AUSTIN ENERGY'S TARIFF PACKAGE: 2015 COST OF SERVICE STUDY AND PROPOSAL TO CHANGE BASE ELECTRIC RATES

§ BEFORE THE CITY OF AUSTIN IMPARTIAL HEARING EXAMINER

REBUTTAL TESTIMONY

OF

JOSEPH A. MANCINELLI

ON BEHALF OF AUSTIN ENERGY

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Joseph A. Mancinelli. My business address is NewGen Strategies and Solutions, LLC ("NewGen") at 225 Union Blvd, Suite 305, Lakewood, Colorado 80228. Currently, I am NewGen's General Manager and President of our firm's Energy Practice. NewGen is a consulting firm that specializes in utility rates, engineering economics, financial accounting, asset valuation, appraisals, and business strategy for electric, natural gas, water, and wastewater utilities. We work for clients throughout the United States. Prior to joining NewGen, I was Vice President of SAIC Energy Environment and Infrastructure, LLC, now Leidos Engineering.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I have a Master of Business Administration degree from the University of Colorado, where my emphasis was in finance. Prior to this, I earned a Bachelor of Science degree from Colorado School of Mines in Geophysical Engineering.

Q. WOULD YOU BRIEFLY DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. I am the General Manager and President of NewGen Energy Practice. I have more than 28 years of experience in the areas of cost of service ("COS") and rate design for electric, water, wastewater, and natural gas utilities. I have worked closely with public utility commissions, senior management teams, utility boards, city councils, attorneys, and end-users with respect to the strategy and technical fundamentals of COS and rate design. I have taught numerous classes in COS and rate design methodology based on approved industry methodologies adopted by the National

Association of Regulatory Utility Commissioners ("NARUC") and the American Public Power Association ("APPA"). I have been extensively involved in the development of unbundled COS and pricing models during my career. A summary of my qualifications is provided as Exhibit JAM-1 to this testimony.

Q. ON WHOSE BEHALF ARE YOU PRESENTING THIS TESTIMONY?

A. I am testifying on behalf of Austin Energy ("AE").

Q. HAS THE TESTIMONY YOU ARE PROVIDING BEEN PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes. This testimony was prepared by me or under my direct supervision.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will explain why certain revenue requirement, COS, and rate design recommendations by intervening parties are inappropriate for AE and should be rejected by the Impartial Hearing Examiner ("IHE").

Q. HAVE YOU REVIEWED THE TESTIMONY OF PARTIES INTERVENING IN THIS CASE?

A. Yes. Specifically, I have reviewed the testimony of Lanetta Cooper and Carol Szerszen representing AE Low Income Customers ("AELIC"); Betty Dunkerley, Greg Hartman, and Geronimo Rodriguez representing Seton Healthcare Family ("Seton"); Scott McCollough representing Data Foundry/Austin Chamber of Commerce ("Data Foundry"); Gary Goble and Marilyn Fox representing NXP Semiconductor and Samsung Austin Semiconductor ("NXP/Samsung"); Clarence Johnson in his role as the Independent Consumer Advocate ("ICA"); and Carol Birch representing Public Citizen and Sierra Club ("PCSC").

Q. GIVEN THIS REVIEW, WHAT ISSUES DO THE INTERVENING PARTIES RAISE THAT YOU ADDRESS IN YOUR REBUTTAL TESTIMONY?

A. The following issues raised by the intervening parties will be discussed in my rebuttal testimony:

- Revenue Requirement issues pertaining to the following:
  - a. The proper funding of non-nuclear decommissioning reserves.
- COS issues pertaining to the following:
  - a. The proper functionalization of 311 Call Center expense and FERC 920 Administration and General Salaries.
  - b. The proper classification of production costs.
  - c. The proper classification of distribution costs.
  - d. The proper allocation of AE production costs.
  - e. The proper allocation of distribution substations, poles, and conductors.
  - f. The proper allocation of customer costs associated with uncollectible accounts or bad debt, metering costs, meter reading, service connection fees, and marketing and advertising costs included in FERC account 908 - Customer Assistance Expense, FERC account 909 - Informational and Instructional Advertising Expense, and FERC account 910 - Miscellaneous Customer Service Expense.
- Rate Design issues pertaining to:
  - a. The proper allocation of the revenue decrease.
  - b. The proper use of billing adjustments in rate design.

II. REVENUE REQUIREMENT

A. Non-Nuclear Decommissioning

Q. WITH RESPECT TO FUNDING THE NON-NUCLEAR DECOMMISSIONING FUND AND DEFEASEMENT OF FUTURE FAYETTE POWER PLANT ("FPP") DEBT SERVICE, WHAT IS THE POSITION OF INTERVENING PARTIES ON THIS SUBJECT?

A. Witness Lanetta Cooper of AELIC, Seton, and Marilyn Fox of NXP/Samsung question the funding level of the non-nuclear decommission reserve.

AELIC indicated the entire amount for decommissioning included by AE in the revenue requirement ($19.4 million) should be excluded from AE's operations and maintenance ("O&M") expense because, according to AELIC, AE did not prove the expense was reasonable and necessary. This was, in part, because AE would not reveal the detail behind the analysis used to develop the decommissioning costs. The rebuttal testimony of Carol Szerszen on behalf of AELIC also criticized AE for treating the decommissioning study details as confidential. Further, AELIC contended that AE should not plan for the high end of the range of decommissioning costs and should adjust the timeframe for recovery. Seton similarly suggested that the $19.4 million be excluded from the revenue requirement and decommissioning be funded, instead, from the Emergency Reserve.

Marilyn Fox testified on behalf of NXP/Samsung that total decommissioning cost recovery should be limited to $12,545,400 for Decker Creek ("Decker") units 1 and 2 and $0 for FPP and Sand Hill Energy Center ("SHEC"). Also, ICA witness Clarence Johnson expressed concerns over the amount requested by AE for decommissioning.

Q. DO YOU AGREE WITH THESE INTERVENORS?

A. No. I will explain why AE's funding proposal represents a prudent and reasonable approach to mitigating the costs associated with this requirement. The non-nuclear decommissioning cost included in the revenue requirement is reasonable and necessary. Further, it is based on an appropriate estimate of this cost. The general approach used to develop the cost estimates, as well as the resulting dollar amounts, were provided to intervenors in a redacted version of NewGen's report.

Q. HOW WAS THE $19.4 MILLION DECOMMISSIONING COST DEVELOPED?

A. As shown in WP D-1.2.5 of the Rate Filing Package ("RFP"), the $19.4 million amount for decommissioning is based on the estimated number of years until the units are retired and the upper end of the range of estimated decommissioning costs (rounded to the nearest $1 million) for units 1 and 2 at Decker, AE's share of the FPP, and all of SHEC, as developed and reported by NewGen in a July 2015 report.[1] The decommissioning costs of Decker units 1 and 2 are based on a detailed engineering cost estimate relying upon analysis specific to these facilities.

