Commission should phase in over several years the requested rate increase ignores the Company's need to recover reasonable expenses in a timely manner and the financial harm that would result if it is not allowed to do so. If the Company were to be kept financially indifferent to such a phase in plan, customers' rates would be higher in the long term than if the Commission grants PSO the relief requested in this cause.

Mr. Fate testified that Mr. Alexander states that the requested increase in storm expense in base rates be denied "given the magnitude of the rate increase requested in this case."

According to Mr. Fate, the amount in base rates has not been adjusted since the $2.8 million in base rates was set back in 2008. It clearly needs to be reset based on more current levels of storm damage costs and can be reviewed again in the future if average costs change.

Mr. Fate did not agree with OIEC witness Garrett and AG Witness Farrar characterization of the Company's support for SPP expenses as inadequate. PSO fully supported the reasonableness of the SPP expenses. Contrary to the accounts of Mr. Farrar and Mr. Garrett, three PSO witnesses (Mr. Hamlett, Mr. Ross and Mr. Smith) provided support for the SPP charges in direct testimony.

According to Mr. Fate, as Mr. Hamlett discusses in his rebuttal, in addition to providing narrative and a table detailing each SPP pro-forma adjustment in his direct testimony, he also submitted multiple workpapers thoroughly supporting the charges. While both Garrett and Farrar discuss the testimony of Mr. Hamlett to a degree, they do not acknowledge the vast amount of data provided in the workpapers and supporting documentation.

It is common practice in a rate case to support adjustments with narrative and to then supply more detailed support through workpapers and schedules. This is an accepted approach, because often, as is the case here, workpapers are voluminous spreadsheets and including them in filed testimony is often impractical.

PUD Witness Jason Chaplin's responsive testimony illustrates this common practice. In his testimony he details the process that he used and the information he reviewed to verify the reasonableness of the SPP charges, including his review of the aforementioned workpapers.

Mr. Fate further testified that although both Mr. Garrett and Mr. Farrar make no mention of Mr. Smith's testimony, it provides substantial support for the test year adjustment by describing the expenses contained within Account 565 and detailing the projects booked there. (Account 565 makes up the majority of the test year increase.) More specifically, beginning on page 21, he details the twelve largest projects and explains why they were completed. Beginning on page 25, Mr. Smith also discusses the transmission planning services provided by SPP and the benefits that the transmission system expansion brings to customers.

Mr. Fate testified that Mr. Garrett states on page 64 of his responsive testimony that Mr. Ross's testimony "does not support the specific test year adjustments to SPP expenses... ." While it is true that Mr. Ross's direct testimony does not mathematically support the SPP pro forma, it does provide critical support related to the reasonableness of the expenses. However, Mr. Garrett dismisses this support, and in doing so, appears to miss the main point of Mr. Ross's testimony. In the purpose section on page three of Mr. Ross's testimony he states, "I will discuss how PSO, through representation by AEP and PSO staff, actively participates in the SPP stakeholder groups, which provide oversight to the SPP transmission planning and other activities so that the projects constructed and activities performed by SPP are done in a manner that is reasonable and beneficial." The details of PSO's participation in the stakeholder groups are key in supporting the reasonableness of the SPP costs because stakeholder groups exist to provide additional oversight of the SPP process to "ensure PSO (and its customers) pay the lowest reasonable costs for the services it procures from the SPP." Mr. Garrett also ignores Section VI. of Mr. Ross's testimony entitled "Reasonable Costs and Benefits to PSO Customers" where Mr. Ross details the steps taken to ensure that the costs paid by PSO customers are reasonable.

Mr. Fate further testified that in addition to attacking the reasonableness of the SPP test year adjustment, Mr. Garrett also claims that PSO failed to comply with the requirements of the Southwest Power Pool Transmission Cost Tariff (SPPTC) and should therefore be required to refund the $42.88 million of charges collected through the SPPTC during the test year.

According to Mr. Fate, Mr. Garrett's claim is without merit. Please refer to the testimony of PUD Witness Mr. Chaplin for a description of the substantial information supporting the charges collected through the SPPTC which was made available to all parties in this cause. Note that the SPPTC requirement to support the reasonableness of the charges collected during the test year in a rate case is the same information provided to PUD each year during the annual SPPTC factor true-up. Consequently, before PSO changes the annual SPPTC factor, a thorough filing package is submitted to PUD prior to approval and implementation of that factor. The same contents of that filing package (for the test year) were provided to parties in this cause.

ANDREW R. CARLIN

Mr. Carlin submitted rebuttal testimony. He responded to AG Witness Farrar, OIEC Witness M. Garrett. According to Mr. Carlin, their arguments ignore that PSO's operating performance is the primary factor in determining PSO incentive compensation, which despite the earnings multiplier would not be paid if PSO did not meet the operational goals directly benefitting customers. Their arguments also ignore the fundamental purpose of the Company's incentive compensation, which is to provide market competitive compensation which enables the Company to attract, motivate, engage and retain the suitably experienced and skilled employees needed to efficiently and effectively provide its service to customers. The Company's incentive compensation provides these substantial benefits to customers.

Mr. Carlin testified that no party to this case disputes that the total compensation the Company provides to its employees is market competitive, reasonable and fair. In fact, witness Rush states that:

> If incentive plans were eliminated, and those dollars were inserted as base salary instead, compensation would still be in a range that is competitive with compensation packages provided by other like-sized companies.

Further, no party disputes the need for the Company to provide market competitive compensation in order to attract and retain a suitably skilled and experienced workforce and thereby efficiently and effectively provide quality electric service to customers. It is inappropriate to disallow the expense of incentive compensation that is undisputedly both reasonable and necessary for the provision of electrical service to customers and therefore, highly beneficial to customers, particularly when the benefits associated with such incentive compensation have and will continue to inure to customers.

Mr. Carlin testified that the Commission should consider that more recent rulings for gas utilities provided full recovery of incentive compensation. While the gas utilities subject to the orders approving full recovery of annual and long-term incentive compensation each have performance-based rate mechanisms, PSO's compensation practices are not materially different and align with customer interests for the same reasons cited in these Commission orders.

Mr. Carlin also testified that the change in the PUD's recommended treatment of incentive compensation is also notable. PUD now recommends inclusion of 100% of short-term incentives and 25% of long-term incentives because "PUD believes that it is prudent for the Company to have a comprehensive incentive plan, including both short-term and long-term incentives, as an important part of employee attraction and retention." PUD understands that "If incentive plans were eliminated, and those dollars were inserted as base salary instead, compensation would still be in a range that is competitive with compensation packages provided by other like-sized companies. As such, a portion of the expense for incentive compensation should be recovered from consumers. PUD recommends that the Commission should allow 100% of Short-Term Incentive Compensation in the amount of $12,488,266.48, and allow 25% of Long-Term Incentive Compensation in the amount of $1,086,491"

Mr. Carlin testified that the Company's annual incentive program provides substantial benefits to customers at no incremental cost above the cost of providing market-competitive compensation through base pay alone. None of the performance measures therein have been shown to be detrimental to customer interests on the whole. Furthermore, no party has challenged the Company's compensation levels relative to market or the critical role that incentive compensation plays in maintaining the competitiveness of these levels. As such, 100 percent of the Company's incentive compensation expense is a just, reasonable and necessary cost for the efficient and effective delivery of the electric service to its customers. Therefore, the Company requests that 100 percent of the target level of annual incentive compensation be included in the Company's cost of service, which is the level required for the provision of market-competitive compensation. The Company is reasonably and fairly requesting to include only the target level in rates and for the Company and its stockholders to assume 100% of the financial risk and expense associated with above target performance.

Mr. Carlin testified that Witness M. Garrett proposes to remove 50 percent of the Company's short-term incentive compensation and 100 percent of the Companies' long-term incentive compensation from rate base because he argues that the treatment of capitalized incentive compensation should be consistent with the treatment of incentive compensation in the Company's cost of service for rate making purposes. The impact of this proposal, if adopted, would be to immediately eliminate the Company's ability to earn a fair return on the reasonable and prudent capital invested in its assets.

TOMMY J. SLATER

Mr. Slater filed rebuttal testimony to AG witness Farrar and OIEC witness Mark Garrett.

Both witnesses proposed removal of PSO's adjustment to normalize test year levels of generation O&M expense.

According to Mr. Slater no single year is "normal." In addition to major planned maintenance being cyclical, there is planned activity that occurs over time and unplanned activity that can occur at any time. All of these types of activities affect O&M expense differently year to year. Based on the Company's extensive operating experience, he believed the three-year average captures more of the cyclical and unplanned maintenance activities than any single test year can. Mr. Garrett alludes to things that might have impacted O&M but provides no evidence of any abnormal activity that contradicts the Company's long-standing assertion that generation O&M fluctuates year to year and that a three-year average fairly approximates an ongoing level of expenses for operating and maintaining PSO's generating fleet. Non-recurring activity that did impact O&M is accounted for by removing Northeastern Unit 4 O&M before averaging.

Mr. Slater testified that Mr. Farrar asserts that the adjusted O&M expenses for 2014-2016 indicate a trend of declining O&M expense, rather than a fluctuation. According to Mr. Slater, the decline from 2014 through 2016 in adjusted Generation O&M expenses reflects the progressive elimination of preventive maintenance on Northeastern Unit 4 leading up to its retirement in 2016. This means that progressively less O&M money was spent on the unit each year which is why the total O&M expense in those years did decline. However, that decline ended with the retirement of Northeastern Unit 4 in 2016 and will not continue to decline going forward. So while the three-year period 2014-2016 O&M levels decreased due to a reduction in maintenance on Northeastern Unit 4, they still include the regular fluctuations in maintenance for the other PSO units.

Mr. Slater further testified that major maintenance that impacts expenses includes recurrent scheduled activities, generally foreseen one-time or infrequent occurrences, and unforeseen events. A turbine overhaul, a significant O&M expense when it occurs, is scheduled on approximately a 10-year cycle. Depending on the number of units undergoing a turbine overhaul in a given year O&M expense can vary greatly from a year – such as the test year – in which there were no turbine overhauls. Finally, aging plants can require maintenance that spikes an annual expense. Mr. Slater testified that PUD witness David Melvin summed it up best in his responsive testimony: "PUD agrees that Generation O&M activities are not consistent from year to year and older equipment will have increased expenditures for maintenance in future years." (Responsive Testimony of David Melvin at p. 13, line 16).

Mr. Slater did not agree with Mr. Garrett's characterization of the proposed adjustment for maintenance of the environmental controls.

The $300,000 is a new ongoing expense due to the addition of the environmental controls that went in service in 2016, not an increasing existing cost as Mr. Garrett claims. The amount was determined by the Plant Managers after assessing the operation and staffing needs that the new equipment will require. The controls installed at Comanche replaced older similar equipment and thus present no new ongoing maintenance costs. The Dry Sorbent Injection (DSI) and the Activated Carbon Injection (ACI) with fabric filter are new systems installed at Northeastern Unit 3 with new maintenance requirements for their efficient ongoing operation.

Mr. Slater testified that Mr. Garrett was not correct because the reduction proposed in O&M expense for the retirement of Northeastern Unit 4 is not a percentage reduction but rather a removal of non-recurring actual expenses from the test year. Of the $78,871,294 actual test year Generation O&M expense, $293,664 were related to NE4 during the first quarter of the test year before it was retired, and thus should be removed from the test year O&M going forward. Further, the Company is not intending to imply that the $293,000 represents the total reduction in O&M due to the retirement of Northeastern Unit 4. Maintenance on the unit was progressively reduced over a period of several years prior to its retirement.

Mr. Slater testified that Mr. Garrett's comparison of the test year O&M to the historical combined O&M of Northeastern Units 3 and 4 was flawed.

Mr. Garrett does not reference the source of the unit-specific cost data or the Northeastern Unit 3 estimated percentages presented in his Table 3 and Exhibit MG-3. Mr. Garrett's recommended adjustment relies on this unit-specific cost data which was neither provided in Mr. Slater's direct testimony or responses to data requests, nor referenced in his responsive testimony. According to Mr. Slater, Mr. Garrett assigns arbitrary allocations intended to represent expenses for Northeastern Unit 3 that vary for each FERC account. These arbitrary allocations are wrong and result in calculations that do not provide an accurate comparison of O&M costs related to Northeastern Units 3 & 4. Mr. Garrett uses the average of 2013-2015 costs to represent the "average historical level of expense." (Mark E. Garrett at p. 57, line 12) This is misleading because the years 2013-2015 do not represent historical levels of O&M for Northeaster Units 3 & 4 but rather years of declining O&M. A more appropriate comparison would be to compare the test year O&M to expenses in 2012 (as taken from the FERC Form 1 report), which was the year before the O&M reductions began for Unit 4. This comparison of Northeastern Units 3&4 production expenses was provided in the Company's response to data request OIEC 14-13 (Exhibit TJS-R-1):

"...25.8 million in 2012 and 22.6 million in 2016. This represents a $4.2 million reduction."

Mr. Slater further testified that as further explained in the response to OIEC 14-13, the cost reductions related to Unit 4 are greater than $4.2 million when staff reductions from Unit 4 are considered. However, because many of those staff were reassigned to manage the new environmental controls at Unit 3, the net impact to O&M due to staffing has been minimal.

JOHN D. QUACKENBUSH

John D. Quackenbush submitted rebuttal testimony on behalf of PSO.

Mr. Quackenbush has 35 years of experience working in the field of utility regulation. His career includes: more than four years supporting state utility regulators as a finance staff member of the Illinois Commerce Commission; 14 years performing regulatory and treasury functions in the telecommunications industry for Sprint Corporation, partially during the application of utility cost of service regulation to incumbent local exchange carriers and partially during the transition from cost of service regulation to price cap regulation; 11 years in the investment community covering approximately 80 North American companies including regulated utilities, building U.S. and Canadian domestic portfolios, and leading the global utilities team in building global utility portfolios for UBS Global Asset Management (UBS); more than four years regulating utilities as a state utility regulatory commissioner as Chairman of the Michigan Public Service Commission; and most recently, for the last year, providing consulting services to participants in regulated utility industries.

Mr. Quackenbush testified that fairness and sound regulatory policy requires a balancing of investor and customer interests. This balancing requires careful consideration of the effect of rates on customers and on legitimate investor expectations of a return on prudent investments. These two witnesses summarily dismiss the beneficial service customers received from NE4 for 36 years in recommending that investors be deprived of the return on the prudent investment that they made in this unit that provided so many years of reliable service. The recommendations of these two witnesses do not reflect a proper striking of a reasonable balance between these interests. Case law, and my experience, teaches that fairness and justice is not achieved by rigid application of mechanical principles, but instead by a reasoned review of the facts and circumstances judged by the fairness of the end result. The review should consider established regulatory principles, but not to the exclusion of consideration of the impact not just on customers but necessarily on the financial impact to the company. Both of these witnesses give no consideration to investors, and this does not serve this Commission or utility customers in the long run, nor does it equate to sound regulatory policy. Additionally, prudent regulatory policy takes into consideration whether the regulatory signals sent by certain actions promote desired utility behaviors or instead provide perverse incentives contrary to customers' and the broader public interest.

In response to Witness Bohrmann's statement that his proposed disallowance is "economic reality as it currently exists" and therefore will not send a perverse signal regarding investment decisisions (at p. 16), Mr. Quackenbush testified that he did not agree.

As Company Witness Fate explains, the "economic reality" that Mr. Bohrmann describes is not reality at all; and to dismiss the potential implications of this Commission issuing an order resulting in a write off of an asset such as NE4 shows a lack of understanding on Mr. Bohrmann's part. Investors generally strive to be aware of downside risk of their investments as a matter of course. Mr. Bohrmann appears to believe that if investors know about the worst case outcome, then the right thing for the Commission to do is to give the worst outcome to investors. He casually dismisses any hint of fairness from his recommendation.

Different Commissions and different utilities confront the challenges they face in a myriad of ways, but as a former commissioner, ultimately my decisions rested on the circumstances and the facts on the record in front of me, and the regulatory policy and signals I wanted to send to the utilities I regulated. My observation is that utilities generally are extraordinarily good at following regulatory incentives as well as disincentives. The adoption of Mr. Bohrmann's recommendation would send a perverse signal to both investors and the utility according to Mr. Quackenbush.

To comply with environmental requirements, the Company had a variety of options. Selecting the increased investment option would have allowed the Company to avoid the immediate situation where Mr. Bohrmann recommends a perverse outcome and to instead significantly increase PSO's earnings on rate base and long run costs to customers. Disallowing recovery of NE4 will essentially punish PSO for pursuing an option that was more beneficial to its customers than to its shareholders. To ignore the signal that this sends regarding future investment decisions is to ignore reality. The reality is that utilities in evaluating future resource decisions may be forced to forgo the best options for customers to avoid a potential cost disallowance of the undepreciated remaining book value of an asset, and instead spend capital to extend the life of the asset(s) as long as possible – regardless of the cost and risk to customers.

Mr. Quackenbush testified that while serving on the Michigan Public Commission he dealt with a similar situation. In 2014, my colleagues and I issued an order approving a settlement that allowed Indiana Michigan Power Company (I&M) to recover the remaining book value of its Tanners Creek coal plant (Case No. U-17524). Due to environmental regulations, I&M was faced with making significant investments to prolong their lives or to refuel with a fuel other than coal, or to close the units. Ultimately, I&M chose to retire Tanners Creek by June 1, 2015, which was prior to the end of its then depreciable service life.

The settlement agreed to by all parties, including a group representing industrial intervenors, allowed for recovery of prudent investment included in rate base by extending the period over which costs would be recovered.

Even through a settlement, Mr. Quackenbush testified that he Commission still had to determine whether or not the settlement was in the public interest and whether or not it struck the appropriate balance between customer and shareholder interests.

THOMAS J. MEEHAN

Mr. Thomas J. Meehan, filed rebuttal testimony in support of PSO.

Mr. Meehan testified that his initial overall observation was that none of the witnesses [Weber, Dunkel and D. Garrett] present any independent studies or alternative sources of the costs that are expected to be incurred to dismantle and remove PSO's generating facilities upon their retirement. Each witness simply criticizes certain aspects of the demolition studies, without offering alternative engineering studies or sources of cost covering the complete costs of demolition of each of PSO's generating units based on consideration of the specific attributes of each facility.

According to Mr. Meehan, the S&L Conceptual Demolition Cost Estimate Report that he sponsored in his Direct Testimony is an actual analysis of the costs that are expected to be incurred to dismantle and remove each PSO generating plant after its retirement. The studies were conducted using the extensive power engineering and generation facility experience of S&L and represent a reasonable, appropriate, and reliable projection of the costs of dismantling and removing PSO's generating facilities upon their retirement.

Mr. Meehan further testified that the S&L demolition cost estimates are based on the assumption that the facility will be completely dismantled with the most efficient methods that open up the basement areas of these facilities and deposit demolition rubble in these areas.

Due to the inherent differences between each unique generating facility, each plant was evaluated on an individual basis to ensure that prudent and reasonable cost estimates were provided for the most-likely demolition scenario. Site-specific walk-downs with PSO staff and drawing reviews were performed to clearly define the scope of demolition, excavation, and disposal necessary for each individual site. S&L used discussions with site staff, documents, and the dimensional information from drawings to calculate the extent of excavation and disposal required.

Contrary to Mr. Garrett's assertion, the S&L demolition cost estimate studies are based on likely decommissioning contracting approaches as well as realistic demolition techniques for the dismantlement and scrapping of PSO facilities.

In response to PUD Witness Weber, Mr. Meehan testified that the "changes in methodology" that Ms. Weber references throughout her Responsive Testimony are what he considered changes to inputs, such as the third-party sources relied upon for regional labor rates, that contribute to differences between cost estimates, but certainly are not a change in the overall methodology or approach to the demolition cost estimates. Most often, these input changes are implemented to improve cost estimating and to create a more robust and accurate estimate.

The PAS (utilized in prior demolition cost estimates) and RS Means (utilized in the 2017-cost estimate) are both valid and acceptable industry publications and sources for labor wage rates. RS Means is available earlier in a given year, allowing the wage rates included in the demolition cost studies to be more representative and commensurate to the timing of the estimates.

Mr. Meehan further testified that the Public Utility Commission of Texas (PUCT) found S&L's estimates reasonable for Southwestern Electric Power Company (SWEPCO) in its Final Order dated October 10, 2013 in Docket No. 40443, found in its Finding of Fact Number 193 that:

> *"The plant demolition studies SWEPCO used to develop terminal removal cost salvage for each of SWEPCO's generating facilities are reasonable. These studies were prepared by an experienced consulting engineering firm and incorporate reasonable methodology, data, assumptions, and engineering judgment."*

Contrary to PUD Witness Weber, Mr. Meehan testified that contractor G&A and profits are a legitimate line item to be included in a cost estimate. These are expenses that would be incurred in the overall cost on any contract project.

Mr. Meehan disagreed with Ms. Weber's allegations that S&L did not provide adequate information. Several pieces of documentation requested by Ms. Weber are either subject to contractual restrictions on dissemination by S&L or involved proprietary S&L procedures. Nonetheless, to make such information available for Ms. Weber, PSO purchased copies of the RS Means and PAS books, and S&L provided a sample calculation of proprietary methods for crew rates included in the study. This information was made available for Ms. Weber at PSO's Oklahoma City Office almost two weeks prior to the filing of responsive testimony. As such, Ms. Weber's allegation that there was a lack of documentation or information provided is unfounded. Further, S&L provided assumptions and specific details in the body of the demolition cost estimates in Exhibit TJM-3 of Mr. Meehan's Direct Testimony at a level of detail sufficient for review by experienced and knowledgeable power plant engineers.

Mr. Meehan further testified that contrary to Ms. Weber's allegation, the environmental upgrades for Northeastern Unit 3 had been already included in the 2015 demolition cost estimate. This fact was referenced in the 2017 cost estimate. Ms. Weber's concern regarding the Northeastern Unit 3 upgrades and scrap metal tonnage is moot, as one would expect the scrap metal tonnage in the 2015 and 2017 cost estimates to be similar since the upgrades were included in both estimates.