Q. WERE THE DECOMMISSIONING COSTS FOR FPP AND SHEC DEVELOPED UNDER THE SAME APPROACH?

A. No. Since the timing of the decommissioning of FPP and SHEC is further into the future, the estimates for FPP and SHEC are based on a benchmarking analysis of scaled costs from actual costs for decommissioning similar power plants. This

[1] Austin Energy's 2015 Cost of Service Study and Proposal to Change Base Electric Rates at 857, WP D-1.2.5 (Jan. 25, 2016) ("Tariff Package").

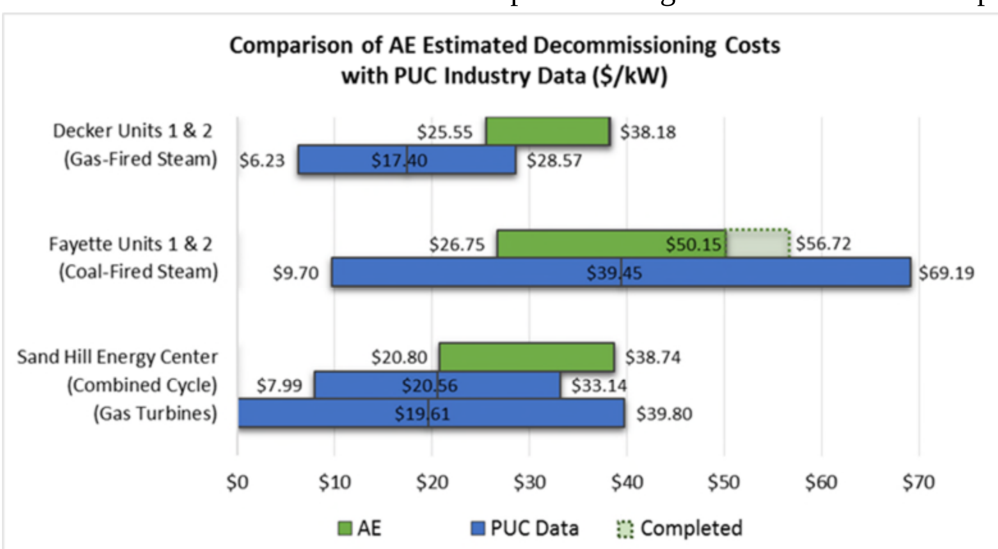
approach is less detailed, but given the length of time before these plants are decommissioned, is appropriate and yields reasonable estimates.

Q. WERE THESE DECOMMISSIONING RESULTS COMPARED WITH ANY OTHER SOURCES OF DATA?

A. Yes. As a point of reference, the results were compared on a cost per kW basis for the different generation technologies to decommissioning costs approved in various cases by public utility commissions in Arizona, Arkansas, Colorado, Florida, Georgia, Indiana, Louisiana, Nevada, New Mexico, and Texas.

Q. WERE THERE DIFFERENCES BETWEEN THE RANGE OF COSTS DEVELOPED FOR AE FACILITIES AND COMMISSION APPROVED COSTS PER KW?

A. Yes. The results are shown below as reported in Figure 1 of the NewGen report.[2]



As shown above, the cost range for Decker units 1 and 2 overlaps the range of commission approved costs identified in the report, but is generally higher than the

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[2] Tariff Package at 427, Appendix I, Final Report Summary of Austin Energy's Reserve Funds.

commission approved costs. However, the decommissioning cost estimate for Decker units 1 and 2 was based on a detailed engineering analysis of these specific facilities as they actually exist, which makes the estimate more reliable than commission approved costs per kW for the same technology in other locations.

For FPP and SHEC, the comparison showed that the ranges developed for AE facilities were within the range of commission approved costs on a per kW basis, thus, validating the benchmarking results.

Q. DO YOU AGREE WITH SETON'S SUGGESTION THAT DECOMMISSIONING BE FUNDED FROM THE EMERGENCY RESERVE?

A. No. Funding decommissioning from the Emergency Reserve would not reflect the appropriate use of these funds. The Emergency Reserve is intended to provide funding in the event of an unanticipated or unforeseen extraordinary need of an emergency nature. The need to decommission AE's facilities is not unanticipated, unforeseen, nor is it an emergency in nature.

Further, if Austin City Council adopts NewGen's recommendations regarding AE's financial reserves, including the elimination of the Emergency Reserve, funding the Non-Nuclear Decommissioning Reserve with the funds from the Emergency Reserve would not be a solution.

Because the Non-Nuclear Decommissioning Reserve is a restricted reserve, meaning that funds in this reserve can only be used for non-nuclear decommissioning expenses, Non-Nuclear Decommissioning reserves would not count towards AE's calculation of Days Cash on Hand. Thus, if AE transferred funds from the Emergency Reserve to the Non-Nuclear Decommissioning Reserve, they would have to replenish these funds in one of the unrestricted reserves to achieve 150 Days Cash on Hand, as discussed in the NewGen report on financial reserves. This would merely move the funding obligation from one fund to another.

Q. WITNESS MARILYN FOX OF NXP/SAMSUNG DEVELOPED AN ALTERNATIVE NON-NUCLEAR DECOMMISSIONING FUNDING LEVEL. HOW DID SHE DEVELOP THIS FUNDING LEVEL?

A. Witness Fox relied on the mean amount of $17.40 per kW listed in the NewGen report for gas-fired steam facilities approved in eight cases by public utility commissions previously mentioned.

Q. WHY DID SHE NOT INCLUDE ANY AMOUNTS FOR FPP OR SHEC?

A. She indicated these were excluded from consideration because they are not planned for retirement within the next four years.

Q. DO YOU AGREE WITH MS FOX'S RECOMMENDATIONS?

A. No. First, by using the mean amount of $17.40 per kW, Ms. Fox ignored the site-specific engineering cost estimate developed for Decker units 1 and 2 and, instead, relied on a general, less-detailed analysis of approved costs for eight other gas-fired steam facilities. The site-specific analysis for Decker units 1 and 2 is more appropriate and reliable than the mean amount approved cost for other gas-fired steam facilities.

Further, it is inappropriate to exclude costs for FPP or SHEC simply because they are not scheduled for retirement within the next four years. Marilyn Fox's recommendation seems to be a misapplication of City Financial Policy No. 21, which states that funding for decommissioning will be set aside over a ***minimum*** of four years prior to the expected plant closure. Policy No. 21 appears to recognize that long-term forward planning, supported with incremental and disciplined funding of decommissioning reserves, will provide adequate funds to mitigate large fluctuations in expenditures when these generation plants are retired. This policy represents prudent financial planning and supports stable, long-term rate making.

Q. WHY SHOULD AE NOT EXCLUDE FPP AND SHEC?

A. AE is obligated to decommission its generation assets. This obligation should accrue over the useful life of the assets. Accordingly, AE should set aside funds for this liability. Ideally, AE would begin setting aside funds for the eventual decommissioning of a plant the day it is put into service. Under this policy, customers that derive the benefits of generation also pay for its eventual decommissioning as the plant is in operation. This is how the cost for decommissioning a nuclear plant is managed. Further, it is similar to how most regulated utilities recover this cost in their depreciation rates, as mentioned by ICA witness Clarence Johnson.[3]

The earlier AE starts the process of setting aside funds for each generation unit, the lower the potential rate impact and the more equitable the recovery of these costs. Therefore, Marilyn Fox's suggestion that no amounts should be set aside for FPP and SHEC until they are within four years of retirement is contrary to the equitable recovery of these costs.

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[3] Direct Testimony of Clarence Johnson at 17:17-18:1 (May 3, 2016).

Q. DID MS. FOX MAKE ANY OTHER RECOMMENDATIONS ABOUT THE DECOMMISSIONING RESERVE?

A. Yes. Ms. Fox suggested that the decommissioning cost should not be included in O&M. I disagree with this contention, but AE witness Mark Dombroski will comment further on the appropriateness of this cost being included in O&M.

Q. WHAT WERE ICA WITNESS JOHNSON'S CONCERNS?

A. Witness Johnson contends that AE did not fully account for "salvage value," or the revenues from recycling or selling components, in its decommissioning cost estimates and, thus, the estimates are on the high side. He also commented on the contingencies included in the cost estimate. Further, Mr. Johnson is concerned with AE not setting aside any funds for decommissioning Decker, FPP, or SHEC and the time frame for recovering these costs.

Q. DO YOU AGREE WITH CLARENCE JOHNSON'S SALVAGE VALUE AND CONTINGENCY CONCERNS?

A. No. He made several observations, but they do not warrant an adjustment to the annual decommissioning cost requested by AE.

Q. WHAT WERE WITNESS JOHNSON'S OBSERVATIONS ON SALVAGE VALUE?

A. Witness Johnson pointed out that the decommissioning cost estimates did not include offsetting revenue from the sale of water rights, land, or working equipment. However, the high-level cost estimates developed for FPP and SHEC did not have enough detail for such offsetting revenue assumptions.

Regarding Decker, there will continue to be combustion turbines in operation at the site, so there is little opportunity to sell the land after units 1 and 2 are retired. Further, the sale of water rights is too uncertain to be a quantifiable offset to the decommissioning cost at this time, although this could be included in a future update if a potential purchaser and terms are identified. The sale of working equipment was similarly uncertain and AE's experience decommissioning the Holly Power Plant indicates the opportunity to obtain such offsets from the sale of equipment may be negligible.

Q. WHAT WERE CLARENCE JOHNSON'S OBSERVATIONS ON THE PROPOSED CONTINGENCY AMOUNTS?

A. He observed that the contingency amount included within the decommissioning cost estimates ranged from 10.7% for Decker units 1 and 2 to 30% for FPP and SHEC. Further, the 30% contingency for FPP and SHEC only applied to demolition costs, and not recycling and salvage offsets. He also mentioned that the Public Utility Commission of Texas ("PUC") does not permit contingency allowances greater than 10% for nuclear decommissioning and that it recently found, in a case for Southwestern Power Co., that a net salvage value of -2% should be applied to all production plant, implying depreciation must recover 2% above gross plant cost to cover decommissioning.[4]

Q. ARE YOU PERSUADED BY HIS OBSERVATIONS?

A. No. The fact that the PUC does not permit contingency allowances greater than 10% for nuclear decommissioning is not a relevant limitation since the approach and

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[4] *Application of Southwestern Public Service Company for Authority to Change Rates,* Docket No. 43695, Order on Rehearing at Finding of Fact No. 119 (Feb. 23, 2016).

requirements for nuclear decommissioning are different from the analysis conducted for AE's non-nuclear generation facilities. However, it is important to note that:

1. The detailed Decker decommissioning estimate includes a 10.7% contingency on demolition costs (excluding salvage), which is very close to the PUC 10% nuclear decommissioning guideline; and
2. The majority of the non-nuclear funding requirement included in the RFP is related to Decker.

So, although unintentional, the overall contingency associated with the total funding requirement is reasonably close to the PUC 10% guideline.

In contrast to the Decker decommissioning estimate, the FPP and SHEC decommissioning estimates were developed at a high level. Given these high level estimates, a 10% contingency would not reasonably reflect the uncertainty inherent in the analysis. Similarly, it is appropriate to apply the 30% contingency to the demolition costs for FPP and SHEC, excluding the recycling and salvage offsets, because unknown or unidentified costs are a more significant concern than potentially understated salvage revenues in the way this analysis was developed. Further, what the PUC decided for an investor-owned utility (i.e., Southwestern Power Co.) is not directly applicable to AE given the differences in the way these utilities are regulated, develop revenue requirements, and recover costs for decommissioning.

Finally, witness Johnson's citation of a -2% net salvage value as referenced in PUC Docket No. 43695, which is presumably associated with interim retirements rather than ultimate decommissioning, is of no importance in the initial establishment of a non-nuclear decommissioning reserve. However, it is important that non-nuclear decommissioning reserves are restricted for use in decommissioning the Decker, FPP, and SHEC generating stations. When these stations are decommissioned, available funds will be used to offset actual costs. To the extent that actual costs exceed funds accrued, additional revenues from rates will be required. To the extent that actual costs are less than the funds accrued, funds can be applied to other non-nuclear decommissioning requirements or may become “unrestricted” to be used to offset other AE expenses. In either case, adequate funding of this reserve stabilizes rates.

Q. WHAT WAS WITNESS JOHNSON’S RECOMMENDATION ON DECOMMISSIONING COSTS?

A. He recommended a 48% reduction to AE’s annual decommissioning expense. He developed this recommended amount based on the mean cost per kW for the different generation technologies approved by public utility commissions in various cases as cited in the NewGen report.

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. As previously stated, the cost per kW for the different generation technologies approved in various cases by public utility commissions was used as a point of reference to compare with the decommissioning cost estimates developed for AE’s facilities. It is inappropriate to rely on the mean approved cost per kW from other plants when there is site-specific information based on a detailed engineering cost estimate available, as previously discussed. Further, the approved commission data validated the cost estimates developed for FPP and SHEC under a benchmarking approach. Thus, the amounts used by AE for decommissioning are appropriate.

Q. WHY IS IT APPROPRIATE FOR AE TO USE THE HIGH END OF THE RANGE FOR DECOMMISSIONING COST RECOVERY?

A. Decommissioning costs are estimates and, thus, the actual cost of decommissioning may be much higher than the estimates indicate. AE’s experience decommissioning the Holly Power Plant is instructive in this regard, as decommissioning activities at this site were longer, more extensive, and more expensive than originally estimated. Planning for the high end of the range decreases the likelihood that AE will have insufficient funding, requiring the utility to seek additional funds immediately from ratepayers. The decommissioning cost estimates will be updated periodically to allow funding needs and contributions to be refined. In the event that decommissioning expenses are less than funds collected, AE can use the remaining funds to offset the cost of the next plant to be decommissioned. Also, AE has a unique opportunity to fund this critical reserve under a revenue reduction scenario. In the RFP, AE is proposing to fund the decommissioning reserve at the upper justifiable level and reduce overall system rates. From a rate administration perspective, this strategy is prudent because:

1. Given the timing of the Decker decommissioning, immediate funding of the Decker component of the Non-Nuclear Decommissioning Reserve is critical.
2. Funding the Non-Nuclear Decommissioning Reserve at the justifiable upper end will reduce the risk of future funding requirements from rates.
3. AE would not have to reduce overall system base rates to an unsustainable level, only to raise them in the next rate case. Using a portion of current base rate revenues to fund the Non-Nuclear Decommissioning Reserve satisfies an important revenue requirement objective without raising rates. This outcome is more desirable compared to facing a similar funding requirement when an overall rate increase is required.