Contrary to Mr. Dunkel's testimony, Mr. Meehan testified that it is not uncommon for engineering companies such as S&L not to provide demolition services.

Mr. Meehan did not agree with OIEC, PUD, and the OAG that it would be proper to exclude an allowance for contingency from the power plant demolition studies. All three witnesses use the arguments I rebutted earlier to state that the demolition cost estimates are "likely high" to validate the removal of legitimate contingency factors. Cost estimates for virtually all contract work in all industries across the country typically include some level of contingency. It would be unreasonable and unrealistic to exclude contingency as it is an industry standard.

Mr. Meehan testified that both Ms. Weber and Mr. Dunkel recommended adjustments by using monthly averages with different periods for scrap prices from American Recycler, the source relied on in S&L's prior demolition cost estimates. Ms. Weber and Mr. Dunkel then removed 10% for separating and transport of materials.

According to Mr. Meehan, Ms. Weber and Mr. Dunkel are essentially recommending that scrap values are calculated using a method that is less accurate than the one used by S&L in the 2017 estimates.

It was determined that utilizing localized pricing closer to PSO's generating stations that was inclusive of handling and transport would be the most accurate method to determine cost at the point in time. Prior to the 2017 cost estimate, S&L utilized the regional, multi-state price from American Recycler and subtracted 10% from the price to account for the handling and transport. S&L contends that it is reasonable and more accurate to obtain a price inclusive of these elements closer to PSO's facilities.

Contrary to Mr. D. Garrett's concern, the assumption that all assets removed at the time of demolition are scrap value only, and not subject to resale, is appropriate considering the typical approach for the life cycle operation of a power plant facility. As a power plant ages, it will require an increasing amount of O&M expense to maintain the plant in a safe and reliable manner. As the economics of operating the generator degrade, the operator will often be required to find opportunities to save in some areas while attempting to maximize the economics of the generating plant. By the time the plant is uneconomic and reaches the end of its useful life, the general condition of the plant has often degraded to a point where there is little usable equipment. As such, end of life plant equipment has very little resale value other than scrap because it is very rarely in acceptable condition, does not have warranty or performance guarantees that new equipment would have, and is typically inefficient and obsolete relative to other equipment available in the market. Mr. Garrett also ignores the costs with proper removal, transport, installation, reconnection, and commissioning of used equipment that decreases any potential embedded value.

In response to Ms. Weber and Mr. Dunkel, Mr. Meehan testified that it was his understanding that the scope of the Breed demolition conducted to date by AEP only constituted a portion of the full scope of demolition that is detailed in the 2005 S&L cost estimate for the Breed facility. Considering that the full scope of demolition costs detailed in the S&L study are necessary to remove all of the components associated with the plant's prior operations and to restore the site, to the extent practical, to its original condition and that only a partial demolition was completed, confirms the validity of the S&L's approach, and not the point of Ms. Weber and Mr. Dunkel that S&L's approach are overestimated.

According to Mr. Meehan, Mr. Dunkel made similar arguments and comparisons to I&M's Breed Plant as he does in this proceeding. The IURC stated the following in its Order dated February 13, 2012:

> *"We find that it is not appropriate to use the actual cost data from the Breed Plant demolition to estimate costs for demolition of distinct facilities with unique configurations. Accordingly, we further find that Mr. Dunkel's proposal to adjust the Tanners Creek and Rockport demolition cost estimates based on cost data for the Breed Plant demolition must be rejected."*

Although Mr. Dunkel makes no specific adjustment to PSO's demolition cost estimates in consideration of Breed, he does attempt to characterize the PSO's demolition cost estimates as excessively high, as does Ms. Weber, a point that the IURC rejected.

> *"The evidence of record shows that S&L is well-qualified with specific expertise introducing demolition cost estimate studies and that the S&L demolition cost estimates are clearly substantiated and based on site specific data, assumptions consistent with prudent industry practices and previous S&L demolition estimates. This Commission has long accepted and relied on site specific S&L demolition cost studies for purposes of establishing depreciation rates."*

STEVEN F. BAKER

In Rebuttal testimony to AG Witness Alexander, Mr. Baker testified that while PSO has invested in system hardening and resiliency programs for its distribution system, Mr. Alexander mischaracterizes the amount of that investment. Mr. Alexander states that "PSO has made significant infrastructure upgrades in its distribution ($205 million)..." system. (at 6) However, of the $205 million in distribution investments, only $24.8 million of this amount was for system hardening and resiliency programs. Much of the distribution investment since the last rate case has been for routine items, such as street/highway locations, third party requests, distribution line meter and transformer purchases, new service to customers, and service restoration. Although these investments are extremely important in maintaining PSO's distribution system, they do not harden the system or improve resiliency, and would therefore not help minimize storm damage.

Mr. Baker further testified that in terms of the system hardening and resiliency programs, PSO was only approved to expand its Reliability Vegetation/Underground (RVU) Rider to include system hardening and resiliency programs on December 18, 2013, in Cause No. PUD 201300202. The RVU Rider, which became the System Reliability Rider (SRR), helped PSO to invest the aforementioned $24.8 million in system hardening and resiliency programs over the past couple of years. However, the SRR was terminated effective as of the end of 2016 per the final order in Cause No. PUD 201500208. While the vegetation management portion of the rider was moved to bases rates, there was no similar provision for the hardening and resiliency funding.

Also as part of this assertion, Mr. Alexander states that AMI helps lower costs associated with damage restoration. In this assertion Mr. Alexander is correct, as I describe the benefits of AMI during storms in my direct testimony. However, the amount of storm cost that AMI will be able to reduce will vary from storm to storm. Mr. Baker further testified that as he had stated in direct testimony, even with AMI in place, the July 2016 windstorm still cost approximately $4.9 million. Even fully utilizing AMI's capabilities, this one storm was nearly $2.0 million more than what PSO currently has in base rates for storm expenses.

Additionally, Mr. Alexander argues that PSO's vegetation management program "...decreases damage to the system and lowers costs in the long run." (at 6-7) Mr. Alexander is correct to a certain extent, as PSO's vegetation management program has helped to limit storm damage. However, Mr. Alexander fails to take into consideration that PSO's current cycle-based vegetation management program has been in place since 2005, with PSO's first four-year cycle being completed in 2010. Although PSO's vegetation management program has significantly benefitted the system, PSO still experienced average storm costs of approximately $10.7 million per year for the period of 2010 through 2016 while the current vegetation management program was in place. Stated another way, PSO's vegetation management program has already achieved significant benefits and will continue to help maintain PSO's reliability, but it will do little to improve storm cost reduction beyond what has already been realized.

According to Mr. Baker now is the appropriate time to update PSO's storm damage expenses to reflect a more current average. As Vice President of Distribution Operations for PSO Mr. Baker testified it was his responsibility to ensure the reliability of PSO's distribution system for the benefit of PSO's customers. As part of that responsibility, both Company witness Hamlett and I have established the need to update storm expenses by showing the historical cost of storms PSO has experienced, describing the severity of these storms in detail, as well as PSO's processes, programs, and efforts to minimize these costs.

Mr. Baker supported the conclusions of Mr. Spanos that wood pole failures increased with age. According to Mr. Baker, over the course of his 27 plus year career in distribution operations, he has consistently observed that wood pole failure rates increase with age. Wood poles have a finite life and are constantly under attack by natural forces such as wind, ice, rain, excessive temperatures, lightning, bacteria and exposure to sunlight. As a result, wood poles are always in some state of decay and deterioration.

PSO's current ground line inspection programs support the fact that failure rates increase as wood poles age. A sample of recent ground-line inspection results indicates the wood pole failure rate increases steadily with each 10 year band from year 11 through year 60 in service. This sample shows that 50+ and 60+ year old poles fail at nearly twice the rate as 40 year old poles. This information matched Mr. Baker's observations and cumulative experience regarding wood pole performance and failure rates.

PAULINE M. AHERN

In response to Witness M. Garrett's "thought" that the OCC should not give Ms. Ahern's testimony any weight, Ms. Ahern testified that had she testified in approximately 275 rate cases over the last 30 years, before more than 30 regulatory commissions on various topics, not limited to rate of return, e.g. capital structure issues, relative investment risk issues, and credit quality issues, all of which does indeed qualify me as a ratemaking expert. In addition, as my direct testimony discusses, the revenue requirement set in any rate proceeding, including this one, is a combined function of O&M expenses, depreciation, income taxes, rate base and the capital (debt and equity) financing that rate base. Therefore, the level of each one of these components is critical to and interrelated with the development of fair and reasonable rates, including the fair rate of return and she is therefore imminently qualified to comment on the effect of regulatory policy on the cost of capital, including the investor required return on common equity.

According to Ms. Ahern, Witness D. Garrett misstates the types of risk that are relevant to an evaluation of a regulated entity's return on equity in a regulatory proceeding. Regulation is intended to serve as a substitute for competition where the regulator's obligation is to establish rates that provide the regulated entity with an opportunity to earn a fair rate of return defined as a return commensurate with the returns on investments of commensurate risk. To not consider company specific risks in arriving at a recommended or allowed return on common equity in a base rate proceeding violates the stand-alone principles of finance and ratemaking. It does so because it is the use of invested funds, not the source of those funds which gives rise to the risk of the investment. Also, because the rate of return to be set in this proceeding will be applied to PSO's rate base and PSO's alone, it is the total risk, the sum of all business and financial risks, of PSO's operations/rate base which are relevant establishing an allowed return on common equity in this proceeding.

Ms. Ahern testified that the financial literature supports the basic financial principle that it is the use of the funds invested which gives rise to the risk of the investment, not the source of those funds.

In other words, it is the "risks and uncertainties" surrounding the property employed for the "convenience of the public" which determines the appropriate level of rates. In this proceeding, the property employed "for the convenience of the public" is the rate base of PSO. Therefore, it is the total investment risk of PSO, and its rate base alone, which is relevant to the appropriate rate of return for the Company. Curiously, Witness D. Garrett implicitly agrees when he states that "[a]warded returns are set through the regulatory process and may be influenced by a number of factors other than objective market drivers. . . the cost of capital is driven by stock prices, dividend, growth rates, and most importantly – it is driven by risk."

In view of the foregoing, it is entirely appropriate and required that all the risks faced by PSO, including the risk of cost recovery disallowances, regulatory environment, and the like, be considered when setting PSO's allowed rate of return, including common equity cost rate.

According to Ms. Ahern, in Witness D. Garrett's discussion of systematic versus non-systematic risk in his Responsive Testimony he has confused the theory behind the Capital Asset Pricing Model ("CAPM") with the reality.

Witness D. Garrett's assumption that all investors hold well/fully diversified portfolios in which all non-systematic risk is diversified "away" is not realistic. The market is full of investors who hold less the fully diversified portfolios, e.g., money market fund investors. As noted by Morin, the CAPM "assumes that investors hold diversified portfolio and operate in capital markets unencumbered by transaction costs, taxes, and restrictions on borrowing and short-selling."

In addition, the assumption of investors holding diversified portfolios is inconsistent with the stand-alone principle of finance and regulation. It is the risk of investment in PSO's assets/rate base which gives rise to PSO's investment risk and hence its cost of common equity. Moreover, its shareholder, American Electric Power Company, Inc. ("AEP" or "the parent"), while holding a portfolio of assets, i.e., operating subsidiaries, is not fully diversified as most of these subsidiaries are regulated operating subsidiaries.

According to Ms. Ahern, the second issue concerns beta as a measure of the volatility of stock market returns, because beta is an incomplete measure of risk.

Ms. Ahern testified that Witness D. Garrett's assertion that the only relevant risk to estimating/allowing a return on common equity for PSO is market risk, as measured by beta, should be rejected by the OCC.

Ms. Ahern addressed Witness D. Garrett's financial risk discussion and his Figure 6 which purports to demonstrate the "Effect of Increasing Debt Ratio on Weighted Average Cost of Capital." According to Ms. Ahern, the example violates the financial theory of the relationship between leverage and financial risk formalized by Modigliani and Miller which holds the Weighted Average Cost of Capital ("WACC") constant, not the cost of common equity. Figure 6 also violates the basic financial principle of risk and return, i.e., investors require a greater return for bearing greater risk. As discussed previously, the greater the leverage in a company's capital structure, the higher the financial risk of the company which must be factored into the common equity cost rate. Hence, the assumption of a constant common equity cost rate, e.g., 9.0%, across all possible levels of debt in a capital structure, violates basic financial theory. Witness D. Garrett's conclusions should thus be disregarded by the OCC.

In response to Witness D. Garrett Figure 1: Awarded Returns on Equity vs. Market Cost of Equity (2005 – 2016), Ms. Ahern testified that the returns on the market (Market Cost of Equity) shown in Figure 1 are relative to market price during an unprecedented period of low interest rates orchestrated by the Federal Reserve's Federal Open Market Committee while the regulatory awarded returns are to be applied to book value. Because the cost of equity is a long-term concept, Witness D. Garrett's use of the 2005 – 2016 low interest rate time period is not representative of the long-term cost of equity, for either the market or for individual firms. Recreating the Market Cost of Equity over the entire 1961 – 2016 time period provided by OIEC, et al. Witness D. Garrett results in an average 10.27% Market Cost of Equity which still understate the true Market Cost of Equity because actual market returns over that period were 11.39%. Thus, any comparison between the market costs of equity over such a short time horizon, characterized by artificially low interest rates, and the awarded returns on equity shown in Figure 1 is an "apples and oranges" exercise and, therefore, meaningless.

In response to Witness D. Garrett's claim that it is not reasonable to look at the projected returns on book equity of non-regulated firms Ms. Ahern testified that Hope and Bluefield do not specify that the "firms of comparable risk" or the firms having "corresponding risks" be regulated utilities. Hence, it is reasonable to evaluate the projected returns on book common equity, as well as the expected market returns, of non-priced regulated firms of similar total risk, since utilities, such as PSO, compete with all other firms in the capital markets, regulated and non-regulated alike.

Moreover, by focusing only on beta, Witness D. Garrett has ignored the fact that the Non-Regulated Sample was selected based upon combined measures of total risk, i.e., betas as a measure of systematic risk and the standard errors of the regression giving rise to those betas.

According to Ms. Ahern, Witness Parcell's sole concern with Ms. Ahern's testimony is that the projected returns for the Non-Regulated Sample exceed the actual returns for the S&P 500 without providing any analysis of the risk of the Non-Regulated Sample relative to that of the S&P 500. Ms. Ahern testified that what Witness Parcell has ignored in his "disagreement" is the fact that the Non-Regulated Sample was selected upon mutually exclusive bases of a range of unadjusted betas for PSO Witness Vilbert's Electric Sample and standard errors of the regressions giving rise to those betas. Thus, his "disagreement" is misplaced.

The cost of capital, including the common equity cost rate, is a function of investor perceived risk. The Non-Price Regulated Sample was based upon selection criteria encompassing total investment risk, i.e., beta as a measure of systematic risk (i.e., market or non-diversifiable risk) and the standard error of the regression as a measure of unsystematic risk (i.e., company-specific risk). Companies which have similar betas and standard errors of regression have similar total investment risk, therefore, the Non-Regulated Group is similar in risk to PSO Witness Vilbert's Electric Sample and, hence, similar in risk to PSO.

Ms. Ahern addressed Witness Farrar's suggestions that the OCC require "that debt financing be used for large projects to reduce the capital costs" claiming that it would save ratepayers over the life of any debt issued, specifically $12.9 million at a 4.5% cost rate on the $223 million in Environmental Compliance Plan ("ECP") assets. Mathematically, this may be true, however, in his savings estimate AG Witness Farrar has ignored financial theory of risk and return. The greater the leverage in a company's capital structure, the greater the financial risk which increases common equity risk as well. Should PSO's credit quality and credit/bond rating be negatively affected by the pressure on cash flows due to the increase in leverage caused by financing large assets with debt alone, PSO's debt cost rate is likely to rise as well. His suggestion is, thus, not likely to save ratepayers anything, as both PSO's debt and common equity costs would increase.

In responding to Witness Farrar's suggestion that the OCC "delay the recovery of depreciation expense on PSO's Environmental Compliance Plan assets for a few years", Ms. Ahern testified that this is nothing more than "kicking the can down the road," pushing the annual $9.6 million depreciation expense to a future generation of ratepayers. In fact, those ratepayers would be paying more, as the delayed depreciation expense would be added to the annual depreciation expense over the asset's remaining life.

Ms. Ahern rebutted Witness Bohmann's proposed regulatory treatment of Northeastern Unit 4. According to Ms. Ahern, Witness Bohrmann supports his recommended regulatory treatment of Northeastern Unit 4 by citing an article which noted that "the U.S. electric utility industry's earnings before interest, taxes, depreciation, and amortization ('EBITDA') rose 16 percent on flat generation growth from 2012 to 2016, but has reportedly reduced the value of its assets by $55 billion during this period." However, Witness Bohrmann has not provided any support that this statement is applicable to PSO. Nor has Witness Bohrmann refuted what the financial community has been told concerning the regulatory treatment of Northeastern Unit 4. He has merely recounted it. Since there is no evidence contrary to the fact that "the Company's future net income and cash flow could be reduced and could impact the Company's financial condition," there is no basis for his proposal to spread the loss in value of the Northeastern Unit 4 between ratepayers and shareholders.

Relative to Witness Bohrmann's statement that his "proposal sends the appropriate signal to PSO and other regulated utilities in Oklahoma that utility management should always seek out creative solutions to maximize value for its ratepayers, in reality utility management should always seek out creative solutions to enable the utility to continue to provide safe and reliable service to its customers.

JOHN J. SPANOS

Mr. Spanos' rebuttal testimony presents a general discussion of depreciation principles and the depreciation study process. He discussed the objective of depreciation in allocating the full costs of the Company's assets (original cost less net salvage) over their service lives, explain the concept of intergeneration equity, and responds to incorrect concepts set forth in the testimonies of other parties. He then discusses the process and judgments involved in estimating service lives and net salvage. Mr. Spanos explains in detail, the depreciation study he performeded is consistent with accepted practices in the industry and established depreciation concepts.

In contrast, the other parties' proposals are inconsistent with accepted depreciation practices and lack the application of informed judgment. The other parties' (particularly OIEC and the AG) proposals for mass property service lives do not interpret the historical data in an appropriate manner and do not apply informed judgment in estimating service lives. As a result, the other parties estimates of service lives for the Company's assets are unreasonably long for the types of property studied. The AG's net salvage recommendations are not based on a widely-accepted method, and instead are based on the flawed premise that a utility should only accrue net salvage at a level that is similar to what it has spent in recent years. The result is that the AG's net salvage method results in net salvage estimates that will accrue far less than the full cost of the Company's assets for many accounts.

After a general discussion of depreciation principles, Mr. Spanos addressed in more detail the specific adjustments to the depreciation study that each witness proposes. These include:

- <u>Mass property service lives</u>. The currently approved depreciation rates are based on unreasonable and unrealistically long service life estimates. The recommendations in Mr. Spanos' depreciation study are much more reasonable for the Company's assets. PUD, OIEC and AG have recommended different service life estimates from mine for certain mass property accounts. The process of estimating service lives for mass property (e.g. transmission and distribution plant accounts) incorporates the results of statistical life analysis, but also must incorporate informed judgment. Authoritative depreciation sources are clear that judgment must be employed so that the resulting service lives are reflective of the property being studied and the future conditions in which it will operate.

OIEC and AG have proposed changes to the largest number of accounts. In each circumstance, both OIEC and AG have based their suggestions solely on mathematical curve matching without the application of judgment. The result is that Mr. Garrett's and Mr. Dunkel's estimates are unreasonable and unrealistic for the property studied. The inappropriateness of their mathematical approach is perhaps best seen in the wide variance between service lives Mr. Garrett recommended in the instant case and what he proposed in Cause No. PUD 201500208. Mr. Garrett's average service life estimates in the instant case are, for some accounts, less than half what he proposed only two years ago. A sound approach to estimating service lives would not produce such extreme changes in estimates in such a short period of time between studies.

PUD has also made changes to a few mass property accounts, which, while not as extreme as some of OIEC and the AG's estimates, also do not incorporate the requisite judgment which produces unreasonable service life estimates.

- <u>Mass property net salvage</u>. The AG proposes the most significant changes to net salvage estimates, as the AG has proposed to use an unorthodox and inappropriate methodology for determining net salvage estimates. The AG's proposal to depart from the longstanding and widely accepted net salvage method has no reasonable mathematical basis, no support in authoritative depreciation textbooks, and is not widely used in the industry. PUD and OIEC have used traditional and accepted methods for net salvage. PUD has recommended two changes to the Company's net salvage estimates for mass property accounts, and OIEC proposes no changes to my estimates.

- <u>Terminal net salvage for production plant accounts</u>. In order to recover the full cost (original cost less net salvage) of the Company's assets, net salvage estimates must be stated at the cost at which they will be incurred. Therefore, it is appropriate to escalate the estimated terminal net salvage costs for the Company's power plants to the year of the expected retirement of each facility. The approach recommended in the depreciation study of escalating these costs is consistent with depreciation principles and is accepted and supported by a large majority of jurisdictions and authoritative depreciation texts. I will not address the decommissioning study in detail, as that will be addressed in Mr. Meehan's rebuttal testimony.

- <u>Amortization periods</u>. There are additional proposals from the parties, which include a change in the life for software and changes to general plant amortization accounts. I also explain why the other parties' proposals for these issues are inappropriate.