Q. WHAT IS YOUR OPINION OF WITNESS JOHNSON'S INTERGENERATIONAL EQUITY CONCERNS?

A. Although AE's historical practice of not setting aside funds for decommissioning Decker, FPP, or SHEC may raise intergenerational equity concerns, this issue will only be made worse by under-funding the decommissioning reserve. Thus, fully funding the reserve is the best way to mitigate this issue going forward. The flow of potential excess funding to the next decommissioning project is reasonable given the fact that AE has not started collecting decommissioning funds for plants that have been in service for a decade or more. This structure would allow current customers, who have benefited from the use of AE's current generation fleet, to bear some of the cost responsibility of the decommissioning expenses associated with those assets.

III. COST OF SERVICE

Q. PLEASE SUMMARIZE COS ISSUES RAISED BY THE VARIOUS INTERVENING PARTIES.

A. The intervening parties' recommendations with respect to COS issues are as follows:

1. **Functionalization of 311 Call Center Expense and Administration and General Salaries –** ICA witness Johnson recommends that 311 Call Center Expense be functionalized to the distribution function instead of the customer function. He further recommends that Administration and General ("A&G") salaries be functionalized using a Non-Fuel O&M allocation factor, whereas AE allocated these costs to each function based on labor. I will discuss why AE's functionalization of these expenses is correct.

2. **Proper Classification of Production Costs –** Mr. Johnson recommends classification of production costs using the NARUC Cost Accounting approach. I will explain why this approach is inappropriate given AE's current business environment. This explanation will also address inaccurate claims by AELIC that production costs are not fixed.

3. **Proper Classification of Distribution Costs –** Mr. Johnson recommends classification of transformers and capacitors as energy related, instead of demand related. He also recommends that meter expenses be classified as both customer and demand related instead of solely customer related. Also, Mr. Johnson recommends the classification of services as customer related, instead of demand related. I will explain why AE's classification approach associated with these expense items is appropriate and correct. Additionally, to address concerns of AELIC regarding the proper classification of distribution costs, I will discuss why distribution costs are classified as either demand related or customer related. In either case, these costs are fixed in nature.

4. **Proper Allocation of Production Costs –** Mr. Johnson recommends allocation of AE production costs using the Baseload, Intermediate and Peaking ("BIP") method. Witness Birch of PCSC recommends allocation of AE production costs using either BIP, Probability of Dispatch ("POD") or on

Hourly Energy Cost. Data Foundry and NXP/Samsung recommend the use of the Average and Excess 4Coincident Peak ("A&E 4CP") method. I will explain why production energy weighted allocation methods, such as BIP, POD and Hourly Energy Cost, are not appropriate allocators of production costs in the ERCOT market. Also, I will explain why the 12CP Peak Demand allocator used by AE in the RFP is a reasonable improvement to the A&E 4CP demand allocator used in AE's last rate case.

5. **Proper Allocation of Distribution Substations, Poles and Conductors –** NXP/Samsung witness Goble recommends using the 1Non Coincident Peak ("NCP") allocation method for substations, poles and conductors. I will explain why AE's use of the 12NCP allocator for these infrastructure items is more appropriate.

6. **Proper Allocation of Certain Customer Costs –** ICA witness Johnson makes the following cost allocation recommendations:

   a. allocate uncollectable accounts using the AE revenue requirement, rather than AE's direct assignment of these costs;

   b. allocate metering expense using a combination of customer and demand allocation factors, rather than AE's use of a weighted customer allocator;

   c. allocate meter reading costs using weighted meter investments, rather than AE's use of the number of customers;

   d. allocate marketing and advertising costs using weighted customers, rather than AE's use of number of customers; and

   e. allocate service connection fees based on number of customers, rather than AE's method of allocating these costs similar to the allocation of services. AE allocates services based on the Sum of Maximum Demands ("SMD").

I will explain why AE's proposed allocations for these items is more appropriate than those proposed by ICA witness Johnson.

A. Functionalization of the 311 Call Center, FERC 920 Administration and General Labor Costs and New Service Connection Fees

Q. PERTAINING TO AE'S COS STUDY, ICA WITNESS JOHNSON RECOMMENDS THAT COSTS ASSOCIATED WITH THE 311 CALL CENTER BE ASSIGNED TO THE DISTRIBUTION FUNCTION RATHER THAN THE CUSTOMER FUNCTION. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. Mr. Johnson's recommendation misinterprets the use and benefit of the 311 Call Center. His proposal to functionalize the 311 Call Center to distribution and allocate these costs to rate classes using distribution O&M expense would result in customers with larger demands paying a greater share of 311 Call Center costs compared to customers with smaller demands. This cost allocation proposal is unsupportable and his recommendation should be rejected. The benefit associated with access and use of the 311 system is the same for customers of all sizes.

AE properly functionalizes the 311 Call Center to the customer function. The 311 Call Center is a communication system that connects users with various city departments, including Austin Energy. The cost of the call center is driven by call volume, which can best be associated with the number of customers. As a result, the 311 Call Center should be functionalized to customers and allocated to each rate class based on the number of customers. The 311 Call Center provides a community benefit. This benefit is fairly recognized equally between customers.

Mr. Johnson contends that the disaster recovery portion of the 311 Call Center cost is presumably focused on restoring power service, but this cost actually has nothing to do with grid operations. Emergency use of the Call Center is no different from normal use of AE's customer service center. In both cases, customers are able to call and report service interruptions, billing issues, or other concerns to AE and other City departments. The disaster recovery benefits of the 311 Call Center are associated with a remote site that can be used on a moment's notice to avoid disruption of availability. The 311 Call Center provides AE communications redundancy with the same underlying use and benefit as the customer service center. For these reasons, AE's COS treatment of the 311 Call Center is reasonable and should be adopted.

Q. PERTAINING TO AE'S COS STUDY, MR. JOHNSON RECOMMENDS THAT FERC ACCOUNT 920 - A&G LABOR COSTS BE ALLOCATED TO EACH FUNCTION USING NON-FUEL O&M RATHER THAN LABOR EXCLUDING A&G. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. The proper allocation of A&G labor costs is the use of a labor allocator. A labor allocator recognizes that the primary administrative function of the utility is the management of the labor force. Use of a non-fuel O&M allocator, as proposed by Mr. Johnson, distorts this COS relationship and unduly shifts costs to the generation function. O&M includes a large amount of non-labor expense items that can vary by year and function. A large portion of these expenses are related to infrastructure maintenance requirements. These expenses do not align well with the level of effort of the management team or the underlying staff. This is particularly true for the production function, which is subject to periodic expensive unit overhauls. Compared to other functions, non-labor maintenance cost is very high for production. This is shown in the following table which compares test year labor cost as a percentage of total costs by function. Please note that the production function O&M calculation shown below excludes FPP and the South Texas Project ("STP").

Function	AE Labor Costs[1]	AE Non-Fuel O&M (Excluding Transmission by Others, FPP & STP)[2]	Percent of O&M that is Labor Related
Production	$23,018,932	$146,927,138	15.7%
Transmission	$10,112,235	$13,872,035	72.9%
Distribution	$39,788,187	$60,207,313	66.1%
Customer	$37,972,802	$60,540,745	62.7%

1. Labor Data from RFP WP D-3
2. Non-Fuel O&M from RFP WP F-1.9 with adjustments from Schedule G-2 & Schedule G-3

Labor cost as a percent of total O&M is significantly lower for the production function compared to the other functions because non-labor expenses are much higher for the generating units compared to transmission and distribution infrastructure. As a result, O&M less fuel is a poor allocator of A&G costs because this method unjustly shifts a significant amount of management labor costs to the production function.

With respect to his arguments pertaining to STP and FPP, witness Johnson misrepresents AE's allocation of FERC Account 920 - A&G labor expenses. AE correctly allocates these costs using labor, then directly assigns an additional $3.3 million in A&G labor costs to the production function for STP and FPP administration costs. AE accounts for these costs separately, therefore, they can be directly assigned. In total, when accounting for the direct assignment, AE allocates approximately 28% of total FERC 920 costs to the production function. This is 7% higher than what would be otherwise allocated using a labor allocator without a direct assignment. AE recognizes the cost of A&G labor associated with FPP and STP and properly handles this in the allocation method.

Finally, Mr. Johnson acknowledges that his proposed allocation method significantly shifts the allocation of A&G costs to the production function. He claims that this result is justifiable because all customers on the system use the production function compared to transmission and distribution functions. For example, customers receiving electricity service at higher voltages only pay for a portion of the transmission and distribution systems. Witness Johnson seems to imply that these high delivery voltage customers are not paying their fair share of A&G costs compared to customers with secondary delivery voltages. This is not true. A&G expense is a necessary indirect cost associated with all utility functions. These costs are properly allocated to each function based on labor costs. In the RFP, within each function, these costs were further assigned to each sub-function using a combination of direct assignments and labor allocators. The end result of this allocation process is that the various components of the AE production, transmission, distribution, and customer service functions include a reasonable amount of indirect costs, including FERC Account 920 A&G labor. Customer use of these various system components dictate the appropriate COS responsibility associated with these indirect costs. High service voltage customers should only be required to pay their fair share of indirect costs associated with high voltage infrastructure. Witness Johnson's proposal would disproportionally shift indirect costs to the production function and away from the transmission and distribution functions. As a result, large electric users will pay too much of these overhead costs while small users will pay too little. For these reasons, Mr. Johnson's A&G COS proposal should be rejected.

Q. MR. JOHNSON RECOMMENDS ASSIGNING NEW SERVICE CONNECTION FEES TO THE CUSTOMER FUNCTION RATHER THAN DISTRIBUTION FUNCTION. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. As clearly stated in AE's Response to ICA RFI 7-3, New Service Connection fees are collected for initiating new services and reconnecting after failure to pay.[5] These services directly relate to the distribution system infrastructure required to connect the customer. Therefore, these costs are properly functionalized to the distribution system.

B. <u>Classification of Production Costs</u>

Q. MR. JOHNSON RECOMMENDS USING THE NARUC COST ACCOUNTING APPROACH FOR THE CLASSIFICATION OF PRODUCTION O&M ACCOUNTS. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No. Although many of the classification guidelines described in the NARUC Cost Allocation Manual ("CAM") remain valid, guidelines pertaining to the classification of production infrastructure must now be interpreted in light of new market conditions. The description of fixed and variable production costs in the CAM were developed when the electric utility industry was comprised of vertically integrated utilities operating in a monopoly business environment. These guidelines were developed long before the deregulation of wholesale power markets. In this traditional business model, utilities enjoyed predictable load growth with no direct competition. In this business environment, fixed costs could be confidently recovered through energy charges with little financial risk and often much benefit to utilities.

[5] AE's Response to ICA RFI No. 7-3 (Apr. 28, 2016) (Exhibit JAM-2).

Generation assets directly served load and were utilized regardless of cost. Revenue certainty from rates was high and supported by strong load growth.

In this traditional business environment, the definition of variable costs was broader and included many costs that did not vary on a short-term basis. Also, in many ways, beyond true short-run variable costs like fuel, the definition of variable costs was less important as rate design often ignored these differences. A common practice in rate design has been to recover a large portion of fixed costs in energy charges contrary to COS results. With a large percentage of fixed costs included in energy rates, strong load growth provided long-term economic benefits to utilities. With robust load growth, revenues from energy rates outpaced increasing fixed costs. This result allowed utilities to build significant reserves and avoid rate changes for long periods of time. This cost classification and rate design approach no longer works in the current utility business environment. Today's business environment in the Electric Reliability Council of Texas ("ERCOT") is very different from the monopoly environment of vertically integrated utilities that existed when NARUC's CAM Cost Accounting classification guidelines were published. Significant changes in the ERCOT power market have impacted the industry's business operations. Like other utilities, AE is faced with a competitive wholesale power market, aggressive conservation and demand response goals, increased interest in distributed generation options by customers, and long-term, low-load growth projections. All of these factors create load uncertainty, energy volatility, and greater revenue instability. Fixed cost recovery is no longer certain in the wholesale power market or through rates.

Q. HOW DOES THE NARUC CAM DEFINE VARIABLE COSTS?

A. The NARUC CAM Cost Accounting Approach as described in the CAM on pages 35-38, classifies production plant and expenses as either being demand related or energy related. In the classification of energy related expenses, the CAM considers costs that vary on a day-to-day basis (short-run variable costs) and costs that vary over much longer periods of time (long-run variable costs). In total, the CAM classifies these costs as variable in nature.[6] Depending upon the underlying technology of the generation asset, the proportion of energy related costs that vary over the short-run and vary over the long-run change. For steam and nuclear generation, the long-run view classifies a portion of non-labor materials operation expenses and a majority of maintenance expenses as energy related. The logic is simple – if the unit runs, it must be maintained, so these O&M costs vary over the long-run and are energy related. The short-run view classifies variable costs as costs that vary depending on the daily operation of the unit. These costs are fuel and variable O&M, which include, for example, chemicals and water. For combustion turbines and other peaking units, the NARUC CAM only considers fuel, a short-run variable cost, as energy related. All other costs are classified as demand related. CAM distinctions between short-run variable costs that change based on the day-to-day operation of a power plant, and long-run variable costs that may change over several years, become important in a competitive wholesale power market. In ERCOT, generation competes to serve load and is offered into the market based on a unit's short-run variable cost. As a result, short-run variable cost is the primary economic driver influencing the dispatch of generation in the market. Using a short-

[6] Electric Utility Cost Allocation Manual, January 1992, p. 35.

run variable cost definition results in a classification of generation energy-related costs that are consistent with market economics. The CAM's consideration of long-run variable costs are not applicable to generation facilities in a nodal market and are more appropriately considered a demand-related cost. I will discuss the proper classification of production O&M expenses later in my testimony. Therefore, the CAM classification guidelines pertaining to production infrastructure that ICA has relied upon are not relevant and should not be considered by the IHE.