According to Mr. Spanos, Mr. Garrett, on behalf of OIEC has submitted two proposals. In the first, OIEC proposes to continue using the current depreciation rates. In the second, OIEC proposes to use the results of Mr. Garrett's latest depreciation analyses. In my direct testimony, I explained that the current depreciation rates are based on very unrealistic estimates for many accounts, and are not appropriate. Mr. Garrett's proposals in the instant case actually support my view that the current estimates are inappropriate. Interestingly, many of the currently approved depreciation rates are based on service life estimates previously proposed by Mr. Garrett in Cause No. PUD 201500208. However, in this case, for these very same accounts, Mr. Garrett now proposes service lives that are, in many cases, considerably shorter than what he had proposed only two years ago. For example, in Cause No. PUD 201500208, Mr. Garrett proposed a 98-year average service life for Account 373, Street Lighting and Signal Systems. In the instant case, he has proposed a 44-year average service life for this account. That is, his life estimate in the instant case is less than half of what he proposed only two years ago. This confirms that the current depreciation rates are based on unreasonable estimates, Mr. Garrett, who initially proposed them, no longer arrives at the same conclusion. It also further highlights the flaws in Mr. Garrett's approach. If, in the span of only two years, Mr. Garrett can estimate lives that are more than 50 years apart, it suggests there is a serious flaw in his approach to estimating service lives. Thus, both of Mr. Garrett's options should be rejected. The Company's current depreciation rates are inadequate and proposed rates based on standard statistical analyses, properly interpreted, and the application of informed judgment, not mathematical curve fitting alone, should be adopted.

Mr. Spanos further testified that when Mr. Garrett argues that "it is better that useful lives are overestimated rather than underestimated" he is incorrect.

Mr. Spanos testified that in his view, which is shared by authorities on ratemaking principles, Mr. Garrett's opinion is fundamentally wrong. First, for Mr. Garrett to even make such a claim, he must dismiss the entire concept of intergenerational equity. He states that "unintentionally overestimating depreciable lives (i.e., underestimating depreciation rates) does not harm the Company" and argues that "if an asset's life is overestimated, there are a variety of measures that regulators can use to ensure the utility is not financially harmed." Nowhere in his discussion is there even an acknowledgment that such a situation would, by definition, result in intergenerational inequity. Mr. Garrett has not even considered the concept and the result that "overestimating depreciable lives" will most certainly harm future generations of customers who will unfairly be required to pay for assets that do not provide them service.

Further, Mr. Garrett does not acknowledge that if depreciation rates are too low (for example, if lives are "overestimated") the cost to customers will, over the long term, actually be higher, all else being equal. This occurs because accumulated depreciation is an offset to rate base. If depreciation expense is too low, then accumulated depreciation will be lower than it otherwise would be, producing a rate base that is higher than it otherwise would be. Thus, if customers pay too little in depreciation expense, they will have to pay a higher return on rate base, as rate base will be higher. As a result, over the long-term, depreciation rates that are too low actually produce a higher total cost to customers. Mr. Garrett's preferred approach to minimize depreciation expense is not only harmful to customers in that it is likely to produce intergenerational inequity, but also because it will likely result in higher customer rates over the long term.

Mr. Spanos testified that one of the foremost ratemaking texts is James Bonbright's Principles of Public Utility Rates. Bonbright addresses whether it is preferable to err on the side of higher depreciation as opposed to lower depreciation. Bonbright concludes that it is preferable to overestimate depreciation expense as opposed to underestimate depreciation expense. Bonbright refers to this as a criterion of "conservatism", and states:

> This criterion suggests that, as between two proposed methods of cost amortization, one of which undertakes faster write-offs than the other during the early years of useful service lives, any reasonable doubt may well be resolved in favor of the former unless, on consequence, the resulting temporarily higher rate levels will be a serious deterrent to the development of a demand for utility services commensurate with plant capacity.

Thus, Bonbright supports the exact opposite conclusion of Mr. Garrett's opinion on this matter.

Mr. Spanos testified that both OIEC and the AG recommended service lives that, for some accounts, are much too long to recover the Company's investments over their service lives. Each party has also recommended net salvage estimates that will not result in the full allocation of the Company's costs. Additionally, in Mr. Farrar's responsive testimony, the AG argues for the deferral of costs, which is a blatant disregard for the concept of equity. The fact of the matter is that PSO's depreciation rates, as established in prior cases, are too low. This is true for many of the unrealistic service life estimates used in calculating current depreciation rates. But it is also evidenced by the fact that, the Company was not afforded the opportunity to recover the costs of Northeastern Units 3 and 4 during their service lives, resulting in future customers having to pay the cost of assets from which they will receive no service. In order to limit the risk of similar problems in future depreciation studies, the other parties' recommendations must be rejected in order to ensure the equitable recovery of the Company's assets.

RESPONSIVE TESTIMONY

<u>Public Utility Division</u>

GEOFFREY M. RUSH

On June 30, 2017, PSO filed its Application for an adjustment in its rates and charges and the electric service rules, regulations, and conditions of service for electric service. The purpose of this testimony is to provide Mr. Rush's response to the five recommended revisions to the FCA Rider of PSO, which were outlined in the Rate Design Responsive Testimony of OIEC witness Scott Norwood that was filed on October 3, 2017.

Mr. Rush recommends the Commission reject Mr. Norwood's first, second, and third recommendations relating to FCA factors.

Mr. Rush recommends the Commission accept Mr. Norwood's fourth and fifth recommendations relating to FCA factors.

Mr. Rush believes Mr. Norwood's first recommendation, which would require PSO to file an application with the Commission to revise PSO's FCA Factor on an annual basis, requires revisions to 17 0.S. § 253 of the Oklahoma Statutes and OAC 165:35 and 165:50 of the Commission Rules. Adding FCA factor causes to the existing Commission case load will unnecessarily increase the workload of PUD, delay implementation of Fuel Factors, and unnecessarily burden Commission resources. Additionally, approving this recommendation would cause PSO's ratepayers to incur additional regulatory expenses.

Mr. Rush believes the Commission should reject Mr. Norwood's second and third recommendations because approval of these recommendations would result in substituting regulation for the utility's reasonable self-management, i.e., usurp the managerial discretion of the Company.

Mr. Norwood's second recommendation would eliminate the provision for interim FCA factor adjustments. In addition to Mr. Rush's belief that a utility's reasonable self-management should suffice, Mr. Rush believes PSO uses its best efforts to establish FCA factors that reduce variations in the balance in the over/under recovery account. Mr. Rush believes having a process that allows the utility the flexibility to make periodic adjustments to the FCA factor could reduce the potential rate shock experienced by ratepayers during large true-up events.

Mr. Norwood's third recommendation would modify the DEF$ term of the FCA formula to shorten the period during which accumulated fuel over-recovery balances are refunded to customers from 12 months to 1 month. In addition to Mr. Rush's belief that a utility's reasonable self-management should suffice, Mr. Rush believes that PSO's current refund policy is sufficient, which is to credit over-recoveries to customer classes using the same allocation method by which the FCA factor collected the revenue.

Mr. Rush does not object to Mr. Norwood's fourth recommendation, which would require PSO to provide to each party in the Company's most recent base rate or FCA revision proceeding electronic copies of monthly reports submitted to PUD. However, Mr. Rush notes the public, including the parties to the base rate case, already have the ability to request and obtain such reports.

Mr. Rush does not object to Mr. Norwood's fifth recommendation that would modify the term of the FCA formula to exclude explicitly net revenues earned from SPP energy sales from the margin sharing provision that currently applies to off-system sales. Mr. Rush believes that there are various operational complexities that create risk for a Market Participant that could increase costs; however, the ratepayer should retain fully any off-system sales that result from the utility's participation in the Integrated Marketplace.

For the reasons stated and supported in his Testimony, Mr. Rush believes that his recommendations are fair, just, reasonable, and in the public interest.

JASON C. CHAPLIN

Jason Chaplin is employed by the Public Utility Division ("PUD') of the Oklahoma Corporation Commission ("OCC" or "Commission") as an Energy Coordinator. Mr. Chaplin filed Rebuttal Testimony on October 16, 2017. The purpose of Mr. Chaplin's Rebuttal Testimony is to present PUD's response to the Southwest Power Pool Transmission Cost ("SPPTC") tariff recommendations, which was outlined in the Responsive Rate Design Testimony of Oklahoma Industrial Energy Consumers' witness Scott Norwood on October 3, 2017. PUD witness Geoffrey M. Rush will provide Rebuttal Testimony regarding Mr. Norwood's recommendations relating to the Fuel Cost Adjustment Rider.

Mr. Chaplin makes the following recommendations regarding Mr. Norwood's proposed recommendations related to PSO"s SPPTC tariff:

- PUD does not support Mr. Norwood"s first recommendation of requiring the Company to file an application with the OCC to revise the SPPTC tariff each year because PUD believes the Company's current annual redetermination process provides for an adequate level of review;

- PUD supports Mr. Norwood's second recommendation to make explicit that the Company has an ongoing obligation to provide testimony which addresses the reasonableness of third party charges recovered through the SPPTC in future base rate proceedings;

- PUD does not support Mr. Norwood's third recommendation to eliminate the current provision for the Company to implement interim adjustments to the SPPTC tariff at any time when an over-recovery or under-recovery of expenses exceeds 10%. PUD believes the 10% over-under provision, the annual re-determination process, and reviews in future base rate proceedings provide reasonable protections to customers by allowing multiple opportunities for review, not just review in future rate proceedings; and

- PUD does not support Mr. Norwood's fourth recommendation for this Commission not to adopt the provision to require a broader review of the SPPTC filing in instances when an SPPTC revision results in an increase that exceeds 50% because this broader review provides another mechanism for PUD to ensure customer protection while also incentivizing PSO to pursue cost control within the SPP organizational structure continually.

Finally, Mr. Chaplin testified that he believes these recommendations are fair, just, reasonable, and in the public interest.

JOHN O. AARON

Mr. Aaron testified that Mr. Schwartz, Dr. Blank, and Mr. Garrett reject PSO's request to allocate its transmission cost-of-service on a twelve coincident peak (12 CP) basis and support an allocation based on a four coincident peak (4 CP) basis.

According to Mr. Aaron, while historically PSO planned and built its transmission system to serve its own retail and wholesale native load, that is no longer the case today. Now, SPP has functional control of PSO's transmission assets to meet regional and local needs; therefore, what was done historically in regard to transmission planning and constructing as a basis for determining the appropriate transmission allocation, no longer exists. In other words, the justification for using 4 CP no longer exists.

According to Mr. Aaron, cost causation is the key element with PSO's request. The transmission costs were incurred by PSO as a direct result of providing service to its retail customers based on transmission charges from SPP. There is no need to reallocate the transmission costs and inappropriately shift the costs to other classes. PSO is a member and transmission customer of SPP, the regional transmission provider that bills its transmission service customers, like PSO, on a 12 CP basis. As a result, PSO also pays for transmission to serve its load on a 12 CP basis.

According to Mr. Aaron, the 12 CP allocation of transmission costs reflects how PSO's customers use the transmission system. The customers that benefit from the use of the transmission system also bear their appropriate share of the cost for their use of the transmission system. PSO's larger customers rely more heavily on the SPP transmission system; thus, they should bear a more equitable share of those costs billed by SPP than they currently do with the existing 4CP allocation.

PSO's recommendation to use a 12 CP appropriately allocates transmission costs based on actual use of the SPP transmission system.

Mr. Aaron testified that PSO agrees to allocate all charges recorded in FERC Account 565 (Transmission of Electricity by Others) on a 12 CP allocation. This allocation is consistent with Dr. Blank's testimony (page 4) regarding expenses recorded in FERC Account 565 and the billing practices of the transmission provider, and with the testimony of Mr. Schwartz since the transmission expenses currently recovered by PSO through the SPPTC are recorded in FERC Account 565.

Mr. Aaron testified that the updated retail base rate revenues are $596,009,058 for the six-month post-test year period. This amount reflects the update to all billing determinants and removes the adjustment for Energy Efficiency and Demand Response kWh and kW originally proposed by PSO.

JENNIFER L. JACKSON

Ms. Jackson testified that PSO was providing a revised proof of revenue statement in response to Mr. Farrar's responsive testimony. According to Ms. Jackson, her rebuttal EXHIBIT JLJ-1R included the updated billing determinant information and adjusted revenues and appropriately accounted for normalized billing determinant data associated with class customer counts that existed during June 2017, as well as the removal of the EE/DR program adjustment as discussed by Mr. Aaron. The revised proof of revenue also included the calculation of the compliance pro forma adjustment for all classes based on a revised M-6 work paper, which is sponsored by Mr. Aaron.

Ms. Jackson further testified that as shown in the filed WP M-6 (the adjusted normalized test year billing determinants) and the proof of revenue statement, the elements that determine the adjusted base rate revenues are billing determinants. These billing determinants include some or all of the following depending on the rate class:

- test year end customer count;
- fixture counts;
- energy (kWh);
- demand (kW);
- kVAR units

These billing determinants are associated with and normalized for the test year-end level of customers for each rate class, and any associated minimum bill or final bill revenue. In EXHIBIT JLJ-1R, all billing determinants have been updated and normalized based on a June 2017 customer count level.

Ms. Jackson presumed that the June 2017 adjusted base rate revenues and associated billing determinants will be used to update the originally filed current total base rate revenues and will be used in setting the final rates to be approved in the compliance phase of this Cause.

Ms. Jackson testified that PSO has proposed to move its major retail rate classes to the required cost-to-serve for each class.

Mr. Schwartz stated that it is PUD's position that the Company could have improperly included revenue adjustments related to its EE/DR. He also stated that this adjustment improperly affected the proposed allocation factors.

According to Ms. Jackson, as stated in Mr. Aaron's rebuttal testimony, PSO has agreed to remove the EE/DR adjustment and to adjust the class allocation factors accordingly as long as the associated kWh and kW are recovered through the DSM Rider.

Ms. Jackson further testified that Mr. Schwartz also has an issue with moving major classes to their cost-to-serve based on the large increase requested in this Cause.

PSO's proposal to move the major rate classes to their cost-to-serve takes into account the individual rate classes included in a major rate class category. Many individual rate classes would have experienced increases significantly higher than the system average increase in order to move the rate class to an equalized return. The system average base rate increase, as proposed by PSO, is 28.33%. This results in a total revenue increase, which includes fuel and rider revenues, of 11.43%.

According to Ms. Jackson, Mr. Farrar recommended that classes move to the true cost-of-service only if the Commission adopts the Attorney General's recommended revenue requirement. If the Attorney General's recommendation is not adopted, Mr. Farrar recommends a proportional increase be applied to all customers.

Ms. Jackson did not agree with Mr. Farrar because in past cases, PSO has recommended a revenue distribution methodology similar to Mr. Farrar's approach and the Commission has ruled against that methodology. In fact, the Commission ruled against that same methodology recently in PSO's last rate case, Cause No. PUD 201500208.

Ms. Jackson testified that Mr. Schwartz stated that PUD believes that changing the transmission allocator from a 4 CP to a 12 CP fails to represent a summer-peaking utility and creates a disconnect between the cost allocation and the current rate design and sends confusing signals to customers.

Ms. Jackson responded by stating that PSO's rate design is based on seasonal signals that indicate the cost to produce electricity is higher in the peak period due to increased usage. Customers have the choice to use and conserve electricity at their discretion being aware of the price they are paying during the on-peak season; for example, customers can turn the thermostat up in the summer to conserve energy by using less kWh. However; those air-conditioning kWh are not shifted to the off-peak. PSO's rates also include time-of-day rates that encourage shifting load from an on-peak period window, such as 2 p.m. to 7 p.m., to another time to avoid higher prices. This shift still, regardless of the time of day it occurs remains within the on-peak (summer) season; load is shifted from one hour of the day to another but not into the off-peak season. Secondly, PSO's rates recover all of the functional costs from production, transmission, and distribution services. Each of these functions has different allocation methodologies, even though PSO is a summer peaking utility. Finally, it is also important to note that PSO does not use a straight 4 CP allocator for its production function, even though PSO is a summer-peaking utility. The production function is allocated to the classes on a four coincident peak average and excess (4-CP A&E) allocation methodology. While this allocation methodology accounts for the summer-peaking nature of the generation costs, it also includes components for usage outside of the summer peaks, in essence, recognizing usage in all 12 months.

According to Ms. Jackson, Mr. Garrett stated that PSO has failed to consider that changing to a 12 CP methodology will skew price signals because PSO's industrial rates include a demand ratchet that is based on the customers' peak month's use rather than customers' 12 peak month's use. Mr. Garrett believes that a change to a 12 CP allocator would penalize industrial customers who have responded to PSO's price.

Ms. Jackson testified that industrial rate classes demand charges are based on the demand occurring during the peak period of the on-peak season (four summer months). Production costs are recovered through the peak demand charge. What Mr. Garrett fails to mention is there are two demands recorded for billing under the industrial rate schedule. The tariff requires a peak demand and a monthly maximum demand. The monthly maximum demand charge is based on the highest metered kW occurring during the month. The maximum demand charge is a charge based on maximum peak usage during the entire year, all 12 months, and recovers a portion of the transmission costs. According to Ms. Jackson, this illustrated that PSO's industrial rates are not inconsistent with PSO's proposed 12 CP transmission allocation methodology.

Ms. Jackson further testified that PSO can agree to update the industrial rates according to OIEC's proposal of an across-the-board charge only to the demand charge based on the final recommendations in the Commission's Order.

STEVEN L. FATE

Mr. Fate addressed Mr. Norwood's testimony beginning on page six where Mr. Norwood describes what he terms as "deficiencies" with PSO's FCA alleging that there is a lack of "transparency" and a "systematic or transparent process for review and approval." He goes on to criticize PSO for revising fuel factors "four times at different times of year since May 2015" and states that the changes were made with "relatively little regulatory oversight." He then claims that this "variability and frequency of changes" is difficult for customers, particularly large commercial and industrial customers' budgets.

According to Mr. Fate, PSO did change the FCA rates four times since May 2015; however, Mr. Norwood provides an incomplete explanation or context for the justified changes.

The May 2015 change was necessary to comply with the terms of the Final Order No. 639314 issued in Cause No. PUD 201300217. That Order adopted the terms of a Joint Stipulation and Settlement Agreement ("Stipulation") that required PSO to move all fuel-related costs from base rates and riders into the FCA. PSO would have been out of compliance with a Commission order if the May 2015 change did not occur.

The January 2016 change is an example of PSO exercising the interim change provision in the FCA tariff to reset factors to address an over-recovery. In anticipation of base rates changing in the December or January timeframe (either through a final order or interim rates), PSO elected to delay the on-cycle fuel change in November to coincide with the base rate change to avoid changing customers' rates two times within a very short period. This also enabled customers to receive an overall decrease on their bills.

The November 2016 change was an annual, on-cycle factor change where factors were adjusted to reflect the then current deferred fuel balance and a new 12-month forecast.

Finally, the most recent change, May 2017, adjusted for an unanticipated increase in natural gas prices. The Company, subject to PUD's review and approval, again elected to use the interim factor provision rather than allowing a forecasted significant under-recovery to accumulate until November.

In summary, the four changes were made for legitimate reasons. Mr. Norwood's characterization is incomplete, perhaps because providing more background shows that there is no chronic issue with interim factor changes as he wants the Commission to believe.

According to Mr. Fate, PSO implements fuel changes pursuant to the terms of the FCA tariff, which require approval from the Director of PUD prior to implementation. To comply with the tariff, PSO submits the proposed factors and a detailed filing package that includes information such as an explanation of the factors driving the change, estimated customer impacts, forecasted expenses by fuel type, forecasted kwh sales by class per month, SPP expenses and revenues, as well as costs related to purchased power. PUD conducts at least one onsite audit to review the detailed information and ask questions of Company personnel. Following the audit, there are usually additional questions and information requests made through phone and email communication. It is only after this thorough review that PSO receives approval from PUD to change factors. Mr. Norwood's assertion is either a lack of understanding of the process or a complete disregard of PUD's oversight.

Regarding Mr. Norwood's claim that the current process lacks transparency, there is nothing that prevents parties, such as OIEC, from requesting the information that PUD reviews. In fact, PSO has consistently made information available to OIEC for review. It is unclear on what basis OIEC is claiming a lack of transparency or what it hopes to gain from a docketed proceeding.

A docketed proceeding is unnecessary and Mr. Norwood's testimony makes no mention of the fuel prudence review that are conducted on an annual basis.

Mr. Fate disagreed that interim adjustment should be prohibited. Interim changes undergo the same PUD review and approval process as the on-cycle change. The provision exists so that the over/under balance does not get too far in either direction. It protects both the customers and the Company from significant swings that can otherwise occur if the deferral/accrual is too long.

Mr. Fate could support a modification of the FCA to reduce the over-recovery period as long as it applies to under-recovery as well.

Regarding Mr. Norwood's recommendations to provide FCA reports to parties, PSO submits a fuel report to PUD on a monthly basis. Further, Mr. Norwood neglected to acknowledge that OIEC's counsel has been provided the same reports each month for years. PSO is more than willing to provide the reports to other requesting parties, but there should be no requirement to do so without request from a party.

Mr. Fate summarized Mr. Norwood's arguments related to PSO's SPPTC tariff by testifying that Mr. Norwood repeats the arguments that OIEC Witness Mark Garrett made in the first phase of rebuttal testimony. Specifically, he claims that PSO failed to show that the amount of SPP charges collected through the SPPTC during the test year were reasonable. According to Mr. Fate, he addressed these unfounded arguments in his rebuttal testimony filed on October 11, 2017, where he demonstrated that the necessary information was supplied in direct testimony and in supporting work papers. The direct testimony of PUD Witness Jason Chaplin confirms that the information was provided.

Mr. Fate further testified that Mr. Norwood's first modification to the SPPTC is to require annual SPPTC revisions to take place in a formal docket with review and approval by the Commission. This is an unnecessary step as the currently approved SPPTC tariff outlines a thorough process that requires review and approval by the PUD. Mr. Chaplin details this comprehensive review in both his responsive testimony and in discovery requests from OIEC.

Much like Mr. Norwood's FCA issues, it appears that he is seeking a solution where there is no problem.

Mr. Norwood's second recommendation is to require the Company to provide testimony in every base rate case addressing the reasonableness of third party charges recovered through the SPPTC tariff. PSO is agreeable to this as we already provide that level of support in both testimony and supporting workpapers.

Finally, his third recommendation is to eliminate the provision that allows for an interim factor change when an over-recovery or under-recovery exceeds 10% of the annual SPP expenses reflected in the SPPTC tariff. PSO has never exercised that provision and has no issue eliminating it.

According to Mr. Fate, Mr. Norwood mistakenly thinks that PSO is requesting an addition to the SPPTC Tariff that requires a broader review if a SPPTC revision results in an increase that exceeds 50%, and he recommends that the revision be denied. The provision is not being requested by PSO. It was recommended by PUD in Cause No. PUD 201500208 and approved by the Commission in Final Order No. 657871. In preparing Schedule N for the immediate Cause, the Company discovered that the new language was inadvertently omitted from the Cause No. PUD 201500208 compliance tariffs. Therefore, the language was added to Schedule N in the immediate Cause to comply with the aforementioned order.

Regarding Mr. Bohrmann's recommendation to move fuel handling costs to base rates, Mr. Fate testified that PSO's fuel handling costs were included in base rates until May 2015 when they were moved to the FCA to comply with Order No. 639314 of Cause No. PUD 201300217. As previously discussed, that order approved a Stipulation that required PSO to move all fuel-related costs, including fuel handling, out of base rates and into the FCA. The change was initially recommended by PUD and was agreed to by all parties to the Stipulation, including the AG's office.

PSO does not need fuel handling costs to be in base rates to incentivize management to keep costs low. PSO's fuel handling costs in Cause No. PUD 201300217 were approximately $4.8 million. In the immediate Cause, PSO has provided evidence that they have decreased to approximately $3.2 million. PSO is focused on controlling costs for customers no matter what the recovery mechanism.

Mr. Fate further testified that if the Commission accepts Mr. Bohrmann's recommendation to move fuel handling costs out of the FCA and into base rates, $3.2 million needs to be added to the overall revenue deficiency in order for PSO to be made whole.

A. NAIM HAKIMI

Mr. Hakimi did not agree with the recommendations made by AG Witness Alexander and OIEC Witness Norwood to change the Commission-approved OSS margin sharing arrangement to eliminate the 10% OSS margins retained by the Company.

According to Mr. Hakimi, the Company's existing OSS margin sharing credits almost all of those margin benefits (90%) to the customers, while allowing the Company to retain only 10%. This treatment of sharing OSS margins has successfully aligned the interests of the customer and the Company. The introduction of the SPP IM has reinforced the need for a sharing mechanism.

According to Mr. Hakimi, Mr. Alexander's characterization of the SPP IM is overly simplistic.

The new markets, policies, procedures, requirements and responsibilities resulting from the deployment of the SPP IM are designed to minimize the cost for the SPP footprint as a whole. SPP is not tasked with optimizing the off-system sales margins for any one participant – whether that participant happens to be PSO, or any one of the dozens of other market participants. Instead, SPP is tasked first with maintaining reliability, and then with matching generation supply with load demand based on market prices. Mr. Alexander's cursory description of the SPP IM severely overstates the role of SPP in regards to the optimization of PSO's OSS margins, while at the same time fails to recognize the major role of AEPSC and PSO personnel in all phases of the SPP IM.

Mr. Hakimi testified that the processes undertaken by Commercial Operations, on behalf of PSO, in preparing and submitting its Day-Ahead Generation Resource Offers provides a good illustration of active involvement in the market. For example, the SPP rules allow the Company four different ways to choose how its units will participate in the SPP IM day-ahead market.

The table below describes the various status designations available within the Unit Commitment Status process. As indicated by the "Not Participating" Commitment Status, PSO is not required to offer every available unit into the Day-Ahead market. Rather, it must offer sufficient resources to meet its forecasted net real-time load obligation and its load ratio share of the SPP Operating Reserve requirements. Such a unit designation could be made to participate in the Real-Time market while opting out of the Day-Ahead market.

COMMITMENT	
Market	Resource is available for SPP economic commitment if it is off-line.
Self	Market Participant (MP) is committing the Resource and SPP should include it as committed in either the Day-Ahead (DA) Market and/or Reliability Unit Commitment (RUC) as specified.
Reliability	Resource is off-line and only available for commitment by SPP if there is an anticipated reliability issue.
Outage	Resource is unavailable due to a planned, forced, maintenance or other approved outage. The outage must be documented using the outage scheduler tool
Not Participating	Resource is otherwise available but has elected not to participate in the DA Market. This option is not available for use for Real-Time BalancingMarket (RTBM) Offers. **MPRR174:** This status does not automatically prevent a Resource from being cleared for off-line Supplemental Reserve.

Additionally, AEPSC, on behalf of PSO, optimizes the value of PSO's generation by participating in both the energy markets and the operating reserve markets. When preparing bids, coordinating unit status, and determining which units, and under what parameters to offer to the market, AEPSC bases its economic decisions in light of the total revenue expected.

Mr. Hakimi also testified that the SPP IM Day-Ahead market is designed to determine the least-cost solution to meet the Energy Bids and Reserve requirements for the entire SPP footprint. Commercial Operations, on behalf of PSO, is able to provide additional benefits in the form of lower purchased power cost used to serve customers and in capturing additional opportunities for off-system sales margins by extending its analysis of a unit's economic operation over a period of at least seven days. The projected economics of PSO's generation over this longer period of time is a major factor in determining how to offer those units in the SPP IM Day-Ahead market.

Mr. Hakimi testified that the SPP IM requires a significant level of attention to detail and market intelligence to optimize PSO's resources and serve its load. The ability of the Commercial Operations personnel to get the most value for PSO's generating resources also enables them to maximize the off-system sales margins for the benefit of the customers of PSO and the Company.

PSO customers benefit through three basic methods according to Mr. Hakimi:

1. Actively engaging with the range of markets to develop an intimate understanding of the vast web of interconnected activities and the financial impacts of those various activities.
2. Actively working to minimize the costs associated with supplying the customers' needs within the SPP framework.
3. Prudently identifying the opportunities for optimizing OSS margins.

But the crucial relationship that ties all three elements together is that the whole is greater than the sum of its parts. The activities of each method learn from and complement the other methods. For example, if the Company is an active participant in the forward markets, then it makes it much more difficult for other market participants to discern the Company's overall position. However, if PSO scales back its activity in the off-system bilateral market, and only goes out to the market to purchase energy to secure amounts to replace generating units that have forced outages, the market will quickly realize that PSO is only going to the market after the loss of a unit. This will drive up the market prices and result in higher purchased power costs after loss of generating units in the balance of the day and forward daily markets.

Mr. Hakimi also testified that the SPP IM has increased many fold the volume of information that is to be submitted to the SPP compared to the pre-IM operations. Participation in the SPP IM has led to significantly more activity to prepare the bids and assess the results of the market and be ready to implement the market results. In addition to the day-ahead energy market that did not previously exist, there are four new markets for the ancillary services in the day-ahead and real-time markets. For the day-ahead market alone, 88 data points have to be submitted to SPP for each generating unit for a given day.

Mr. Hakimi testified that the AG and OIEC's recommendations will send a signal that the work of the AEPSC Commercial Operations is not considered as bringing significant value to PSO and will have a detrimental effect.

The testimony of Mr. Alexander would lead one to believe that PSO's units automatically run in the SPP market. His testimony does not address the complexity of the market and the significant amount of additional information and coordination required by the Commercial Operations personnel to achieve the best results for PSO from the market. He also fails to consider the interconnected nature of the various areas in the SPP IM. The existence of the OSS margin sharing is a key driver for not only the successful optimization of OSS margins in the SPP IM and in the bilateral OSS market, but full participation in the IM will minimize the fuel, purchased power costs, and other SPP IM market charges.

Mr. Hakimi's recommendation is that the Commission keep the existing sharing mechanism (90/10) in place to continue to emphasize aggressive pursuit of off-system sales for the benefit of both the customers and the Company. While the SPP IM has introduced a new method of dispatching the Company's resources, it has also provided additional challenges for the Company and does not inherently change the focus of the aggressive pursuit of OSS transactions by the Company, which can occur in many different forms. Eliminating the OSS margins retained by PSO will send a message to the Commercial Operations personnel that their activity in the SPP IM to achieve the highest possible OSS margins is not as significant as it was previously. The recommendation of Attorney General witness Mr. Alexander to modify the OSS margin sharing treatment is not in the best interests of PSO's customers and the Company and therefore should not be adopted.

Mr. Hakimi did not agree with Mr. Norwood's recommendation to exclude from OSS energy sales in the SPP IM. In addition to the reasons given for rejection of Mr. Alexander's recommendation, which also overlaps with Mr. Norwood's recommendation regarding OSS margin sharing, the removal of margins from energy sales in the SPP IM recommended by Mr. Norwood fails to recognize the interrelated nature of SPP IM energy transactions with other OSS margin accounts. The artificial separation recommended by Mr. Norwood could provide outcomes where the Company shares in the losses for one part of the OSS transaction, but does not receive a share of the positive revenue from other parts of the transaction. His recommendation should therefore be rejected by the Commission.

MAUREEN L. RENO

The DoD/FEA filed the Responsive Testimony of Maureen L. Reno on September 21, 2017, in Cause No. PUD 201700151. Ms. Reno filed Supplemental Testimony on October 5, 2017.

In its response to DoD/FEA Data Request 2-9, PSO witness Michael Vilbert stated that as of August 31, 2017, he would exclude Sempra Energy and Vectren Corp. from his sample of proxy companies, and he would include Duke Energy, NextEra Energy, and Unitil Corp.

In accordance with Mr. Wilbert's stated criteria, Ms. Reno had excluded Sempra Energy because it was recently involved in substantial merger and acquisition activities. However, Ms. Reno had included CVectren Corp. because she had been unaware of a news report dated August 22, 2017, indicating that, based on anonymous sources, Vectren was considering options including a potential sale. Based on this news report, Ms. Reno agreed with Mr. Vilbert that Vectren should be excluded from her sample of proxy companies. Ms. Reno also agreed with Mr. Vilbert that Duke Energy and NextEra Energy should be included because their mergers had been completed more than five years before. However, Ms. Reno disagreed with Mr. Vilbert regardeing Unitil Corp. because there is incomplete data on the company to calculate consistent results across all her analyses.

Ms. Reno performed the same analyses set forth in her Responsive Testimony with the modified sample (excluding Vectren and including Duke Energy and NextEra Energy). Applying her analysis to the modified sample proxy group yielded only marginal changes to her prior ROE estimates. Her new range, based on her DCF model sensitivities, became 7.39 percent to 8.62 percent, with a midpoint of 8.01 percent. In comparison, her original estimate range was 7.33 percent to 8.57 percent, with a midpoint of 7.95 percent. Since both the original midpoint and new midpoint round to 8.0 percent, her original ROE recommendation of 8.0 does not change.

ATTACHMENT "B"

HEARING EXHIBITS

Exhibit 1 – PSO's Response to Oklahoma Attorney General's 9th Data Requests
Exhibit 2 – PSO's Response to OIEC's 21st Data Requests
Exhibit 3 – PSO's Response OIEC's 14th Data Requests
Exhibit 4 - PSO's Response to Attorney General's 25th Data Requests
Exhibit 5 – PSO's Response to OIEF's 14th Data Requests
Exhibit 6 – No Exhibit
Exhibit 7 – PSO's Response to OIEC's 21st Data Requests
Exhibit 8 – PSO's Response to OIEC's 21st Data Requests
Exhibit 9 – PSO's Response to OIEC's 21st Data Requests
Exhibit 10 – PSO's Response to OIEC's 22nd Data Requests
Exhibit 11 – PSO's Response to OIEC's 17th Data Requests
Exhibit 12 – Exhibit MLR-1S, ROE Witness Comparisons
Exhibit 13 – Errata ROW and Recommendation
Exhibit 14 – Treasury Security Yield Curve
Exhibit 16 – Federal Reserve press release 9/20/17
Exhibit 17 – CNBC Article 10/18/17
Exhibit 18 – Industry Overview: Electric Utilities
Exhibit 19 – Forecasted Dividends ROE
Exhibit 20 – RRA Regulatory Focus
Exhibit 21 – Exhibit MFG-11, Schedule 1, ROE and ROR Analysis
Exhibit 22 – Exhibit MFG- SR-1, 30 Year Treasuries Interest Rates, 2015-2017
Exhibit 23 – How to Read a Value Line Report
Exhibit 24 – PSO's Response to OIEC's 5th Data Requests
Exhibit 25 – PSO's Response to OIEC's 19th Data Requests
Exhibit 26 – PSO's Response to OIEC's 5th Data Requests
Exhibit 27 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 28 – Public Utility Depreciation Practices
Exhibit 29 – Federal Reserve Bulletin
Exhibit 30 – PSO's Response to Attorney General's 19th Data Requests
Exhibit 31 – Response Testimony of David J. Garrett from Cause PUD 201500208
Exhibit 32 – PSO's Attorney General's 4th Data Requests
Exhibit 33 – Direct Testimony of John J. Spanos
Exhibit 34 – Direct Testimony of John J. Spanos
Exhibit 35 – Depreciation Systems
Exhibit 36 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 37 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 38 – PSO's Response to Attorney General's 27th Data Requests
Exhibit 39 – PSO's Response to Attorney General's 21st Data Requests
Exhibit 40 – Exhibit WWD-SR-2, PSO's Poles in Service 2002-2016
Exhibit 41 – PSO's Response to Attorney General's 27th Data Requests
Exhibit 42 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 43 – Attorney General's 23rd Set of Data Requests
Exhibit 44 – PSO's Response to Attorney General's 23rd Data Requests

Exhibit 45 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 46 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 46A- Updated Exhibit 46 with page that was left out of the originally offered exhibit
Exhibit 47 – Photos of Substation
Exhibit 48 – FERC Part 101, Conservation of Power and Water Resources
Exhibit 49 – PSO's Response to Attorney General's 26th Data Requests
Exhibit 50 – PSO's Response to Attorney General's 27th Data Requests
Exhibit 51 – PSO's Response to Attorney General's 27th Data Requests
Exhibit 52 – Responsive Testimony of William W. Dunkel
Exhibit 53 – WWD-SR-3, Percent Surviving at each age for 60 R 1
Exhibit 54 – Exhibit WWD-SR-4, Account 369.00 - Services
Exhibit 55 – Public Utility Depreciation Practices (NARUC)
Exhibit 56 – *Penn Sheraton Hotel v. Pennsylvania Public Utility Commission*
Exhibit 57 – *Lindhelmer vs. Illinois Bell Telephone Co.*
Exhibit 58 – Order of the Indiana Utility Regulatory Commission, Cause 44075
Exhibit 59- Revised Workpapers of D. Garrett
Exhibit 60- PSO's Response to Attorney General's 3rd Data Requests
Exhibit 61- PSO's Response to PUD's 2nd Data Requests
Exhibit 62- PSO's Response to the Attorney General's 6th Data Requests
Exhibit 63- PSO's Response to the Attorney General's 14th Data Requests
Exhibit 64- Exhibit TFB-SR-1, PSO Coal Consumption and Generation Mix Charts

ATTACHMENT "C"

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF PUBLIC SERVICE	)	
COMPANY OF OKLAHOMA, AN	)	
OKLAHOMA CORPORATION, FOR	)	**CAUSE NO. PUD 201700151**
AN ADJUSTMENT IN ITS RATES AND	)	
CHARGES AND THE ELECTRIC	)	
SERVICE RULES, REGULATIONS AND	)	
CONDITIONS OF SERVICE FOR	)	
ELECTRIC SERVICE IN THE STATE	)	
OF OKLAHOMA	)	

ALJ ACCOUNTING EXHIBIT
DECEMBER 11. 2017

Public Service Company of Oklahoma
Index to ALJ's Revenue Requirement Exhibit
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Schedule

A - 1	ALJ Revenue Requirement
B - 1	ALJ Pro Forma Rate Base
B - 2	ALJ Adjustments to Rate Base
B - 3	Explanation of ALJ Adjustments to Rate Base
E - 1	Cash Working Capital
F - 1	Capital Structure
H - 1	ALJ Pro Forma Operating Income Statement
H - 2	ALJ Operating Income Statement Adjustments
H - 3	Explanation of ALJ Adjustments to the Operating Income Statement
J - 1	ALJ Pro Forma Calculation of Taxable Income
J - 2	Interest Synchronization Calculation
J - 3	Adjustments to Current Income Tax Expense

Section A
Schedule 1

Public Service Company of Oklahoma
ALJ's Revenue Requirement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description	(A) Total Company Pro Forma Amount	Reference	(B) ALJ Total Company Adjusted Amount
1	Pro Forma Rate Base	$ 2,527,472,526	B-1	$ 2,440,996,529
2	Rate of Return	7.220%	F-1	6.734%
3	Operating Income Required	$ 182,483,516	1 times 2	$ 164,376,706
4	Pro Forma Operating Income	$ 78,943,783	H-1	$ 218,613,087
5	Difference	$ 103,539,733	3 minus 4	$ (54,236,381)
6	Revenue Conversion Factor	1.63867069		1.63076803
7	**PSO Pro Forma Base Rate Revenue Increase/(Decrease)**	**$ 169,667,526**	5 times 6	
8	**ALJ Pro Forma Base Rate Revenue Increase/(Decrease) Difference to Application**		5 times 6	**$ (88,446,956)**
9	**ALJ Pro Forma Base Rate Revenue Increase/(Decrease)**		7 plus 8	**$ 81,220,570**
10	Rev Inc Minus Difference	$ 66,127,793	7 minus 5	$ (34,210,575)
11	Return Requirement	$ 182,483,516	Line 3	$ 164,376,706
12	Total Operating Expense	$ 564,291,919	H-1	$ 507,269,898
13	Income Taxes	$ 74,840,260	H-1	$ 64,734,906
14	**Revenue Requirement**	$ 821,615,695	Line 8+9+10	$ 736,381,510

Section B
Schedule 1

Public Service Company of Oklahoma
ALJ Pro Forma Rate Base
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description	(A) Total Company Pro Forma Rate Base	(B) ALJ Total Company Test Year Adjustments	(C) ALJ Total Company Pro Forma Rate Base	(D) Oklahoma Allocation Factor	(E) ALJ Oklahoma Jurisdictional Rate Base
	Plant in Service:					
1	Plant in Service	$ 4,983,250,552	$ (14,083,293)	$ 4,969,167,259	99.96043421%	$ 4,967,201,169
2	Environmental Investment	$ -	$ -	$ -	0.00000000%	$ -
3	Less: Accumulated Depreciation	$ (1,502,061,083)	$ (32,673,645)	$ (1,534,734,728)	99.95754326%	$ (1,534,083,130)
4	Plant Held for Future Use	$ -	$ -	$ -	0.00000000%	$ -
5	Net Plant	$ 3,481,189,469	$ (46,756,938)	$ 3,434,432,531	99.96172608%	$ 3,433,118,039
	Other Rate Base Investment					
6	Cash Working Capital	$ (110,725,044)	$ 3,420,650	$ (107,304,394)	99.95680515%	$ (107,258,044)
7	Prepayments	$ 96,929,116	$ (344,729)	$ 96,584,387	99.96039220%	$ 96,546,132
8	Material & Supplies	$ 62,391,612	$ (5,596,294)	$ 56,795,318	99.95887809%	$ 56,771,963
	Rate Base Additions & Reductions					
9	Customer Deposits	$ (49,674,708)	$ (986,714)	$ (50,661,422)	100.00000000%	$ (50,661,422)
10	Customer Advances for Construction	$ -	$ -	$ -	0.00000000%	$ -
11	Off System Sales Trading Credits	$ (63,582)	$ 84,403	$ 20,821	99.94369994%	$ 20,809
12	Regulatory Assets	$ 127,004,496	$ 3,919,384	$ 130,923,880	99.96885747%	$ 130,883,107
13	Regulatory Liabilities/Deferred credit	$ (33,427,564)	$ (857,855)	$ (34,285,419)	99.96020114%	$ (34,271,774)
14	Accu. Deferred Income Taxes	$ (1,041,197,914)	$ (39,357,904)	$ (1,080,555,818)	99.96364631%	$ (1,080,162,996)
15	Excess Deferred Income Taxes	$ (4,937,384)	$ -	$ (4,937,384)	99.96364631%	$ (4,935,589)
16	Deferred Investment Tax Credits	$ (15,971)	$ -	$ (15,971)	99.96048177%	$ (15,965)
17	**Rate Base**	$ 2,527,472,526	$ (86,475,997)	$ 2,440,996,529	99.96059089%	$ 2,440,034,260

Public Service Company of Oklahoma
Explanation of ALJ Adjustments to Rate Base
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Section B
Schedule 2

Line No.	Description	(A) Total Company Pro Forma Rate Base	(B) ALJ Adjustment No. 1	(C) ALJ Adjustment No. 2	(D) ALJ Adjustment No. 3	(E) ALJ Adjustment No. 4	(F) ALJ Adjustment No. 5	(G) ALJ Adjustment No. 6	(H) ALJ Adjustment No. 7
	Plant in Service:								
1	Plant in Service	$ 4,983,250,552			$ 69,196,225				
2	Environmental Investment	$ -							
3	Less: Accumulated Depreciation	$ (1,502,061,083)							
4	Plant Held for Future Use	$ -							
5	Net Plant	$ 3,481,189,469	$ -	$ -	$ 69,196,225	$ -	$ -	$ -	$ -
	Other Rate Base Investment								
6	Cash Working Capital	$ (110,725,044)	$ 3,420,650						
7	Prepayments	$ 96,929,116						$ (344,729)	
8	Material & Supplies	$ 62,391,612				$ (5,886,208)	$ 289,914		
9	Fuel Inventories	$ -							
	Rate Base Additions & Reductions								
10	Customer Deposits	$ (49,674,708)		$ (986,714)					
11	Customer Advances for Construction	$ -							
12	Off System Sales Trading Credits	$ (63,582)							$ 84,403
13	Regulatory Assets	$ 127,004,496							
14	Regulatory Liabilities/Deferred credits	$ (33,427,564)							
15	Accu. Deferred Income Taxes	$ (1,041,197,914)							
16	Excess Deferred Income Taxes	$ (4,937,384)							
17	Deferred Investment Tax Credits	$ (15,971)							
18	Rate Base	$ 2,527,472,526	$ 3,420,650	$ (986,714)	$ 138,392,450	$ (5,886,208)	$ 289,914	$ (344,729)	$ 84,403