Q. HOW DOES THE RFP CLASSIFICATION OF PRODUCTION COSTS DIFFER FROM THE NARUC CAM?

A. The RFP classifies fuel and 100% of recoverable purchased power as energy related expenses. This classification is consistent with the short-run view and represents a large percentage of AE's short-run variable costs. Use of the short-run view closely reflects actual variable costs incurred by AE when units are dispatched into the ERCOT market. When AE bids generation into the market, the bid accounts for short-run variable costs such as fuel cost (including delivery), variable O&M ("VOM"), and unit start-up and shut-down costs. Mr. Johnson acknowledges this fact in his testimony, which states:

> Under ordinary conditions, generators will submit bids close to the generation unit's variable cost in order to ensure that the unit operates when it is economic to do so. As a result, the generating units' annual hours of operation will depend on its variable costs.[7]

AE's classification of production variable costs aligns with the economics of generation dispatch in ERCOT and reflects costs AE will recover from the market.

[7] Direct Testimony of Clarence Johnson at 45:8-11.

Depending upon market prices, other costs above and beyond these short-run variable costs may be recovered, but this is not guaranteed. As a result, AE customers are ultimately responsible for some or all of the generation costs above short-run variable costs. Given that it is proper to recognize short-run variable costs as energy related, it is also proper to recognize O&M expenses as demand related. AE generation assets must be in a state of "readiness to serve," or operationally available, when market conditions provide economic opportunities for dispatch. O&M practices are critical in keeping units available to operate on short notice. In the current business environment, AE measures Commercial Unit Availability ("CUA"). CUA is a critical performance indicator that measures the availability of a unit to operate when the unit is "in the money," or struck in the market. With high CUA, AE generation resources can effectively act as a financial hedge and protect customers from costly market events. O&M expenses (excluding fuel and VOM) ensure high CUA and capacity-on-demand for all AE generation resources. Therefore, these O&M expenses are properly classified as demand related costs in the nodal market. For these reasons, Mr. Johnson's production function classification recommendations should be rejected.

Q. AELIC WITNESS COOPER CLAIMS THAT PRODUCTION FIXED COSTS ARE INCONSISTENT WITH THE COS. IS HER ASSESSMENT CORRECT?

A. No. The NARUC CAM, on page 35, describes fixed costs as costs that change with capacity additions, and variable costs as costs that change with the production of energy. AE's interpretation of fixed and variable costs, included in the RFP, is consistent with this description. AE identified variable production costs from a short-term perspective consistent with the ERCOT market. The COS analysis contained in the RFP classifies fixed and variable production costs using this approach.

C. Classification of Distribution Costs

Q. ICA WITNESS JOHNSON RECOMMENDS CLASSIFICATION OF A PORTION OF TRANSFORMERS AND CAPACITORS AS ENERGY RELATED. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No. To ensure reliability of service to customers, distribution transformers are sized to meet customer maximum demands on the system. Further, transformer costs are fixed, meaning that they do not vary with energy use. It is standard industry practice to classify transformers as demand related costs and allocate these costs on some measure of customer demand. In the RFP, AE allocates these costs using the SMD method. SMD reflects the maximum monthly demand a customer places on the system during each month of the year. This classification approach has been widely accepted by the PUC in prior rate proceedings.[8] Also, Transmission and Distribution Utility ("TDU") rate structures approved by the PUC and applied to customer classes with demand meters recover distribution costs entirely from customer and demand charges. This fact illustrates that transmission and distribution costs are not related to energy. While it is true that energy is lost during the transformation process, the underlying cost driver of this investment is demand. Using Mr. Johnson's logic, a

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[8] *Application of Southwestern Public Service Company for Authority to Change Rates,* Docket No. 43695 (Feb. 23, 2016); *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 41791 (May 16, 2014); *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896 (Nov. 2, 2012); *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 37744 (Dec. 13, 2010); *Application of CenterPoint Energy Houston Electric, L.L.C. for Authority to Change Rates*, Docket No. 38339 (June 23, 2011); *Application of Sharyland Utilities, L.P. to Establish Retail Delivery Rates, Approve Tariff for Retail Delivery Service, and Adjust Wholesale Transmission Rate*, Docket No. 41474 (Jan. 23 2014).

customer using little to no energy would pay nothing associated with the installed transformers dedicated to serve that customer's load. Yet, when this customer needs electricity, the transformer investment is standing by to meet that demand requirement. Clearly, the transformer provides a significant benefit to the customer and that benefit is best measured with demand.

Mr. Johnson's logic is also inconsistent with the development of standby rates that backup customers who self-generate. Among other things, standby rates recover the cost of distribution infrastructure, like transformers, through a monthly fixed charge. The monthly fixed charge recognizes that this utility investment is valuable to the customer in the form of grid access and reliability, regardless of the amount of energy used. For similar reasons, capacitors are classified as demand related expenses. Capacitors are required on the system for voltage support and represent fixed costs to the utility. For these reasons, witness Johnson's recommendation to classify a portion of transformer and capacitor costs as energy related should be rejected.

Q. AELIC WITNESS COOPER CLAIMS THAT DISTRIBUTION FIXED COSTS ARE INCONSISTENT WITH THE COS. IS HER ASSESSMENT CORRECT?

A. No. Distribution costs are classified as either demand or customer related. In either case, these costs are fixed and do not vary with the amount of energy produced. As defined by the NARUC CAM, demand related costs change as the AE system grows, but these added costs are associated with new investment, not fluctuations in customer energy use. Similarly, customer related costs will change as AE adds customers, but once these customers are added to the system, these costs are essentially fixed. The COS analysis contained in the RFP classifies distribution costs as demand related and customer related. In both cases, these costs are fixed in nature.

Q. ICA WITNESS JOHNSON RECOMMENDS CLASSIFICATION OF METERS TO BOTH CUSTOMER RELATED AND DEMAND RELATED RATHER THAN ONLY CUSTOMER RELATED AS AE PROPOSES. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No. The costs of meters are a function of the number of customers and are, therefore, correctly classified by AE as customer related costs. A customer related classification is supported by the NARUC CAM and the PUC routinely uses this classification in TDU rate cases.[9] Additional costs of metering equipment for larger customers has already been accounted for in the COS by the application of a customer count allocation of meter costs using a weighted meter cost.

Classifying a portion of meter costs as demand related, as Mr. Johnson suggests, would result in shifting metering costs from customers with small demand requirements to customers with large demand requirements. This would result in cross subsidization of metering costs where small demand customers, like residential customers, would pay too little for metering expense and large commercial customer would pay too much.

Mr. Johnson supports his demand allocation argument by alluding to demand response and load shifting benefits potentially derived with advanced metering infrastructure ("AMI") meters and new rate designs. Currently, any benefits associated with these types of customer responses are small on the system. According to AE's Response to ICA RFI No. 1-20, all commercial and industrial

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[9] *Id.*

meters and 30% of residential meters are currently capable of providing interval data.[10] Currently, only 10% of all commercial and industrial customers and 10% of all residential customers are currently sending interval data back to the utility. If benefits do exist, they are related to the avoided cost of future investments on the production, transmission, and distribution systems. These potential future benefits are not related to the metering investment, which remains an investment made on a per customer basis. For these reasons, Mr. Johnson's recommendation to classify a portion of metering cost to demand should be rejected.

Q. ICA WITNESS JOHNSON RECOMMENDS CLASSIFICATION OF SERVICES AS CUSTOMER RELATED RATHER THAN DEMAND RELATED AS AE PROPOSES. DO YOU AGREE WITH HIS RECOMMENDATION?

A. Services can be classified as customer related expenses. However, when this classification approach is pursued, the underlying customer allocator is weighted between classes. This weighting recognizes that service costs vary between customers based on the customers' demand requirements. For example, in 2011, Oncor, in Docket No. 38929, used a weighting of approximately 1 for residential, 10 for secondary >10kW, and 100 for large primary/transmission.[11] Further, in regard to services, the NARUC CAM states:

> This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

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[10] AE Response to ICA RFI No. 1-20 (Mar. 14, 2016) (JAM-3).

[11] *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, Docket No. 38929 (Aug. 26, 2011).

Given that any weighting of services is based on class demand requirements, AE's classification of services as demand related and the allocation of the cost to each class based on SMD is a reasonable and fair treatment of these costs.

Even if one assumes services are a customer related expense, rate class weighting factors would be similar to SMD allocators previously discussed. As a result, the impact of this classification change on COS results would be minor. Also, such a classification would make service costs eligible to be included in the customer charge of each rate class rather than a component of demand. Again, however, this change in treatment would have little impact on rate design. This is particularly true for the residential class, where the proposed residential customer charge is less than half what could be reasonably charged based on the COS analysis. For these reasons, witness Johnson's recommendation to classify services as customer related should be rejected.

D. <u>Allocation of Production Costs</u>

Q. ICA WITNESS JOHNSON AND PCSC WITNESS BIRCH RECOMMEND THAT DEMAND RELATED PRODUCTION COSTS BE ALLOCATED TO RATE CLASSES USING THE BIP ALLOCATION METHOD, OR OTHER SIMILAR BUT MORE COMPLEX ALLOCATION METHODS THAT ALLOCATE COSTS USING ENERGY. IS THE BIP ALLOCATION METHOD A REASONABLE METHOD FOR AE?

A. No, the BIP allocation method is not appropriate for AE because:

- The BIP method is a production stacking method where baseload, intermediate, and peaking units are dispatched over the course of the year to meet AE's load. This allocation method is not relevant to the ERCOT nodal market where generation units are economically dispatched into the market and not dispatched to serve AE's hourly load requirements.

- Broad generation terms such as baseload, intermediate, and peaking no longer have traditional meanings in ERCOT. Unit dispatch has changed since the advent of the nodal market in some cases dramatically. In this market, categorizing units as baseload, intermediate, and peaking are much less meaningful. Therefore, similar BIP categories and associated demand and energy classifications are not relevant.
- As mentioned earlier in my testimony, a primary concern of AE is CUA. Sufficient CUA enables AE to provide an effective financial hedge for customers in a volatile market. The effectiveness of the hedge can be measured by available unit capacity compared to AE system demand. The more effective the hedge, the greater the capacity value is to AE's customers. However, BIP assigns zero capacity value to the FPP and STP baseload units. Therefore, BIP severely understates the capacity value of generation, given the significant value of CUA in the ERCOT market.
- The effectiveness of the financial hedge provided by the generation fleet is a function of available capacity concurrent with AE's peak load requirements. Therefore, fixed production costs are most appropriately associated with demand, not energy. As a result, energy allocation methods, like BIP and POD, are not appropriate. These methods weight peak hours too heavily and disproportionally shift costs from low-load factor classes to high-load factor classes.
- Historically, BIP has not been recognized by the PUC as an approved production cost allocation method.

Q. YOUR FIRST POINT IS THAT AE GENERATION RESOURCES ARE NOT DISPATCHED TO SERVE AE LOAD. WHAT IS THE BASIS FOR UNIT DISPATCH IN ERCOT?

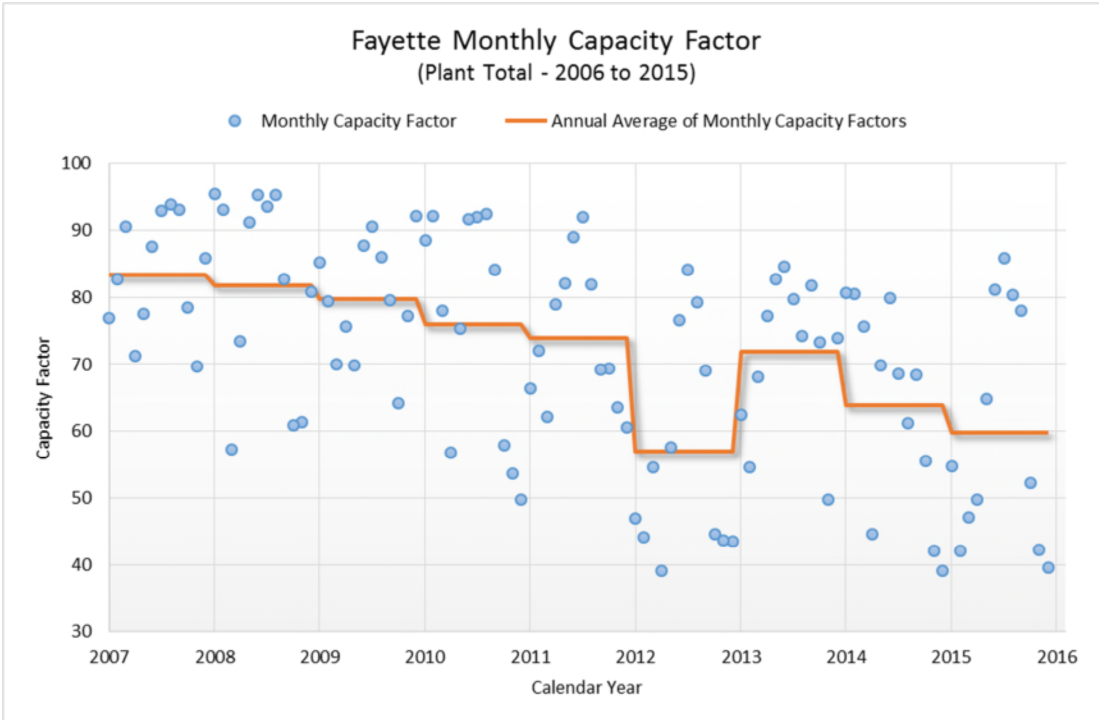
A. Within the ERCOT wholesale market, all generation units are economically dispatched into the market based on an offer price established by the owner. As previously mentioned in my testimony, AE's offer price considers fuel cost, fuel delivery, VOM, startup and shutdown costs, and other factors. Given this price, ERCOT dispatches units to serve overall market load requirements. Given low price market conditions, AE generation resources may sit idle for long periods of time. Conversely, during high price market conditions, all AE generation resources may be dispatched. Because generation dispatch is dictated by market prices, at any given hour during the year, unit dispatch does not equal AE system load requirements. This is significantly different from the traditional vertically integrated monopoly utility model in which the BIP allocation method and other production dispatch methods were developed. Within this traditional business model, generation resources were dispatched hourly to meet system load requirements. A portfolio of generation assets often included baseload, intermediate and peaking units. In total, some combination of these resources were utilized to meet system load for each hour of the year. This relationship between the hourly dispatch of generation and the hourly system load requirements no longer exists in ERCOT. Therefore, BIP and other similar generation allocation methods that heavily weight energy use or hourly system load requirements by class are inappropriate and should be rejected.