Public Service Company of Oklahoma
Explanation of ALJ Adjustments to Rate Base
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Section B
Schedule 2

Line No.	Description	(I) ALJ Adjustment No. 8	(J) ALJ Adjustment No. 9	(K) ALJ Adjustment No. 10	(L) ALJ Adjustment No. 11	(M) ALJ Adjustment No. 12	(N) ALJ Adjustment No. 13	(O) ALJ Adjustment No. 14	(P) ALJ Adjustment No. 15	(Q) ALJ Adjustment No. 16
	Plant in Service:									
1	Plant in Service									
2	Environmental Investment									
3	Less: Accumulated Depreciation				$ (32,673,645)					
4	Plant Held for Future Use									
5	Net Plant	$ -	$ -	$ -	$ (32,673,645)	$ -	$ -	$ -	$ -	$ -
	Other Rate Base Investment									
6	Cash Working Capital									
7	Prepayments									
8	Material & Supplies									
9	Fuel Inventories									
	Rate Base Additions & Reductions									
10	Customer Deposits									
11	Customer Advances for Construction									
12	Off System Sales Trading Credits									
13	Regulatory Assets			$ 4,625,004		$ 13,082,073	$ 968,689	$ 531,524	$ (1,139,884)	$ (12,738,287)
14	Regulatory Liabilities/Deferred credits	$ (69,740)	$ (788,115)							
15	Accu. Deferred Income Taxes									
16	Excess Deferred Income Taxes									
17	Deferred Investment Tax Credits									
18	Rate Base	$ (69,740)	$ (788,115)	$ 4,625,004	$ (32,673,645)	$ 13,082,073	$ 968,689	$ 531,524	$ (1,139,884)	$ (12,738,287)

Public Service Company of Oklahoma
Explanation of ALJ Adjustments to Rate Base
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Section B
Schedule 2

Line No.	Description	(R) ALJ Adjustment No. 17	(S) ALJ Adjustment No. 18	(T) ALJ Adjustment No 19	(U) ALJ Adjustment No. 20	(W) Total ALJ Adjustments	(X) ALJ Total Company Pro Forma Rate Base
	Plant in Service:						
1	Plant in Service			$ (83,279,518)		$ (14,083,293)	$ 4,969,167,259
2	Environmental Investment					$ -	$ -
3	Less: Accumulated Depreciation					$ (32,673,645)	$ (1,534,734,728)
4	Plant Held for Future Use					$ -	$ -
5	Net Plant	$ -	$ -	$ (83,279,518)	$ -	$ (46,756,938)	$ 3,434,432,531
	Other Rate Base Investment						
6	Cash Working Capital					$ 3,420,650	$ (107,304,394)
7	Prepayments					$ (344,729)	$ 96,584,387
8	Material & Supplies					$ (5,596,294)	$ 56,795,318
9	Fuel Inventories					$ -	$ -
	Rate Base Additions & Reductions						
10	Customer Deposits					$ (986,714)	$ (50,661,422)
11	Customer Advances for Construction					$ -	$ -
12	Off System Sales Trading Credits					$ 84,403	$ 20,821
13	Regulatory Assets	$ (7,773,107)			$ 6,363,372	$ 3,919,384	$ 130,923,880
14	Regulatory Liabilities/Deferred credits					$ (857,855)	$ (34,285,419)
15	Accu. Deferred Income Taxes		$ (39,357,904)			$ (39,357,904)	$ (1,080,555,818)
16	Excess Deferred Income Taxes					$ -	$ (4,937,384)
17	Deferred Investment Tax Credits					$ -	$ (15,971)
18	Rate Base	$ (7,773,107)	$ (39,357,904)	$ (83,279,518)	$ 6,363,372	$ (86,475,997)	$ 2,440,996,529

Section B
Schedule 3

Public Service Company of Oklahoma
Explanation of ALJ Adjustments to Rate Base
Test Year Ended December 31, 2016
Cause No. PUD 201700151

			(A)		(B)		(C)
ALJ Adj.					Impact On Rate Base		
No.	Adjustment Description		Increase		Decrease		Net Incr/(Decr)
1	Adjust Cash Working Capital	$	3,420,650	$	-	$	3,420,650
2	Customer Deposits - ALJ 50	$	-	$	(986,714)	$	(986,714)
3	To adjust Plant in Service to 6/30/17 Balances - ALJ 11	$	69,196,225	$	-	$	69,196,225
4	Materials and Supplies - ALJ 20	$	-	$	(5,886,208)	$	(5,886,208)
5	Fuel Inventories - ALJ 21	$	289,914	$	-	$	289,914
6	Prepayment Expense - ALJ 16	$	-	$	(344,729)	$	(344,729)
7	Off-System Trading Deposits - ALJ 23	$	84,403	$	-	$	84,403
8	Adjust CIAC to 6/30/17 Balances - ALJ 31	$	-	$	(69,740)	$	(69,740)
9	Deferred Pole Attachment Regulatory Liability - ALJ 40	$	-	$	(788,115)	$	(788,115)
10	Deferred Storm Expense Regulatory Asset - ALJ 34	$	4,625,004	$	-	$	4,625,004
11	Accumulated Depreciation - ALJ 14	$	-	$	(32,673,645)	$	(32,673,645)
12	Deferred Enviro. - Correct 12/31/16 Balances – ALJ 38A	$	13,082,073	$	-	$	13,082,073
13	Deferred Enviro. - Reverse Half Year 2018 Amortization – ALJ 38B	$	968,689	$	-	$	968,689
14	Deferred Enviro. - Correct Company Exhibit Errors – ALJ 38C	$	531,524	$	-	$	531,524
15	Deferred Enviro. - Remove Carrying Costs thru 6/30/17 - ALJ 38D	$	-	$	(1,139,884)	$	(1,139,884)
16	Deferred Enviro. - Remove Estimated Costs 7/1/17 - 12/31/17 - ALJ 38E	$	-	$	(12,738,287)	$	(12,738,287)
17	Non-AMI Meters - Update to 6/30/17 - ALJ 42	$	-	$	(7,773,107)	$	(7,773,107)
18	Accumulated Deferred Income Tax - ALJ 26	$	-	$	(39,357,904)	$	(39,357,904)
19	Remove Return on NE 4 as of 6/30/17 - ALJ 59	$	-	$	(83,279,518)	$	(83,279,518)
20	Deferred Severe Storm Expense - ALJ 47	$	6,363,372	$	-	$	6,363,372
	Total Rate Base Adjustments	**$**	**98,561,854**	**$**	**(185,037,851)**	**$**	**(86,475,997)**

Section E
Schedule 1

Public Service Company of Oklahoma
Cash Working Capital
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description	(A) Total Company Pro Forma	(B) Adjustments	(C) ALJ Total Company Pro Forma	(D) Net Lead/Lag Days	(E) ALJ Adjusted CWC
	Cost of Service					
1	Fuel & Purchase Power					
2	Coal	$ 51,773,532	$ -	$ 51,773,532	(12.1200)	$ (1,719,165)
3	Oil	$ 348,768	$ -	$ 348,768	(10.4400)	$ (9,976)
4	Gas	$ 102,768,020	$ -	$ 102,768,020	(37.4400)	$ (10,541,465)
5	Purchased Power	$ 467,644,014	$ -	$ 467,644,014	(25.0600)	$ (32,107,285)
6	Other O & M	$ 328,488,268	$ (20,057,561)	$ 308,430,707	(35.9500)	$ (30,378,312)
7	Federal Income Tax-Current	$ (27,977,860)	$ (8,550,684)	$ (36,528,544)	(33.6800)	$ 3,370,634
8	Federal Income Tax-Deferred	$ 77,402,260	$ -	$ 77,402,260	0.0000	$ -
9	State Income Tax-Current	$ (1,920,410)	$ (1,554,670)	$ (3,475,080)	(33.6800)	$ 320,659
10	State Income Tax-Deferred	$ 8,472,557	$ -	$ 8,472,557	0.0000	$ -
11	Taxes other than Income	$ 40,586,901	$ (49,673)	$ 40,537,228	(187.66)	$ (20,841,688)
12	Interest on Customer Deposits	$ 846,779	$ -	$ 846,779	(163.94)	$ (380,331)
13	Depreciation Expense	$ 180,664,161	$ (24,244,758)	$ 156,419,403	0.0000	$ -
14	Interest Long Term Debt	$ 59,901,099	$ (2,086,096)	$ 57,815,003	(85.2300)	$ (13,500,199)
15	Preferred Dividends	$ -	$ -	$ -	0.0000	$ -
16	Return	$ 122,582,418	$ -	$ 122,582,418	0.0000	$ -
17	Subtotal	$ 1,351,679,408	$ (54,457,346)	$ 1,288,749,505		$ (105,787,128)
18	Working Funds and Other					$ (1,517,266)
19						$ (107,304,394)
20				Company Pro Forma		$ (110,725,044)
21				**ALJ Adjustment to Rate Base**		$ 3,420,650
22						$ 3,420,650
23						$ (107,304,394)

0

Section F
Schedule 1

Public Service Company of Oklahoma
Capital Structure
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description	(A) Company Capitalization Ratios	(B) Company Cost of Capital	(C) Company Weighted Cost of Capital
	PSO Requested Capital Structure:			
1	Long Term Debt	51.4900%	4.6000%	2.3685%
2	Preferred Stock	0.0000%	0.0000%	0.0000%
3	Common Stock	48.5100%	**10.0000%**	4.8510%
4	Total	100.0000%		7.2195%

Line No.	Description	ALJ Capitalization Ratios	ALJ Cost of Capital	ALJ Weighted Cost of Capital
	ALJ Requested Capital Structure:			
1	Long Term Debt	51.4900%	4.6000%	2.3685%
2	Preferred Stock	0.0000%	0.0000%	0.0000%
3	Common Stock	48.5100%	**9.0000%**	4.3659%
4	Total	100.0000%		6.7344%

Section II
Schedule 1

Public Service Company of Oklahoma
ALJ Pro Forma Operating Income Statement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description	(A) Total Company Pro Forma Income Statement	(B) Total ALJ Adjustments	(C) ALJ Total Company Pro Forma Income Statement	(D) ALJ Recommended Increase	(E) ALJ Pro Forma Results	(F) Oklahoma Allocation Factor	(G) ALJ Oklahoma Jurisdiction Amounts
1	Operating Revenue:							
2	Electric	$ 821,615,695	$ 3,212,771	$ 824,828,466	$ (88,446,956)	$ 736,381,510	99.95891628%	$ 736,078,977
3	Other	$ -	$ -	$ -		$ -	0.00000000%	$ -
4	Total Operating Revenue	$ 821,615,695	$ 3,212,771	$ 824,828,466	$ (88,446,956)	$ 736,381,510		$ 736,078,977
5	Operating Expense:							
6	Fuel & Purchased Power	$ -	$ -	$ -	$ -	$ -	100.00000000%	$ -
7	Other O&M	$ 340,540,556	$ (20,057,561)	$ 320,482,995	$ -	$ 320,482,995	99.95668322%	$ 320,344,172
8	Other Expenses	$ 2,500,301	$ (12,670,029)	$ (10,169,728)	$ -	$ (10,169,728)	99.94232571%	$ (10,163,863)
9	Other Taxes	$ 40,586,901	$ (49,673)	$ 40,537,228	$ -	$ 40,537,228	99.96035419%	$ 40,521,157
10	Depreciation & Amortization	$ 180,664,161	$ (24,244,758)	$ 156,419,403	$ -	$ 156,419,403	99.96088078%	$ 156,358,213
11	Interest on Special Items	$ -	$ -	$ -	$ -	$ -		$ -
12	Total Operating Expenses	$ 564,291,919	$ (57,022,021)	$ 507,269,898	$ -	$ 507,269,898	99.95855875%	$ 507,059,679
13	Operating Income Before Income tax	$ 257,323,776	$ 60,234,792	$ 317,558,568	$ (88,446,956)	$ 229,111,612	99.95970785%	$ 229,019,298
14	Less: Income Tax	$ 74,840,260	$ 24,105,221	$ 98,945,481	$ (34,210,575)	$ 64,734,906	99.96002498%	$ 64,734,906
15	Operating Income	$ 182,483,516	$ 36,129,571	$ 218,613,087	$ (54,236,381)	$ 164,376,706	99.94383997%	$ 164,284,392

Public Service Company of Oklahoma
ALJ Adjustments to Operating Income Statement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Section H
Schedule 2

Line No.	Description		(A) Total Company Pro Forma Income Statement		(B) ALJ Adjustment No. 1		(C) ALJ Adjustment No. 2		(D) ALJ Adjustment No. 3		(E) ALJ Adjustment No. 4		(F) ALJ Adjustment No. 5
1	Operating Revenue:												
2	Electric	$	821,615,695										
3	Other	$	-										
4	Total Operating Revenue	$	821,615,695	$	-	$	-	$	-	$	-	$	-
5	Operating Expense:												
6	Fuel & Purchased Power	$	-										
7	Other O&M	$	340,540,556	$	(1,244,786)	$	(117,876)	$	(8,264,000)	$	(7,970,720)	$	(96,780)
8	Other Expenses	$	2,500,301										
9	Other Taxes	$	40,586,901										
10	Depreciation & Amortization	$	180,664,161										
11	Interest on Special Items	$	-										
12	Total Operating Expenses	$	564,291,919	$	(1,244,786)	$	(117,876)	$	(8,264,000)	$	(7,970,720)	$	(96,780)
13	Operating Income Before Income ta›	$	257,323,776	$	1,244,786	$	117,876	$	8,264,000	$	7,970,720	$	96,780
14	Less: Income Tax	$	74,840,260										
15	Operating Income	$	182,483,516										

Public Service Company of Oklahoma
ALJ Adjustments to Operating Income Statement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Section II
Schedule 2

Line No.	Description	(G) ALJ Adjustment No. 6	(H) ALJ Adjustment No. 7	(I) ALJ Adjustment No. 8	(J) ALJ Adjustment No. 9	(K) ALJ Adjustment No. 10	(L) ALJ Adjustment No. 11	(M) ALJ Adjustment No. 12	(N) ALJ Adjustment No. 13
1	Operating Revenue:								
2	Electric								$ 505,152
3	Other								
4	Total Operating Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 505,152
5	Operating Expense:								
6	Fuel & Purchased Power								
7	Other O&M	$ (253,082)			$ (2,110,317)				
8	Other Expenses		$ (2,219,213)	$ (13,994,625)					
9	Other Taxes								
10	Depreciation & Amortization					(1,380,888)	$ (17,870,697)	$ (4,993,173)	
11	Interest on Special Items								
12	Total Operating Expenses	$ (253,082)	$ (2,219,213)	$ (13,994,625)	$ (2,110,317)	$ (1,380,888)	$ (17,870,697)	$ (4,993,173)	$ -
13	Operating Income Before Income ta	$ 253,082	$ 2,219,213	$ 13,994,625	$ 2,110,317	$ 1,380,888	$ 17,870,697	$ 4,993,173	$ 505,152
14	Less: Income Tax								
15	Operating Income								

Public Service Company of Oklahoma
ALJ Adjustments to Operating Income Statement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Section II
Schedule 2

Line No.	Description	(O) ALJ Adjustment No. 14	(P) ALJ Adjustment No. 15	(Q) ALJ Adjustment No. 16	(S) Adjustment Income Tax	(T) Total Company Adjustments	(U) Pro Forma Income Statement
1	Operating Revenue:						
2	Electric	$ 2,707,619				$ 3,212,771	$ 824,828,466
3	Other					$ -	$ -
4	Total Operating Revenue	$ 2,707,619	$ -	$ -		$ 3,212,771	$ 824,828,466
5	Operating Expense:						
6	Fuel & Purchased Power					$ -	$ -
7	Other O&M					$ (20,057,561)	$ 320,482,995
8	Other Expenses			$ 3,543,809		$ (12,670,029)	$ (10,169,728)
9	Other Taxes		$ (49,673)			$ (49,673)	$ 40,537,228
10	Depreciation & Amortization					$ (24,244,758)	$ 156,419,403
11	Interest on Special Items					$ -	$ -
12	Total Operating Expenses	$ -	$ (49,673)	$ 3,543,809		$ (57,022,021)	$ 507,269,898
13	Operating Income Before Income ta›	$ 2,707,619	$ 49,673	$ (3,543,809)		$ 60,234,792	$ 317,558,568
14	Less: Income Tax				$ 24,105,221	$ 24,105,221	$ 98,945,481
15	Operating Income				$ (24,105,221)	$ 36,129,571	$ 218,613,087

Section H
Schedule 3

Public Service Company of Oklahoma
Explanation of ALJ Adjustments to Operating Income Statement
Test Year Ended December 31, 2016
Cause No. PUD 201700151

ALJ Adj. No.	Adjustment Description		(A) Decrease		(B) Increase		(C) Net Incr/(Decr)
			IMPACT ON REVENUE REQUIREMENT				
1	Factoring Expense Adjustment	$	(1,244,786)	$	-	$	(1,244,786)
2	Dues and Donation - ALJ 88 B	$	(117,876)	$	-	$	(117,876)
3	Storm Cost - ALJ 90-92	$	(8,264,000)	$	-	$	(8,264,000)
4	Incentive Compensation (STI & LTI) - ALJ 83	$	(7,970,720)	$	-	$	(7,970,720)
5	Supplemental Executive Retirement Plan (SERP) PSO - ALJ 80	$	(96,780)			$	(96,780)
6	Supplemental Executive Retirement Plan (SERP) AEPSC - ALJ 80	$	(253,082)	$	-	$	(253,082)
7	Decrease Regulatory Debits Expense to Correct Non-AMI Meter Amortization Rate - ALJ 44	$	(2,219,213)	$	-	$	(2,219,213)
8	SPP Schedule 9 NITS Transmission Expense - ALJ 94	$	(13,994,625)	$	-	$	(13,994,625)
9	Generation O&M Expense - ALJ 97	$	(2,110,317)	$	-	$	(2,110,317)
10	Decrease Production Depreciation due to PSO's extension of the useful life of the Oklaunion ARO from 2020 to 2046 - ALJ 38F		(1,380,888)	$	-	$	(1,380,888)
11	Depreciation Expense Accounts 356, 362, 366, 367, 373 and 390 - ALJ 107	$	(17,870,697)	$	-	$	(17,870,697)
12	Depreciation Expense Account 303 - ALJ 107	$	(4,993,173)			$	(4,993,173)
13	Update Non-fuel Base Revenue to 6/30/17 - ALJ 108			$	505,152	$	505,152
14	Pro Forma Revenue Adjustment - ALJ 109	$	-	$	2,707,619	$	2,707,619
15	Ad Valorem Taxes - Update to 6/30/17 - ALJ 98	$	(49,673)	$	-	$	(49,673)
16	Add Return of NE4 Regulatory Asset - ALJ 56	$	-	$	3,543,809	$	3,543,809
	Total Adjustments to operating income	$	**(60,565,830)**	$	**6,756,580**	$	**(53,809,250)**

Section J
Schedule 1

Public Service Company of Oklahoma
ALJ'S Pro Forma Calculation of Taxable Income
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description	(A) Total Company Pro Forma Amount	(B) ALJ Test Year Adjustment	(C) ALJ Total Company Pro Forma Amount	(D) Allocation Factor	(E) Oklahoma Jurisdictional Amount
1	Operating income before taxes	$ 257,323,776	$ 60,234,792	$ 317,558,568		$ 229,111,612
2	Interest-Long Term	$ 59,901,099	$ (2,086,096)	$ 57,815,003		$ 57,815,003
	Permanent Differences:					
3	50% Meal & Enter. Disallowance	$ 441,217	$ -	$ 441,217		$ 441,217
4	Book Depr. On Flo Thru Basis Diff	$ 2,844,000	$ -	$ 2,844,000		$ 2,844,000
5	SFAS 106 Post Retire Ben Medicare Subsidy	$ -	$ -	$ -		$ -
6	BIP AFUDC EQ. Amort	$ -	$ -	$ -		$ -
7	Preferred Dividend Credit	$ -	$ -	$ -		$ -
8	Manufacturing Deduction	$ -	$ -	$ -		$ -
9	Other	$ -	$ -	$ -		$ -
		$ -	$ -	$ -		$ -
10	Total Permanent Differences	$ 3,285,217	$ -	$ 3,285,217		$ 3,285,217
11	Book Taxable Income	$ 200,707,894	$ 62,320,888	$ 263,028,782		$ 174,581,826
12	Total Income Tax at Combined Rate of 38.6792014% 1.63076803	$ 77,632,208	$ 24,105,221	$ 101,737,429		$ 67,526,854
13	Other Differences:					
	Reversal of Reg Asset/Liab Excess ADIT	$ (672,000)	$ -	$ (672,000)		$ (672,000)
14	Amort of Def ITC - Federal	$ (2,066,383)	$ -	$ (2,066,383)		$ (2,066,383)
15	Amort of Def ITC - State	$ (82,408)	$ -	$ (82,408)		$ (82,408)
16	Def FIT on Def ITC - State	$ 28,843	$ -	$ 28,843		$ 28,843
17	Prior Period Adjustments	$ -	$ -	$ -		$ -
18	Total Other Differences	$ (2,791,948)	$ -	$ (2,791,948)		$ (2,791,948)
19	Total Federal and State Current and Deferred Income Taxes	$ 74,840,260	$ 24,105,221	$ 98,945,481		$ 64,734,906

Section J
Schedule 2

Public Service Company of Oklahoma
Interest Synchronization Calculation
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Description		(A) ALJ Total Company Pro Forma
1	Rate Base (Sec B, Schedule 1)	$	2,440,996,529
2	Weighted Cost of Debt (Sec F, Schedule 1)		2.3685%
3	Interest On Debt	$	57,815,003
4	Adjusted Interest on Debt	$	57,815,003

Section J
Schedule 3

Public Service Company of Oklahoma
Adjustments to Current Income Tax Expense
Test Year Ended December 31, 2016
Cause No. PUD 201700151

Line No.	Adjustment Description	(A) Increase	(B) Decrease
	ALJ Adjustment No. 1		
1	To adjust Current Income Tax Expense for ALJ's Pro Forma Interest Expense	$ (2,086,096)	

SOAH DOCKET NO. 473-12-2979
PUC DOCKET NO. 39896

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES, RECONCILE FUEL COSTS, AND OBTAIN DEFERRED ACCOUNTING TREATMENT	**§ § § § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

PROPOSAL FOR DECISION

TABLE OF CONTENTS

List of Acronyms and Defined Terms

TERM	DEFINITION
12CP	12 Coincident Peak
A&E 4CP	Average and Excess, 4 Coincident Peak
A&P	Average and Single Coincident Peak
ADFIT	Accumulated Deferred Federal Income Tax
AFC	Additional Facilities Charge
AFUDC	Allowance for Funds Used During Construction
ALJs	Administrative Law Judges
BCII/U3	Big Cajun II, Unit 3
Brazos	Brazos Electric Cooperative, Inc.
Calpine	Calpine Energy Services
Carville Contract	Contract for the purchase of 485 MW of capacity from Calpine's Carville Energy Center
CAPM	Capital Asset Pricing Model
CenterPoint	CenterPoint Energy Houston Electric, LLC
CGS	Competitive Generation Service
CI	Conformance Index
Cities	Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Dayton, Groves, Houston, Huntsville, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Rose City, Pinehurst, Port Arthur, Port Neches, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange, Texas
Commission	Public Utility Commission of Texas
Company	Entergy Texas, Inc.
CP	Coincident Peak
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
DCRF	Distribution Cost Recovery Factor
DOE	United States Department of Energy
DOJ	United States Department of Justice
EAI	Entergy Arkansas, Inc.
EA WBL Contract	2009 Contract between ETI and EAI for Wholesale Base Load Resources
EGSI	Entergy Gulf States, Inc., predecessor to ETI
EGSL	Entergy Gulf States Louisiana, LLC
ELL	Entergy Louisiana, Inc.
EMI	Entergy Mississippi, Inc.
Enbridge Contract	Long-term Gas Supply Contract between ETI and Enbridge Pipeline, L.P.
ENOI	Entergy New Orleans, Inc.
Entergy	Entergy Corporation
ESI	Entergy Services, Inc.

TERM	DEFINITION
ETEC	East Texas Electric Cooperative, Inc.
ETI	Entergy Texas, Inc.
FAS 106	FASB Statement No. 106
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN 48	Financial Interpretation Number 48
GAAP	Generally Accepted Accounting Principles
GDP	Gross Domestic Product
GS	General Service
GSU	Gulf States Utilities Company
Iowa Curves	Various Known Patterns of Industrial Asset Mortality Rates
IRS	Internal Revenue Service
ISB	Intra-System Bill
Jenkins Class Action	Class action lawsuit filed in Texas district court in 2003 on behalf of all Texas retail customers served by ETI's predecessor-in-interest, EGSI
Kroger	The Kroger Co.
kW	Kilowatt
kWh	Kilowatt-hour
LED	Light Emitting Diode
LGS	Large General Service
LIPS	Large Industrial Power Service
MFF	Municipal Franchise Fees
MGRT	Miscellaneous Gross Receipts Tax
MISO	Midwest Independent Transmission System Operator, Inc.
MSS-2	Schedule MSS-2 of the Entergy System Agreement
MW	Megawatt
Moody's	Moody's Investors Service
MWh	Megawatt-hour
NARUC	National Association of Regulatory Utility Commissioners
Nelson	Nelson 6, a 550 MW Unit located in Westlake, Louisiana
O&M	Operations and Maintenance
OATT	Open Access Transmission Tariff
OPC	Office of Public Utility Counsel
PFD	Proposal for Decision
PPCCs	Purchased Power Capacity Costs
PPR	Purchased Power Rider
PUC	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act
Rate Year	June 1, 2012, through May 31, 2013
Reconciliation Period	July 1, 2009, through June 30, 2011
RECs	Renewable Energy Credits
Reserve	Strategic Petroleum Reserve

TERM	DEFINITION
River Bend	River Bend Nuclear Generating Station Unit No. 1
ROE	Return on Equity
RRC	Railroad Commission of Texas
RS	Residential Service
RTO	Regional Transmission Organization
S&P	Standard & Poor's
SFAS	Statement of Financial Accounting Standards
SIPS	Schedulable Intermittent Pumping Service
SMS	Standby Maintenance Service
SOAH	State Office of Administrative Hearings
Spindletop Facility	Spindletop Gas Storage Facility
SRMPA	Sam Rayburn Municipal Power Agency
Staff	Staff of the Public Utility Commission of Texas
State Agencies	State of Texas State Agencies
T&D	Transmission and Distribution
TCRF	Transmission Cost Recovery Factor
Test Year	July 1, 2010, through June 30, 2011
TIEC	Texas Industrial Energy Consumers
Value Line	Value Line Investment Survey
Wal-Mart	Wal-Mart Stores, LLC, and Sam's East, Inc.
Zacks	Zacks Investment Service

SOAH DOCKET NO. 473-12-2979
PUC DOCKET NO. 39896

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES, RECONCILE FUEL COSTS, AND OBTAIN DEFERRED ACCOUNTING TREATMENT	§ § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

PROPOSAL FOR DECISION

I. INTRODUCTION [Germane to Preliminary Order Issue Nos. 1 and 4]

Entergy Texas, Inc. (ETI or the Company) is an investor-owned electric utility with a retail service area located in southeastern Texas. ETI serves retail and wholesale electric customers in Texas. As of June 30, 2011, ETI served approximately 412,000 Texas retail customers. The Federal Energy Regulatory Commission (FERC) regulates ETI's wholesale electric operations.

On November 28, 2011, ETI filed an application requesting approval of: (1) a proposed increase in annual base rate revenues of approximately $111.8 million over adjusted revenues for the period beginning July 1, 2010, and ending June 30, 2011 (Test Year); (2) a set of proposed tariff schedules presented in the Electric Utility Rate Filing Package for Generating Utilities accompanying ETI's application and including new riders for recovery of costs related to purchased power capacity and renewable energy credit requirements; (3) a request for final reconciliation of ETI's fuel and purchased power costs for the reconciliation period from July 1, 2009, to June 30, 2011 (Reconciliation Period); and (4) certain waivers to the instructions in Rate Filing Package Schedule V accompanying ETI's application. The rate year for ETI's proposed changes is June 1, 2012, through May 31, 2013 (Rate Year).[1] On April 13, 2012, adjusted its request for a proposed increase in annual base rate revenues to approximately $104.8 million over adjusted Test Year revenues.

[1] During the hearing the parties used the term "Rate Year" to refer to the period June 2012 through May 2013. This was intended to represent the first 12 months of the rates adopted in this case. However, the rates in this case will not go into effect (as temporary rates) until at least June 30, 2012. Nevertheless, for purposes of this PFD, Rate Year will refer to the period June 2012 through May 2013.

II. JURISDICTION AND NOTICE

The Public Utility Commission of Texas (Commission or PUC) has jurisdiction over ETI and this rate case application pursuant to Public Utility Regulatory Act (PURA) §§ 14.001, 32.001, 33.002, and 35.004. The State Office of Administrative Hearings (SOAH) has jurisdiction over the contested case hearing, including the preparation of the proposal for decision (PFD) pursuant to PURA § 14.053 and Tex. Gov't Code § 2003.049(b). Those municipalities in ETI's service area that have not surrendered jurisdiction to the Commission continue to have exclusive original jurisdiction over ETI's rates, operations, and services in their respective municipalities pursuant to PURA § 33.001. When ETI filed its application with the Commission, it also filed the application with its original jurisdiction cities. Pursuant to PURA §§ 32.001(b), 33.051, and 33.053, ETI appealed the actions of the original jurisdiction cities to the Commission and had those appeals consolidated with this docket.

ETI's notice of its application and notice of the hearing were not contested and, therefore, do not require further discussion but will be addressed in the proposed findings of fact and conclusions of law.

III. PROCEDURAL HISTORY

As noted above, ETI filed its application and rate filing package on November 28, 2011. On November 29, 2011, the Commission referred this proceeding to SOAH. On December 19, 2011, the Commission issued its Preliminary Order setting forth 31 issues to be addressed in this proceeding. On January 19, 2012, the Commission issued a Supplemental Preliminary Order listing two additional issues to be considered and stating that ETI's request for a purchased power cost recovery rider should not be addressed in this docket.

On September 2, 2011, ETI filed an application requesting authority to defer accounting related to its proposed transition to membership in the Midwest Independent Transmission System Operator, Inc. (MISO). This proceeding was docketed as Docket No. 39741. On November 22, 2011, the Commission issued its Preliminary Order in Docket No. 39741 addressing certain threshold legal/policy questions and setting forth nine issues to be addressed in the proceeding. On December 20, 2011, Docket No. 39741 was consolidated into this docket for all purposes.

The following entities were granted intervenor status in this case: Texas Industrial Energy Consumers (TIEC); State of Texas State Agencies (State Agencies); Office of Public Utility Counsel (OPC); the Cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Dayton, Groves, Houston, Huntsville, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Rose City, Pinehurst, Port Arthur, Port Neches, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange (Cities); The Kroger Co. (Kroger); Wal-Mart Stores, LLC, and Sam's East, Inc. (Wal-Mart); East Texas Electric Cooperative, Inc. (ETEC); and the United States Department of Energy (DOE).

The hearing on the merits convened before SOAH Administrative Law Judges (ALJs) Thomas H. Walston, Steven D. Arnold, and Hunter Burkhalter on April 24, 2012, and continued through May 4, 2012. The record remained open for the filing of post-hearing briefs and proposed finds of fact and conclusions of law. On June 8, 2012, the parties filed proposed finds of fact and conclusions of law and the record closed. As permitted by P.U.C. PROC. R. 22.261(a), ALJ Lilo D. Pomerleau read the record and joined in writing the PFD. Number running began on June 26, 2012, and Staff returned the final numbers to the ALJs on July 3, 2012. The parties requested that the ALJs submit their PFD so the Commission could consider the matter at its July 27, 2012, open meeting.

The following is a list of the parties who participated in the hearing and their counsel:

PARTIES	REPRESENTATIVES
ETI	Steven H. Neinast, Casey Wren, and John F. Williams[2]
Cities	Daniel J. Lawton, Stephen Mack, and Molly Mayhall
TIEC	Rex. D. VanMiddlesworth, Meghan Griffiths, and James Nortey
State of Texas	Susan Kelley
OPC	Sara J. Ferris
DOE	Steven A. Porter

[2] Several other attorneys appeared on behalf of ETI. The ALJs listed only the three attorneys who appeared throughout the hearing.

PARTIES	REPRESENTATIVES
Kroger	Kurt J. Boehm
Wal-Mart	Rick D. Chamberlain
Staff	Scott Smyth, Joseph Younger, Jacob J. Lawler, and Jason Haas

IV. EXECUTIVE SUMMARY

ETI proposed an overall increase of approximately $104.8 million. The ALJs recommend an overall rate increase for ETI of $16.4 million, as shown on the schedules attached to this PFD. With respect to ETI's request to reconcile fuel and purchased power costs during the Reconciliation Period, the ALJs recommend approval without change. Attachment A contains the schedules provided by Commission Staff reflecting the ALJs' recommendations. On issues of particular significance, the ALJs' recommendations are set forth below.

A. Rate Base

1. Capital Investment

ETI's capital additions closed to plant in service between July 1, 2009, and June 30, 2011, were prudently incurred and are used and useful in providing service to ETI's customers.

2. Hurricane Rita Regulatory Asset

The appropriate calculation of the Hurricane Rita regulatory asset should begin with the amount claimed by ETI in Docket No. 37744,[3] less amortization accruals to the end of the Test Year in the present case, and less the amount of additional insurance proceeds received by ETI after the conclusion of Docket No. 37744. This produces a remaining balance of $15,175,563, which should remain in rate base as a regulatory asset, applying a five-year amortization rate that commenced August 15, 2010. Further, the Hurricane Rita regulatory asset should not be moved to the storm insurance reserve.

[3] *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 37744 (Dec. 13, 2010).

3. Prepaid Pension Asset Balance

The construction work in progress (CWIP)-related portion of ETI's pension asset ($25,311,236 out of the total asset) should be excluded from the asset, but accrue allowance for funds used during construction.

4. FIN 48 Tax Adjustment

The Commission should find that $4,621,778 (representing ETI's full FIN 48 Liability of $5,916,461 less the $1,294,683 cash deposit ETI has made with the Internal Revenue Service (IRS) for the FIN 48 Liability) should be added to ETI's ADFIT and thus be used to reduce ETI's rate base.

5. Cash Working Capital

The ALJs recommend no changes to ETI's cash working capital.

6. Self-Insurance Storm Reserve

The Commission should approve ETI's Test Year-end storm reserve balance of negative $59,799,744.

7. Coal Inventory

The full value of ETI's coal inventory was reasonable and should be included in rate base.

8. Spindletop Gas Storage Facility

The Spindletop Gas Storage Facility (Spindletop Facility) is a used and useful facility providing reliability and swing flexibility to ETI's customers at a reasonable price and should be included in rate base.

9. Short Term Assets

The ALJs recommend Staff's proposal to include the following amounts in rate base: prepayments at $8,134,351 ($916,313 more than ETI's request); materials and supplies at $29,285,421 ($32,847 more than ETI's request); and fuel inventory at $52,693,485 ($1,066,490 less than ETI's request).

10. Acquisition Adjustment

The $1,127,778 incurred by ETI in internal acquisition costs associated with the purchase of the Spindletop Facility was reasonable, necessary, properly incurred, and should be included in rate base.

11. Capitalized Incentive Compensation

The Test Year for ETI's prior ratemaking proceeding ended on June 30, 2009. The reasonableness of ETI's capital costs (including capitalized incentive compensation) was dealt with by the Commission in that proceeding and is not at issue here. Thus, exclusion of capitalized incentive compensation that is financially-based can only be made for incentive costs that ETI capitalized during the period from July 1, 2009 (the end of the prior Test Year) through June 30, 2010 (the commencement of the current Test Year).

B. Rate of Return and Capital Structure

The ALJs recommend a return on equity (ROE) of 9.80 percent; a cost of debt of 6.74 percent; a capital structure comprised of 50.08 percent debt and 49.92 percent common equity; and an overall rate of return of 8.27 percent. This is a downward adjustment to ETI's request for a 10.60 percent ROE, and no change to ETI's 6.74 percent cost of debt and 50.08/49.92 capital structure. It compares to Staff's proposed 9.60 percent ROE; OPC's proposed 9.30 percent ROE; TIEC's proposed 9.50 percent ROE; Cities' proposed 9.50 percent ROE; and State Agencies' proposed 9.30 percent ROE. No party opposed ETI's proposed 6.74 percent cost of debt or its proposed 50.08/49.92 capital structure.

C. Cost of Service

1. Purchased Power Capacity Expense

ETI's purchased power capacity costs should be set at the amount of the Company's Test Year level, which is $245,432,884.

2. Transmission Equalization (MSS-2) Expense

ETI should recover only the amount of expenses under Schedule MSS-2 of the Entergy System Agreement it paid in the Test Year, $1,753,797.

3. Depreciation Expense

The interim retirements methodology should not be adopted. The values proposed by ETI should be adopted except for the following:

Service Lives:
Account 364-40 R1.
Account 368-33 L0.5.

Net Salvage:
Production Plant- negative 5 percent.
Account 354-negative 5 percent
Account 361-negative 5 percent.
Account 362-negative 10 percent.
Account 368-negative 5 percent.
Account 369.1-negative 10 percent.
Account 369.2-negative 10 percent.

4. Labor Costs

- ***Payroll and Related Adjustments***

The Commission should accept: (1) the payroll adjustments proposed in the ETI application; and (2) the further payroll adjustments proposed by Staff as corrected by ETI.

➢ ***Incentive Compensation***

ETI should not be entitled to recover its financially based incentive compensation costs. Thus, the ALJs recommend removing $6,196,037 from ETI's requested operation and maintenance (O&M) expenses. Additionally, an additional reduction should be made to account for the FICA taxes that ETI would have paid as a result of those costs.

➢ ***Compensation and Benefit Levels***

ETI met its burden to prove the reasonableness of its base pay and incentive package costs. It is reasonable to view market price for these categories of costs as lying within a range of +/- 10 percent of median, rather than being a single point along a spectrum. As to both base pay and the incentive package, ETI has proven that its costs fall within such an acceptable range. Accordingly, the ALJs recommend rejecting the adjustments sought by Cities.

➢ ***Nonqualified Executive Retirement Benefits***

The ALJs recommend an adjustment to remove $2,114,931, representing the full costs associated with ETI's non-qualified executive retirement benefits.

➢ ***Employee Relocation Costs***

The Commission should allow ETI's relocation expenses.

➢ ***Executive Perquisites***

The ALJs recommend an adjustment to remove $40,620, representing the full cost of ETI's executive perquisite costs.

5. Interest on Customer Deposits

The ALJs recommend using the active customer deposits amount of $35,872,476 and the 2012 interest rate, which produces a recommended interest expense of $43,047 ($35,872,476 multiplied by .12 percent).

6. Property (Ad Valorem) Tax Expense

ETI's property tax burden should be adjusted upward by applying the effective tax rate of 0.007435784 for the calendar year 2011 to the final, adopted Test Year-end plant in service value for ETI.

7. Advertising, Dues, and Contributions

The ALJs recommend an adjustment to remove $12,800 from ETI's costs of advertising, dues and contributions.

8. Other Revenue Related Adjustments

These amounts were determined through number running and are reflected in Attachment A.

9. Federal Income Tax

The Commission should adopt ETI's proposal on federal income taxes.

10. River Bend Decommissioning Expense

ETI's annual decommissioning revenue requirement should reflect the most current calculation of $1,126,000. Therefore, an adjustment of $893,000 to the *pro forma* cost of service is needed to reflect the difference between the requested level for decommissioning costs of $2,019,000 and the recommended level of $1,126,000.

11. Self-Insurance Storm Reserve Expense

The Commission should approve a total annual accrual of $8,270,000, comprised of an annual accrual of $4,400,000 to provide for average annual expected storm losses, plus an annual accrual of $3,870,000 for 20 years to restore the reserve from its current deficit. The ALJs recommend approval of ETI's proposed target reserve of $17,595,000. The Commission should require ETI to continue recording its annual accrual until modified by future Commission orders.

12. Spindletop Gas Storage Facility

The ALJs recommend inclusion of the costs of operating the Spindletop Facility as requested by ETI.

D. Affiliate Transactions

ETI agreed to remove the following affiliate transactions from its request, which the ALJs recommend be approved: (1) Project F3PPCASHCT (Contractual Alternative/Cashpo) in the amount of $2,553; (2) Project F3PCSPETEI (Entergy-Tulane Energy Institute) in the amount of $14,288; and (3) Project F5PPKATRPT (Storm Cost Processing & Review) in the amount of $929. Except as noted below, all remaining affiliate transactions should be approved. The ALJs recommend that the following affiliate transactions not be included:

- $356,151 (which figure includes the $112,531 agreed to by ETI) of costs associated with Projects F5PCZUBENQ (Non-Qualified Post Retirement) and F5PPZNQBDU (Non Qual Pension/Benf Dom Utl);
- $10,279 of costs associated with Project F3PPFXERSP (Evaluated Receipts Settlement);
- $19,714 of costs associated with Project F3PPEASTIN (Willard Eastin *et al*); and
- $171,032 of costs associated with Project F3PPE9981S (Integrated Energy Management for ESI).

E. Jurisdictional Cost Allocation

The ALJs recommend the use of 12 Coincident Peak (12CP) to allocate capacity-related production costs between the retail and wholesale jurisdictions.

F. Class Cost Allocation

1. Renewable Energy Credit Rider

The Commission should deny ETI's request to institute a renewable energy credit rider, and the Test Year expense of $623,303 should be used for setting rates in this case. Finally, the Renewable Portfolio Standard Calculation Opt-Out Credit Rider should be maintained, with an adjustment to the credit rates to reflect the Test Year data used to set ETI's base rates.

2. Class Cost Allocation

The parties generally agreed that ETI's cost-of-service study comported with accepted industry practices, but some parties had issues with specific items discussed below.

(a) Municipal Franchise Fees

Municipal franchise fees should be allocated on the basis of in-city kilowatt-hour (kWh) sales, without an adjustment for the municipal franchise fee rate in the municipality in which a given kWh sale occurred. The ALJs recommend adoption of ETI's proposal to collect costs from all customers taking service from the system.

(b) Miscellaneous Gross Receipts Tax

Similar to municipal franchise fees, miscellaneous gross receipts taxes should be allocated to the rate classes according to ETI's cost of service study.

(c) Capacity-Related Production Costs

The ALJs recommend the use of Average and Excess 4 Coincident Peak (A&E 4CP) to allocate capacity-related production costs, as proposed by ETI. The ALJs do not find sufficient support to allocate the reserve equalization payments differently than other capacity-related production costs.

(d) Transmission Costs

ETI's proposed methodology for allocation of transmission costs should be approved. A&E 4CP is a well-accepted method for allocating such costs.

3. Revenue Allocation

Revenue allocation in this case should be based on each class's cost of service and consistent with the ALJs' recommendations in the PFD that impact revenue allocation.

4. Rate Design

(a) Lighting and Traffic Signal Schedules

ETI should be directed to perform a light emitting diode (LED) lighting cost study before significant changes are made to its lighting rates. The ALJs further recommend that ETI conduct this study before filing its next rate case and provide the results of any completed study to Cities and interested parties. The study should include detailed information regarding differences in the cost of serving LED and non-LED lighting customers, if ETI currently has LED lighting customers taking service. ETI should modify the applicable tariffs to eliminate its fee for any replacement of a functioning light with a lower-wattage bulb.

(b) Demand Ratchet

ETI's proposed Large Industrial Power Service (LIPS) tariff should be amended to include the language proposed by DOE witness Etheridge.

(c) Large Industrial Power Service

The ALJs recommend the adoption of a \$630 customer charge for this customer class, a slight decrease in the LIPS energy charges, and an increase in the demand charges from current rates for this class, as proposed by Staff witness Abbott.

(d) Schedulable Intermittent Pumping Service

The Commission should adopt the Schedulable Intermittent Pumping Service rider proposed by DOE witness Etheridge.

(e) Standby Maintenance Service

The Commission should adopt the changes to Schedule SMS recommended by TIEC, with the exception of a $6,000 customer charge. Consistent with the ALJs' recommendation that a new LIPS charge of $630 is reasonable, the Standby Maintenance Service (SMS) charge should be limited to $630 and not apply if a Schedule SMS customer also purchased supplementary power under another applicable rate.

(f) Additional Facilities Charge

Schedule AFC should be changed in accordance with TIEC's recommendations and those recommended numbers should be reduced in proportion to any authorized reduction in ETI's proposed rate of return, O&M expense, and property tax expense.

(g) Large General Service

Schedule LGS should be amended as proposed by Kroger. Schedule LGS also has a demand ratchet, and the ALJs' recommendation for the elimination of ETI's LIPS demand ratchet is applicable to this class

(h) General Service

The Commission should adopt the decrease in the Schedule GS customer charge to $39.91 from the current (and Company proposed) rate of $41.09, as well as Staff's recommended decrease in energy charges. Schedule GS also has a demand ratchet, and the ALJs' recommendation for the elimination of ETI's LIPS demand ratchet is applicable to this class.

(i) Residential Service

ETI's declining block winter rates provide a disincentive to energy efficiency. The ALJs recommend an initial 20 percent reduction, followed by 20 percent subsequent reductions of the differential in the next three rate cases unless ETI provides sufficient evidence that such changes are unjust and unreasonable.

G. MISO Transition

The Commission should deny ETI's request for deferred accounting of its MISO transition expenses to be incurred on or after January 1, 2011. However, the Commission should authorize ETI to include $2.4 million of MISO transition expense in base rates set in the present case, based on a five-year amortization of $12 million in total projected expenses. Further, the Commission should authorize ETI to include in base rates $52,800 in MISO transition expenses for the 2010 portion of the Test Year expenses, plus $2.4 million for the post Test Year adjustment, for a total of $2,452,800.

V. RATE BASE [Germane to Preliminary Order Issue Nos. 4, 10, and 16]

A. Capital Investment [Germane to Preliminary Order Issue No. 17]

ETI presented for review $408,078,600 in capital additions closed to plant in service between July 1, 2009, and June 30, 2011; that is, from the end of the test year in the Company's last base rate case, which was Docket No. 37744, through the Test Year presented in this case. The capital additions were detailed in the testimony and exhibits of the following Company witnesses: Garrison (Generation), McCulla (Transmission), Corkran (Distribution), Stokes (Customer Service), Brown (Information Technology), Plauche (Administrative), Cicio (System Planning and Operations), Hunter (Supply Chain), May (Regulatory), and Sloan (Legal).[4] The evidence shows that these capital additions were prudently incurred and are used and useful in providing service to ETI's

[4] ETI Ex. 27 (Garrison Direct) at 20-28 and WWG-4; ETI Ex. 32 (McCulla Direct) at 64-92 and MFM-16; ETI Ex. 25 (Corkran Direct) at 78-108 and SBC-3; ETI Ex. 37A (Roman Direct, adopted by Stokes) at 121-125 and AFR-5; ETI Ex. 24 (Brown Direct) at 29-37 and JFB-3; ETI Ex. 20 (Plauche Direct) at 37-44 and TCP-11; ETI Ex. 39 (Cicio Direct) at 71-75 and PJC-6; ETI Ex. 16 (Hunter Direct) at 34-38 and JMH-7; ETI Ex. 7 (May Direct) at 53-54 and PRM-3; and ETI Ex. 38 (Sloan Direct) at 37-43 and RDS-4.

customers. No party challenged any of the capital additions or the costs thereof, and the ALJs find no reason to do so either.

B. Hurricane Rita Regulatory Asset

Hurricane Rita struck the upper Texas coast in September 2005, causing extensive property damage. In 2006, the Texas Legislature enacted PURA Chapter 39 to authorize electric utilities such as ETI to securitize the recovery of their reconstruction costs incurred as a result of Hurricane Rita. Under the statute, the amount of reconstruction costs to be securitized had to be reduced by the insurance proceeds and government grants received by a utility. If additional insurance or grant proceeds were received after the securitization order was approved, the Commission was required to take those amounts into account in the utility's next base rate case. This was provided in Section 39.459(c) of PURA:

> To the extent a utility subject to this subchapter receives insurance proceeds, governmental grants, or any other source of funding that compensates it for hurricane reconstruction costs, those amounts shall be used to reduce the utility's hurricane reconstruction costs recoverable from customers. If the timing of a utility's receipt of those amounts prevents their inclusion as a reduction to the hurricane reconstruction costs that are securitized, the commission shall take those amounts into account in:
>
> (1) the utility's next base rate proceeding; or
>
> (2) any proceeding in which the commission considers hurricane reconstruction costs.

Docket No. 32907 was the proceeding for ETI to determine the amount of Hurricane Rita reconstruction costs that it could securitize, net of any proceeds received from insurance or government grants.[5] In that case, ETI asserted that it incurred $393,236,384 in Hurricane Rita reconstruction costs for its Texas Retail jurisdiction. The parties reached a settlement in that case, which set ETI's hurricane reconstruction expenses eligible for securitization at $381,236,384. In addition, ETI estimated that it would receive $65,700,000 in future insurance proceeds that, pursuant to the settlement, was deducted from the amount to be securitized. The parties also agreed that after

[5] *Application of Entergy Gulf States, Inc. for Determination of Hurricane Reconstruction Costs*, Docket No. 32907 (Dec. 1, 2006).

ETI received all of its insurance payments, a true-up would occur to reflect the difference between the $65,700,000 credited and the amount actually received. The settlement agreement provided that if ETI received more insurance payments than estimated, the excess payments would be passed through to ratepayers in the form of a rider; however, the agreement did not address how an under-recovery by ETI would be handled. It turned out that ETI received only $46,013,904 in insurance proceeds,[6] leaving a $19,686,096 under-recovery by ETI, which the parties refer to as Overestimated Insurance Proceeds.[7]

Docket No. 37744 was ETI's next base rate case after Docket No. 32907. In Docket No. 37744, ETI requested recovery of the Overestimated Insurance Proceeds by establishing a regulatory asset of $19,686,096, plus accrued carrying costs, to be amortized over five years.[8] Docket No. 37744 also concluded by a black-box settlement, and neither the Stipulation and Settlement Agreement nor the Order entered by the Commission specifically addressed the proposed regulatory asset or any other recovery for Overestimated Insurance Proceeds.

In the present case, ETI has again sought approval of a regulatory asset to recover $26,229,627, for the balance of Overestimated Insurance Proceeds, plus carrying costs through June 30, 2011.[9] Cities objected to the amount of ETI's request. They argue that this issue was resolved in Docket No. 37744 and that ETI should have been amortizing the asset since the conclusion of that case. Staff also argues that the issue was resolved in Docket No. 37744 and requested that ETI's request be denied entirely; or, alternatively, that it should be considered partially amortized and accordingly reduced. ETI argues that the issue was not resolved in Docket No. 37744 and that it should be allowed a full recovery in the present case. Alternatively, ETI argues that Cities' proposed reduction was not calculated correctly.

Cities' expert accounting witness, Mark Garrett, testified that ETI should have been amortizing the balance of Overestimated Insurance Proceeds since the effective date of rates set in

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6 *See* Docket No. 32907, Final Order at FoF 27. Cities Ex. 2 (Garrett Direct) at Exhibit MG2.3.

7 $19,686,096 = 65,700,000 - $46,013,904.

8 Cities Ex. 2 (Garrett Direct) at 11.

9 Schedule P Cost of Service Workpapers, Vol. 2, ETI Ex. 3 at AJ 15, page 15.3.

Docket No. 37744. In addition, he argues that ETI should not have continued to accrue interest on the balance that was added into rate base in that docket, because it would have then earned a rate of return. Therefore, Mr. Garrett's adjustment started with the balance of $25,278,210 that ETI requested in Docket No. 37744. He reduced that balance by $9,479,329 for amortization between the date rates went into effect in Docket No. 37744 and the date that rates will go into effect in the current case (22.5 months). Mr. Garrett further reduced the remaining balance by $5,678,960 to account for additional insurance proceeds received by ETI after Docket No. 37744. By Mr. Garrett's calculations, this left a remaining balance of Overestimated Insurance Proceeds of $11,071,338.[10] Both Mr. Garrett and Cities witness Jacob Pous also recommended that this remaining balance not be carried as a regulatory asset but, instead, be moved to the storm insurance reserve for recovery.[11] In their view, this would ensure that the remaining balance would be properly recovered.

In response to ETI's argument that the Hurricane Rita Regulatory Asset was not resolved in Docket No. 37744, Cities stress that Docket No. 37744 settled as a "black box settlement." In Cities' opinion, such a settlement should not be interpreted as changing the status quo unless expressly stated in the settlement agreement or final order. Cities contend that the status quo in Docket No. 37744 was that ETI was authorized to recover its Over Estimated Insurance Proceeds, because recovery was authorized by PURA § 39.459(c); recovery had been previously approved in Docket No. 32907; and no party objected to its recovery in Docket No. 37744. Therefore, Cities state, the final order in Docket No. 37744 should be interpreted as authorizing ETI's requested recovery of the Hurricane Rita Regulatory asset in the rates set in that docket.[12]

Cities also disagree with ETI's alternative argument that Mr. Garrett improperly calculated the remaining balance of the asset by deducting an amount for insurance proceeds ETI received after Docket No. 37744 concluded. Cities state that Mr. Garrett's adjustment was correct because it began with the balance requested in Docket No. 37744, before the additional insurance proceeds were received. In other words, Mr. Garret did not start with the balance claimed by ETI in the present

[10] Cities Ex. 2 (Garrett Direct) at Exhibit MG2.3.

[11] *Id*. (Garrett Direct) at 12; Cities Ex. 5 (Pous Direct) at 64.

[12] Cities Reply Brief at 10-14.

case,[13] so he correctly applied the amount received after Docket No. 37744 to reduce the balance claimed in that docket.[14] According to Cities, Mr. Garrett began with the prior balance to properly reflect that no carrying charges would accrue on the balance after it was included in rate base and recovered a return through rates.[15] Cities also dispute ETI's argument that Mr. Garrett should not have accounted for amortization occurring between the Test Year and the Rate Year as an "invalid post-test year adjustment."[16] In Cities' view, this was a valid known and measureable change that should be taken into account.[17]

Staff recommends that the Hurricane Rita Regulatory Asset be removed from rate base entirely. Staff witness Anna Givens stated that it is reasonable to assume that this asset was included as part of the settlement in Docket No. 37744. Accordingly, she stated that it is not appropriate for ETI to request recovery of the same asset in the present docket. Therefore, Ms. Givens recommended removal of the entire requested $26,229,627 Hurricane Rita regulatory asset from ETI's rate base.[18]

Alternatively, Ms. Givens proposed that the Commission allow ETI a regulatory asset of $17,486,418, to be amortized over 40 months. Ms. Givens noted that higher rates from Docket No. 37744 first went into effect on August 15, 2010;[19] therefore, at least one-third of the regulatory asset should have been amortized by the conclusion of the present case. Using ETI's updated hurricane regulatory asset request of $26,229,627, Ms. Givens recommended a decrease of one-third to ETI's request. This would equal an $8,743,209 reduction, resulting in her recommended regulatory asset of $17,486,418 ($26,229,627 - $8,743,209). Ms. Givens also recommended that the

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[13] Cities Initial Brief at 8.

[14] Cities Ex. 2B (Garrett Direct), Exhibit MG-2.3.

[15] Docket No. 32907, Final Order at FoF 28.

[16] ETI's Initial Brief at 7.

[17] Cities' Reply Brief at 10-14.

[18] Staff Ex. 1 (Givens Direct) at 32-34.

[19] Docket No. 37744, Order, FoF 16 (Dec. 13, 2010).

amortization period be decreased from 60 months to 40 months, which is the time remaining on ETI's original Docket No. 37744 request.[20]

ETI disagrees with Cities and Staff, and it argues that its total requested Hurricane Rita regulatory asset should be included in rate base in this case. First, it notes that no instruction in the Stipulation and Settlement Agreement filed in Docket No. 37744 required ETI to begin amortizing the asset or otherwise directed the treatment of the asset. Likewise, no Finding of Fact or Conclusion of Law in the agreed order entered in Docket No. 37744 authorized the proposed treatment of the asset. In contrast, ETI notes, the settlement in Docket No. 32907 does specifically address the treatment of this asset, and it argues that its request to include the full Hurricane Rita regulatory asset in rate base in the present case is consistent with that settlement. In ETI's opinion, it has not previously been authorized to establish the regulatory asset, it has not amortized it, and the full amount should be included in rate base in this case.[21]

Alternatively, if Cities' proposed amortization is accepted, ETI argues that Mr. Garrett's calculations were wrong. First, ETI states, Mr. Garrett incorrectly assumed that the $26,229,627 Hurricane Rita regulatory asset requested in this case did not account for the $5,678,960 of insurance proceeds that ETI received after Docket No. 37744. According to ETI, the $5,678,960 was accounted for, as shown on WP/P AJ 15.3. Therefore, ETI states, Mr. Garrett's adjustment for this $5.6 million would remove this amount from the asset a second time.[22] Second, ETI argues that Mr. Garrett erred by amortizing the asset by 22.5 months. Mr. Garrett calculated the amortization period from the time rates went into effect after Docket No. 37744 (August 15, 2010) through the time revised rates would go into effect in this docket (June 30, 2012). ETI states that Mr. Garrett made an invalid post-test year adjustment because post-test year adjustments for rate base items are limited to plant additions recorded in FERC Accounts 101 or 102. In contrast, regulatory assets, like

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[20] Staff Ex. 1 (Givens Direct) at 34. Ms. Givens noted that amount recommended in Docket No. 37744 was $25,278,000, which is $951,627 less than the amount requested in the current proceeding. However, she stated that this does not affect her recommendation, because by the time the hearing on the merits concluded, at least another two months of amortization expense under the existing rates would be collected by the ETI and should adequately compensate it for the difference. Staff Ex. 1 (Givens Direct) at 35.

[21] ETI Ex. 46 (Considine Rebuttal) at 19-24; ETI Initial Brief at 5-6.

[22] ETI Ex. 46 (Considine Rebuttal) at 21-22; ETI Initial Brief at 7.

the Hurricane Rita regulatory asset, are recorded in Account 182.3. Therefore, in ETI's opinion, if it was required to amortize this regulatory asset, it would be appropriate to amortize it for only 10.5 months, to the end of the Test Year (August 15, 2010, through June 30, 2011). These two corrections would adjust Mr. Garrett's proposed asset balance from $10,714,557 to $21,805,940.[23]

ETI also disagrees with Mr. Pous' recommendation that the regulatory asset be removed from rate base and placed in the storm reserve, to be amortized over 20 years. In ETI's opinion, this approach would defeat the purpose of securitization, which is to provide ETI with cost recovery in an expedited manner.[24]

Finally, ETI argues that Ms. Givens' analysis was flawed. It reiterated that no provision in the Stipulation and Settlement Agreement or the final order filed in Docket No. 37744 directed the treatment of the regulatory asset or stated that ETI would begin amortizing the asset. Further, ETI stresses that it never sought recovery of the entire asset all at once in Docket No. 37744. Instead, ETI requests recovery over a period of years through amortization. Thus, according to ETI, even if Ms. Givens' argument were accepted, the entire asset should not be disallowed.[25]

This issue is a close call because the black-box settlement agreement and final order in Docket No. 37744 did not expressly state how the Hurricane Rita regulatory asset issue was resolved. The following factors support finding that the Hurricane Rita regulatory asset issue was resolved in Docket No. 37744:

- the settlement agreement and final order in Docket No. 32907 expressly provided that the difference between the amount of ETI's estimated insurance proceeds and the amount actually received by ETI would be trued up after ETI received the proceeds;

- PURA § 39.459(c) provides that if the timing of a utility's receipt of insurance proceeds prevented their inclusion as a reduction to the securitized costs, the Commission "shall take those amounts into account . . . *in the utility's next base rate proceeding*;"

[23] ETI Ex. 46 (Considine Rebuttal) at 22; ETI Initial Brief at 7-8.

[24] ETI Initial Brief at 8.

[25] ETI Ex. 46 (Considine Rebuttal) at 21; *Id.* at 8-9.

- Docket No. 37744 was ETI's next base rate proceeding;
- in Docket No. 37744, ETI requested a true-up concerning the insurance proceeds, and it requested that a regulatory asset be established for the deficit and amortized over five years;
- in Docket No. 37744, no party objected to ETI's proposed regulatory asset or amortization;
- the stipulation and settlement agreement entered by the parties in Docket No. 37744 stated that the parties resolved all issues, except for ETI's Competitive Generation Service (CGS) proposal; and
- neither the stipulation and settlement agreement nor the Order entered in Docket No. 37744 specifically disapproved, excluded, or deferred consideration ETI's proposed regulatory asset, although they did specifically exclude or disapprove other items, such as ETI's CGS proposal and various proposed riders.

On the other hand, some factors support a finding that the Hurricane Rita regulatory asset issue was not resolved in Docket No. 37744. The stipulation and settlement agreement and the Order entered in Docket No. 37744 did not expressly approve ETI's proposed regulatory asset, although certain other items were expressly approved, such as River Bend Nuclear Generating Station Unit No. 1 (River Bend) decommissioning costs, depreciation rates, and other items. Also, utilities are typically not allowed to create regulatory assets without express approval of the Commission.

Thus, the difficulty with this issue is the nature of the black-box settlement of Docket No. 37744. In the settlement, the parties agreed to an increase in base rate revenues of $59 million effective August 15, 2010, with an additional increase in base rate revenues effective May 2, 2011. However, there was no explanation on how this increase was determined, and there was no specific agreement or finding on the amount of ETI's rate base or its reasonable and necessary cost of service. In that case, there was no objection to ETI's proposed Hurricane Rita regulatory asset, it was authorized by the prior settlement in Docket No. 32907, and the Commission was directed by PURA § 39.459(c) to take into account ETI's insurance proceeds related to the Hurricane Rita securitized costs in ETI's next rate case, which was Docket No. 37744. Moreover, when there is uncertainty whether an *undisputed issue* was deferred for future consideration or was included within the rates set in a black-box settlement, the burden should be on the utility to establish that the issue was deferred for future consideration. When all the evidence and factors are considered, the ALJs find that that ETI's proposed Hurricane Rita regulatory asset should be considered as having been approved in Docket No. 37744, and ETI should have amortized the asset since August 15, 2010, the effective date of rates approved in that docket.

The ALJs also find that none of the amortization calculations proposed by the parties were entirely correct. ETI's proposal to start with its requested $26,229,627 was flawed because it included carrying costs from August 15, 2010, when the asset should have been included in rate base, to June 30, 2011, the end of the Test Year in the present case. During that period, the asset would have earned a rate of return as part of rate base, and accrual of carrying costs should have ceased. Therefore, it would be more accurate to begin amortizing the Hurricane Rita regulatory asset by using the balance requested by ETI in Docket No. 37744. That amount, according to Mr. Garrett, was $25,278,210. However, the amortization calculation should not extend beyond the end of the Test Year in the present case (June 30, 2011), as proposed by Cities and Staff. P.U.C. SUBST. R. 25.231(c)(2)(F)(ii) provides for post-test-year reductions to rate base, and the recommendation for a post-test-year adjustment to the Hurricane Rita regulatory asset does not fall within the scope of that rule. The balance remaining after amortization to the end of the Test Year should be further reduced by $5,678,960 to account for additional insurance proceeds received by ETI after Docket No. 37744 concluded but before the end of the Test Year in the present case. ETI argues that this reduction was already included in its request. However, as discussed above, the appropriate calculation should begin with the balance of the asset at the conclusion of Docket No. 37744, not the balance requested by ETI in the present case. The balance of the asset at the conclusion of Docket No. 37744 did not account for the additional insurance proceeds paid to ETI afterwards, so it should be deducted now. In summary, the ALJs find that the appropriate amount of the Hurricane Rita regulatory asset to be included in rate base in this case should be calculated as follows:

Beginning balance at conclusion of Docket No. 37744 (original balance + carrying charges)	$25,278,210
Less amortization for period 8/15/10 to 6/30/11 = 10.5 months / 60 months = 17.5%	- $4,423,687
Less additional insurance proceeds received	- $5,678,960

Remaining balance of Hurricane Rita regulatory asset	$15,175,563

Finally, the ALJs recommend that the Commission not adopt the recommendation of Cities to move the Hurricane Rita regulatory asset to the storm insurance reserve for recovery. As noted by ETI, one purpose of enactment of PURA Chapter 39 was to allow expedited recovery of costs resulting from Hurricane Rita storm damage. Moving the regulatory asset to the storm insurance reserve would defeat that purpose and negate the five-year amortization plan the parties agreed to in Docket No. 37744.

In summary, the ALJs find that ETI's proposed Hurricane Rita regulatory asset was an issue resolved by the black-box settlement in Docket No. 37744. Therefore, ETI should have included the asset in rate base at the conclusion of that docket and should have begun amortizing it over a period of five years. The accrual of carrying charges should have ceased when Docket No. 37744 concluded, because the asset would have then begun earning a rate of return as part of rate base. The appropriate calculation of the asset should begin with the amount claimed by ETI in Docket No. 37744, less amortization accruals to the end of the Test Year in the present case, and less the amount of additional insurance proceeds received by ETI after the conclusion of Docket No. 37744. This produces a remaining balance of $15,175,563, which should remain in rate base as a regulatory asset, applying a five-year amortization rate that commenced August 15, 2010. Further, the Hurricane Rita regulatory asset should not be moved to the storm insurance reserve.

C. Prepaid Pension Asset Balance

ETI included in rate base an item titled Unfunded Pension in the amount of $55,973,545.[26] The amount requested in this account represents the accumulated difference between the Statement of Financial Accounting Standards (SFAS) No. 87 calculated pension costs each year and the actual contributions made by the Company to the pension fund.[27] It is a debit balance, meaning that the

[26] ETI Ex. 3, Sched. B-1, Line 10.

[27] Cities Ex. 2 (Garrett Direct) at 7.

Company has contributed roughly $56 million more to its pension fund than the minimum required by SFAS 87.[28] Other than Cities, no party opposes ETI's request to include this item in rate base.

Cities argue that ETI ought not be entitled to include this amount in rate base because it represents amounts the ETI overpaid to its pension, resulting in little to no benefit to ratepayers. Cities witness Mark Garrett pointed out that ETI earned only 1.37 percent on its pension assets over the past five years, while it is seeking a rate of return of more than 11 percent. Thus, he argues, if the asset were included in rate base, ratepayers would pay a substantial premium for the slight pension cost savings ETI's excess contributions may have achieved.[29]

Cities argue that the entire prepaid pension asset should be removed from rate base because ETI has not justified its inclusion. This would reduce *pro forma* rate base by $36,382,803, which is the net amount of the prepaid balance less accumulated deferred income tax ($55,973,545 – $19,590,740 = $36,382,803). At the same time, Cities would increase operating expense by $498,284, to provide a 1.37 percent return on the net balance of ETI's prepaid pension asset balance.[30]

Alternatively, Cities contend that the Commission should treat the pension assets in the same manner as the approach adopted by the Commission in Docket No. 33309.[31] In that docket, the Commission allowed a pension prepayment asset, less accrued deferred federal income taxes (ADFIT) and less the portion of the asset that is capitalized to CWIP, to be included in rate base. As to the excluded portion, the Commission allowed the accrual of an allowance for funds used during construction (AFUDC). Thus, Cities contend, if the Commission opts for this approach, it should allow ETI's pension prepayment asset, less ADFIT, to be included in rate base, but excluding

[28] ETI Initial Brief at 10; Cities Ex. 2 (Garrett Direct) at 8.

[29] Cities Ex. 2 (Garrett Direct) at 8-9.

[30] *Id.* at 10, MG-2.2; Cities Initial Brief at 10.

[31] *Remand of Docket No. 33309 (Application of AEP Texas Central Company for Authority to Change Rates)*, Docket No. 38772, Order on Remand at FoF 15A (Jan. 30, 2011).

$25,311,236 for the portion of the prepaid pension balance associated with CWIP, and allow AFUDC to accrue on the excluded balance.[32]

ETI responds first by disputing Mr. Garrett's contention that it has unreasonably overpaid into its pension fund. It contends it has made contributions to the pension fund in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, and that the contributions were within the allowable range of contributions deductible for tax purposes. ETI also was guided in its required pension contributions by the Pension Protection Act of 2006 rules, effective beginning with the 2008 plan year.[33]

ETI next disputes Cities' contention that the earnings associated with ETI's pension contributions provide insufficient benefits to justify inclusion of the asset in rate base. ETI points out that ratepayer benefits are not just limited to the level provided by the actual pension fund earnings on investment. Rather, under FAS 87, pension costs included in the cost of service for ratemaking purposes are intended to include the *expected* rate of return on assets. Thus, ETI argues that the expected long-term rate of return on ETI's assets is 8.5 percent, not the actual earnings as suggested by Mr. Garrett.[34]

On behalf of ETI, Mr. Considine testified that the pension balance is no different than any other prepayments made by the Company, which are included in rate base and earn a full return on rate base. Furthermore, the Company would be allowed to earn a full return on rate base had the Company invested these same dollars in Plant in Service, but the Company in this case used funds to contribute to a still under-funded pension plan and at the same time provided a timely reduction to formerly FAS 87 annual pension cost, thereby immediately benefitting ratepayers.[35] Therefore, ETI argues it is clearly investor-supplied capital and accordingly should earn the Company's requested return on rate base.

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[32] Cities Initial Brief at 8-9; Cities Ex. 2 (Garret Direct) at 12.

[33] ETI Ex. 46 (Considine Rebuttal) at 22.

[34] *Id.*

[35] *Id.* at 23-24.

ETI acknowledged the approach to this issue taken by the Commission in Docket No. 33309, but failed to explain why it is distinguishable from the present case.[36]

The ALJs conclude that the approach taken by the Commission in Docket No. 33309 was sound and should be applied in the present case. Neither party adequately explained why the circumstances of the present case are distinguishable. Thus, the ALJs recommend that the CWIP-related portion of ETI's pension asset ($25,311,236 out of the total asset) should be excluded from the asset, but accrue allowance for funds used during construction.

D. FIN 48 Tax Adjustment

The Financial Accounting Standards Board (FASB) is the body that establishes the rules that constitute generally accepted accounting principles (GAAP). FASB's Interpretation No. 48 (FIN 48) prescribes the way in which a company must analyze, quantify, and disclose the potential consequences of tax positions that the company has taken which are legally "uncertain." Pursuant to FIN 48, ETI and its independent auditors are required to evaluate each of its uncertain tax positions to determine, under the most objective, reasonable standards, which portion of each position will most likely ultimately have to be paid to taxing authorities if challenged by the authorities. FIN 48 requires that this portion be excluded from ADFIT for financial reporting purposes and accrue interest and, in some cases, penalties.[37]

ETI and its auditors periodically perform the FIN 48 analysis. In so doing, they have concluded that the Company has taken a number of uncertain tax positions that the Company expects to lose if challenged by the IRS. ETI concluded that these uncertain tax positions result in a total of $5,916,461 in tax dollars that the Company expects it will ultimately have to pay, with interest, to the IRS. As required by FIN 48, this amount is recorded on ETI's balance sheet as a tax liability.[38] In other words, ETI has, thus far, avoided paying to the IRS $5,916,461 in tax dollars (ETI's FIN 48

[36] ETI Initial Brief at 10-11.

[37] ETI Ex. 70 (Warren Rebuttal) at 9-12.

[38] ETI Ex. 64 (Roberts Rebuttal) at 4-7.

Liability) in reliance upon tax positions that the Company believes will not prevail in the event the positions are challenged, via an audit, by the IRS.

In preparing its application in this proceeding, ETI made an accounting adjustment to its Test Year numbers by not including the $5,916,461 in its ADFIT balance. This had the effect of reducing the Company's Test Year deferred tax balance and, therefore, increasing its rate base.[39]

Cities witness Mark Garrrett asserted that the deduction of $5,916,461 – representing ETI's FIN 48 Liability – should be added to ETI's ADFIT balance and thus be used to reduce the Company's rate base. Mr. Garrett pointed out that the Commission first considered this issue in a recent Oncor docket.[40] In that docket, the Commission decided to include FIN 48 liabilities in ADFIT because of the low likelihood that the IRS would actually audit and review the issue.[41] Mr. Garrett testified that this is a fair result because: (1) a utility with FIN 48 liabilities might never have its underlying uncertain tax positions audited by the IRS; and (2) even if the uncertain positions are audited by the IRS, the utility might prevail on them. In either case, the utility would never have to pay those tax amounts. Moreover, during the time when the uncertainty exists, the utility enjoys the use of cost-free capital (from the deferred taxes associated with the deductions) at its disposal.[42] Thus, Mr. Garrett recommends that ETI's ADFIT balance be increased by $5,916,461 to reinstate the FIN 48 Liability removed by the Company.[43]

ETI witnesses Rory Roberts and James Warren stated that the $5,916,461 should not be included in the Company's ADFIT balance. Mr. Roberts explained that, because the Company expects to lose on its uncertain tax positions, it expects that it will ultimately have to pay $5,916,461 in taxes to the IRS, plus interest. Accordingly, Mr. Garrett testified that the amount does not

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[39] *Id.* at 4.

[40] Cities Ex. 2 (Garrett Direct) at 5-7. *See also Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, Docket No. 35717, Order on Reh'g (Nov. 30, 2009).

[41] *Id.* at 18 FOF 59 ("The IRS may not audit or reverse Oncor's position as to the tax deductions identified as FIN 48 deductions and moved into the FIN 48 reserve.").

[42] Cities Ex. 2 (Garrett Direct) at 5-6.

[43] *Id.* at 7.

represent cost-free funds available to the Company and, as such, should not be included in the Company's ADFIT balance.[44]

Both the Cities and ETI agree that ETI's rate base "should reflect the actual amount of cost free capital in the ADFIT accounts at Test Year end."[45] However, ETI witness Mr. Warren testified that the FIN 48 Liability is not cost-free capital to the Company because the best available expert opinion in the record of this case is that ETI will "most likely" ultimately have to pay the money to the IRS, with interest.[46]

Moreover, Mr. Warren pointed out that, beginning with 2010 tax returns, a corporate taxpayer is required to complete and file a Schedule UTP, on which the taxpayer must specifically identify and describe its FIN 48 positions. Mr. Warren contended that, because ETI must now annually file a Schedule UTP, it is more likely that the IRS will audit the Company, thereby forcing it to pay the FIN 48 Liabilities, with interest.[47] This constitutes additional support for the notion that the FIN 48 Liability is not cost-free capital for the Company. Mr. Warren correctly points out that, in a recent CenterPoint Energy Houston Electric, LLC, (CenterPoint) rate case, the Commission specifically acknowledged that filing of a Schedule UTP makes it more likely that a company will be audited. In that case, the ALJs recommended that CenterPoint's FIN 48 Liability, totaling some $164 million, be added to CenterPoint's ADFIT, thereby reducing its rate base. The Commission adopted the recommendation. However, in light of its conclusion that the filing of a Schedule UTP increases the likelihood of an audit, the Commission authorized CenterPoint to establish a deferred tax account rider to enable it to recover any portion of its FIN 48 Liability that it might ultimately be forced to pay to the IRS, plus interest.[48] ETI does not necessarily oppose the use of a rider in this

[44] ETI Ex. 64 (Roberts Rebuttal) at 7.

[45] Cities Ex. 2 (Garrett Direct) at 6; see also ETI Ex. 70 (Warren Rebuttal) at 6-7.

[46] ETI Ex. 70 (Warren Rebuttal) at 17.

[47] *Id*. at 14, 20-21.

[48] ETI Ex. 70 (Warren Rebuttal) at 19-20. *See also Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Order on Reh'g at 3-4 (June 23, 2011).

case, but contends that it would be preferable to simply exclude ETI's FIN 48 Liability from its ADFIT balance, thereby increasing its rate base.[49]

In the alternative that the Commission rejects ETI's request to exclude the full amount of the FIN 48 Liability from the Company's ADFIT balance, ETI contends that at least any amount of cash deposit the Company has made with the IRS that is attributable to the FIN 48 Liability should be removed from the Company's ADFIT balance.[50] The Cities' witness, Mr. Garrett, agrees.[51] Staff also agrees, arguing that ETI should be required to increase its ADFIT balance by the amount of its FIN 48 Liability less the amount of any cash deposit attributable to the liability that ETI has made with the IRS.[52] ETI has made a cash deposit with the IRS in the amount of $1,294,683. This amount is associated with the Company's FIN 48 Liability.[53]

Consistent with prior Commission precedent from the Oncor and CenterPoint proceedings, the ALJs conclude that ETI's FIN 48 Liability should be included in the Company's ADFIT balance. There is, however, one caveat to this conclusion. The amount of the cash deposit made by ETI to the IRS which is attributable to the Company's FIN 48 Liability should not be included in the ADFIT balance. Therefore, the ALJs recommend that the Commission find that $4,621,778 (representing ETI's full FIN 48 Liability of $5,916,461 less the $1,294,683 cash deposit ETI has made with the IRS) should be added to ETI's ADFIT and thus be used to reduce ETI's rate base. No party expressly advocated the addition of a deferred tax account rider,[54] and the ALJs do not recommend one in this case.

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[49] ETI Initial Brief at 13; ETI Ex. 70 (Warren Rebuttal) at 20.

[50] ETI Ex. 64 (Roberts Rebuttal) at 8-9.

[51] Cities Ex. 2 (Garrett Direct) at 7 n. 4.

[52] Staff's Initial Brief at 11-12.

[53] ETI Ex. 64 (Roberts Rebuttal) at 8.

[54] Cities and Staff both point out that there is much less need for a deferred tax account rider in the present case than there was in the CenterPoint case, where CenterPoint had $164 million in FIN 48 liabilities. Cities Reply Brief at 18; Staff Reply Brief at 10.

E. Cash Working Capital

Rate base includes a reasonable allowance for cash working capital. Cash working capital represents the average amount of investor capital used to bridge the gap in time between when expenditures are made by ETI to provide services and when the corresponding revenues are received by ETI.[55] Generally, an increase in revenue lag days and/or a decrease in expense lead days will result in an increase to the amount of cash working capital included in the rate base. Conversely, a decrease in revenue lag days and/or an increase in expense lead days will reduce the cash working capital included in rate base. A properly prepared lead-lag study can result in either a positive cash working capital amount (and therefore an increase to the rate base) or a negative cash working capital amount (and a corresponding decrease to the rate base).

Pursuant to P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)(IV), ETI calculated its cash working capital allowance by performing a lead-lag study. ETI witness Jay Joyce prepared the lead-lag study for the Company. Based upon the study, ETI requests a cash working capital addition to its rate base of negative $2,013,921.[56]

Only Staff and Cities submitted evidence and argument relevant to the cash working capital requirement. Staff does not challenge the accuracy of the lead and lag days determined in Mr. Joyce's study. Instead, Staff witness Anna Givens recommends that the cash working capital calculation be updated to reflect the impacts of Staff's recommended adjustments to ETI's O&M costs and taxes.[57] ETI agrees that the final cash working capital amount should be updated to reflect the actual revenue requirements approved by the Commission in this case.[58]

Cities witness Jacob Pous asserts that Mr. Joyce's lead-lag study contains a number of errors which understate the negative cash working capital requirements of the Company. Mr. Pous asserts that the correct cash working capital amount for inclusion in ETI's rate base is negative $24,000,000

55 ETI Ex. 17 (Joyce Direct) at 4.

56 *Id.* at 20 and JJJ-3.

57 Staff Ex. 1 (Givens Direct) at 30-31.

58 ETI Ex. 54 (Joyce Rebuttal) at 37; ETI Initial Brief at 14.

(more than an order of magnitude increase of the negative amount).[59] Each of the major components of the lead-lag study, and Cities' criticisms of same, will be discussed in turn.

1. The Revenue Lag Component of the Lead-Lag Study

Mr. Pous raises a number of criticisms about the revenue lag component of Mr. Joyce's lead lag study. There are four parts to the revenue lag component: (1) the "service period lag," which consists of the roughly 15 days from the mid-point of the month in which service is provided to the end of that month; (2) the "billing lag," which represents the time between the date a customer's meter is read and the date a bill is issued to the customer; (3) the "collection lag," which represents the time between the issuance of the bill and the date the customer's payment is received; and (4) "receipt of funds lag," which measures the delay between ETI's receipt of payment and the bank's clearance of the payment.[60] When the four parts were combined together, Mr. Joyce identified ETI's revenue lag as 43.86 days.[61]

(a) Billing Lag

Mr. Joyce identified the billing lags (*i.e.*, the delay between when meters are read and bills are sent to customers) as ranging from 5.4 to 5.65 days, depending upon the customer class.[62] On behalf of the Cities, Mr. Pous asserted that this duration is too long. Mr. Pous complained that the billing lag in ETI's lead-lag study is longer than in studies from previous ratemaking proceedings involving ETI's predecessor, despite the fact that, in the interim between studies, ETI has invested substantially in electronic meter reading devices and computer systems that ought to shorten the lag time. According to Mr. Pous, in a previous proceeding, ETI's predecessor identified its billing lag as only 3.61 days.[63] Mr. Pous also pointed out that the Railroad Commission of Texas (RRC), recently adopted a 1-day billing lag for a large gas utility, Atmos Mid-Tex, due to the utility's use of modern electronic meter reading devices (the Atmos Mid-Tex RRC proceeding). Mr. Pous stated that the

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[59] Cities Ex. 5 (Pous Direct) at 72.

[60] ETI Ex. 17 (Joyce Direct) at 8-10.

[61] *Id.* at JJJ-3.

[62] Cities Ex. 5 (Pous Direct) at 74.

[63] *Id.*

billing lag identified by ETI would unjustly reward the Company for being inefficient in sending out its bills because customers should not be punished if the utility decides to manage its billing processing and payment system less efficiently. Thus, Mr. Pous recommended a schedule of different billing lags for different customer classes. For residential and commercial customers, Mr. Pous recommended a 1.46 day billing lag, based since ETI's predecessor claimed such a lag in a prior PUC docket (Docket No. 12852). For large industrial, public authority, and street lighting customers, Mr. Pous recommends a billing lag of 3.72 days. He calculated that the combined impact of these adjustments would result in a 41.10-day total revenue lag (as compared to Mr. Joyce's figure of 43.86 days). Mr. Pous then calculates that this shorter lag period results in an additional negative cash working capital of $11.4 million.[64]

ETI responds by pointing out that the 1.46-day billing lag suggested by Mr. Pous for residential and commercial customers was derived from a rate case by ETI's predecessor from 1993, whereas Mr. Joyce more properly relied on actual Test Year data. Mr. Joyce asserted that Mr. Pous, in effect, "cherry picked" the 1.46-day figure from one page of a 47-page study associated with the 1993 rate case, and that the remaining pages of the study have not been located and, therefore, cannot be evaluated. Thus, Mr. Joyce testified, "[i]t is unfair and unreasonable to use such an old document to attempt to support a position when reasonable, contemporaneous evidence exists."[65]

ETI argues that it is more appropriate in this case to rely upon ETI's actual residential and commercial billing practices, rather than to substitute artificial and arbitrary 1.46-day and 3.72-day periods derived from other sources. According to Mr. Joyce, it is unavoidably necessary, when conducting a lead-lag study, to take into account the actual amount of time employed by ETI in performing all of the activities in its billing-cycle-based meter reading and billing processes. Mr. Joyce complains that Mr. Pous' approach would jettison this actual data and analysis derived from the Test Year and improperly substitute arbitrary numbers based upon a prior, dated, rate proceeding.[66]

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[64] *Id.* at 75-77.

[65] ETI Ex. 54 (Joyce Rebuttal) at 11.

[66] *Id.* at 5-7.

Mr. Joyce acknowledged that the RRC recently adopted a 1-day billing lag in the Atmos Mid-Tex RRC proceeding. He pointed out, however, that the RRC did so simply because Atmos Mid-Tex failed to present evidence supporting a longer billing lag. Additionally, Mr. Joyce pointed out that the RRC promptly reversed itself in Atmos Mid-Tex's next rate case, adopting a longer billing lag after the company provided sufficient evidence to support the longer period.[67]

ETI also provided extensive evidence regarding the details of its meter reading and billing process.[68] ETI witness Dolores Stokes explained that the meter reading and billing cycle includes time for extensive quality assurance activities to ensure accurate billing, thereby preventing unnecessary frustration for the customer and additional costs to the Company that would be required for customer service, rebilling, and account corrections.[69]

Cities questioned Mr. Joyce at the hearing about the billing lag period in this case compared to ETI's last rate case. Mr. Joyce explained that the total period from meter reading to collection of billing revenues had not changed appreciably between the two cases, but due to a difference in lead-lag methodology, the date that divides the two components of that lag – metering to billing and billing to collection – had changed.[70] As a result, the first period – billing lag – was longer than in the previous case but the second period – collection lag – was shorter.[71] ETI introduced into evidence a response to a Cities RFI that discussed this difference in more detail.[72] After explaining the change in lead-lag methodology, the RFI response concluded that "the combined billing and collection lags are substantially similar from the prior case to this current case."[73]

The ALJs conclude that ETI has met its burden to show that the billing lag it utilized in the lead-lag study is reasonable and appropriate. Absent his own opinion, Mr. Pous does not offer

[67] *Id.* at 8-9.

[68] ETI Ex. 54 (Joyce Rebuttal); ETI Ex. 66 (Stokes Rebuttal).

[69] ETI Ex. 66 (Stokes Rebuttal) at 18.

[70] Tr. at 499-500, 502.

[71] Tr. at 499-502.

[72] ETI Ex. 73.

[73] ETI Ex. 73 at 2.

meaningful evidence to support his assertion that the Company's billing lag is too long or that the Company's billing practices are inefficient. For example, he offered no criticism of any specific billing practice of the Company. The only support for his charge of inefficiency is that the billing lag in a previous ETI rate case was shorter. Mr. Joyce convincingly explained that this was merely an artifact of changes in the methodology of the lead-lag study – the billing lag became longer, but the collection lag became shorter.

Mr. Pous' reliance upon an example from the RRC is unconvincing. Similarly, his reliance upon data from a previous rate case is unpersuasive, especially because only a very limited snippet of data from that case is available, the case occurred roughly 20 years ago, and it involved a different company. It is not possible, from the evidence in the record, to know how different or similar ETI's current billing practices are to those used in the previous case.

In this case, ETI has thoroughly explained its metering and billing processes and established that those processes are reasonable. The Company is therefore entitled to establish rates based on the actual cash working capital necessary to facilitate those policies. The ALJs recommend rejecting Cities' request to shorten the billing lag time identified in ETI's lead-lag study

(b) Collection Lag

In his lead-lag study, Mr. Joyce identified various collection lags (*i.e.*, the delay between the issuance of an electric bill and the date the customer's payment is received) for different classes of customers. As to third-party customers, the collection lag was determined using a random sample of invoices from residential, commercial, industrial, public authority, and street light customer billings during the Test Year, measuring the time between when the bills were mailed and the payment receipt date. The collection lag for MSS-4 and Intra-System Bill (ISB) revenues was based on the actual payment dates for each of the affiliate revenue types.[74]

[74] ETI Ex. 17 (Joyce Direct) at 10.