Q. HOW DOES AE MEET ITS SYSTEM LOAD REQUIREMENTS?

A. AE buys power from the market at the market price on a sub-hourly basis to serve load.

Q. YOUR SECOND POINT IS THAT BROAD GENERATION CATEGORIES OF BASELOAD, INTERMEDIATE, AND PEAKING UNITS NO LONGER APPLY IN THE ERCOT MARKET. PLEASE EXPLAIN.

A. As previously mentioned in my testimony, the offers from generation resources dictate the dispatch of generation units in ERCOT. As such, market conditions, not generation technology, drive dispatch. To illustrate this point, I have calculated the monthly average capacity factor of FPP from 2007 (before the ERCOT nodal market) to 2016. The ERCOT nodal market began operation in December 2010.



As shown in the above graph, the FPP capacity factor has dropped from an average annual monthly amount of 83% in 2007 to a low of 57% in 2012. This reduction in unit capacity factor has been directly related to market prices in ERCOT. Although FPP is a relatively efficient power station, the unit has not been consistently fully dispatched under current market conditions. Although witness Johnson categorizes FPP as a baseload unit, it is difficult to justify this categorization based on an average monthly capacity factor of approximately 60%. A 60% average monthly capacity factor means that the unit operates at 60% of the unit's capable output, whereas, in the traditional sense, you would expect a baseload unit to run at 80% to 90% of capable output. FPP did operate a these high capacity factor levels in the pre-nodal market.

Because of market conditions, with the exception of STP, AE cycles all generation units regardless of technology. Cycling is required to take advantage of market opportunities, protect AE customers from high market prices, and act as a financial hedge. In reality, AE's generation portfolio acts more like a peaking portfolio, where unit demand is dispatched in the market for the financial benefit of all AE customers. Dispatchable demand, as measured by CUA, is a valuable economic component provided by the AE generation portfolio.

Q. WHY DOES STP NOT CYCLE LIKE OTHER AE GENERATING UNITS?

A. Given that STP is a nuclear resource, unit operation is strictly controlled by the United States Nuclear Regulatory Commission guidelines and dictated by the unique nature of the fuel source. When operating, STP is in a "must run" situation regardless of market economic conditions.

Q. SHOULD THE BIP METHOD BE APPLIED TO STP?

A. No. STP's unique operating requirement does not justify special allocation treatment compared to AE's remaining generation portfolio. STP provides a valuable capacity resource to AE within the hedging function. The BIP method would not attribute any capacity value to STP. This is one of many flaws with the BIP method. Application of the BIP method for STP should not be considered.

Q. DO ALL GENERATION UNITS HAVE AN IMPORTANT CAPACITY VALUE IN THE MARKET?

A. Yes. In support of my third and fourth points listed above, AE's generation assets that are available and dispatchable when market economics are favorable provide an important capacity value and financial hedge to AE customers. The effectiveness of AE's financial hedge is CUA, as measured in MWs compared to AE's system peak demands. Having enough dispatchable capacity to cover peak demand requirements is a critical cost causation driver in the current market. Therefore, demand related costs associated with AE's generation portfolio are incurred to serve as a financial hedge. The financial hedge can only be effective if CUA capacity meets or exceeds the system peak. Demand related costs associated with system capacity are incurred to meet system peaks. The proper reflection of this cost causation relationship is the use of a 12CP allocation method.

Q. HAS THE PUC RECOGNIZED BIP AS A REASONABLE ALLOCATION METHOD?

A. No, in recent years, not to my knowledge. The PUC and other states in the region have traditionally approved production cost allocation methods that are based on Coincident Peak, A&E, or some hybrid of the two.

Q. MR. MANCINELLI, HAVE YOU REVIEWED THE CROSS REBUTTAL TESTIMONY OF NXP/SAMSUNG WITNESS GOBLE REGARDING MR. JOHNSON'S BIP ALLOCATION PROPOSAL?

A. Yes, I have.

Q. PLEASE COMMENT ON MR. GOBLE'S CRITICISM OF MR. JOHNSON'S BIP ALLOCATION PROPOSAL?

A. In general, I agree with Mr. Goble's criticism of the BIP methodology. He makes many of the same or similar points as I do in my testimony. Mr. Goble makes valid criticisms regarding specific details of witness Johnson's calculations. I have not addressed these details in my testimony because, from my perspective, the BIP allocation method is severely flawed on a theoretical basis and should not be seriously considered by the IHE.

Q. WHAT IS THE HISTORY OF USING THE A&E 4CP ALLOCATION METHOD IN THE 2012 RATE REVIEW?

A. In the 2012 study, the rate review test year was based on fiscal year 2009 operating results, which was a pre-nodal market test year. At the time, AE evaluated several production cost allocation approaches to determine the most appropriate method for the AE system. AE evaluated CP, A&E, and BIP allocation methods. At that time, AE had not conducted a comprehensive COS study in over 17 years. In 1997, the Austin City Council adopted a policy endorsing the use of the POD allocation method. Instead of the POD method, given uncertainty surrounding the proper allocation method to be used going forward, the BIP allocation method was developed and compared to the other methods. Based on comments and review by stakeholders engaged in the process, the A&E allocation method was adopted. When the 2012 study was filed at the PUC, the A&E method was modified to the A&E 4CP method, which was consistent with PUC precedent.

Q. DURING THE 2012 RATE REVIEW, DID THE RATES CONSULTANT RECOMMEND THE BIP ALLOCATION METHOD OVER OTHER ALLOCATION METHODS?

A. No. BIP was never recommended over other allocation methods. The BIP method was simply discussed and recommended to the rate review Public Involvement Committee ("PIC") as the *alternative* to the POD method. The PIC evaluated three allocation methods representing differing perspectives. The PIC reviewed the CP, A&E, and BIP allocation methods.

Q. HOW CAN YOU BE SURE OF THIS ASSERTION?

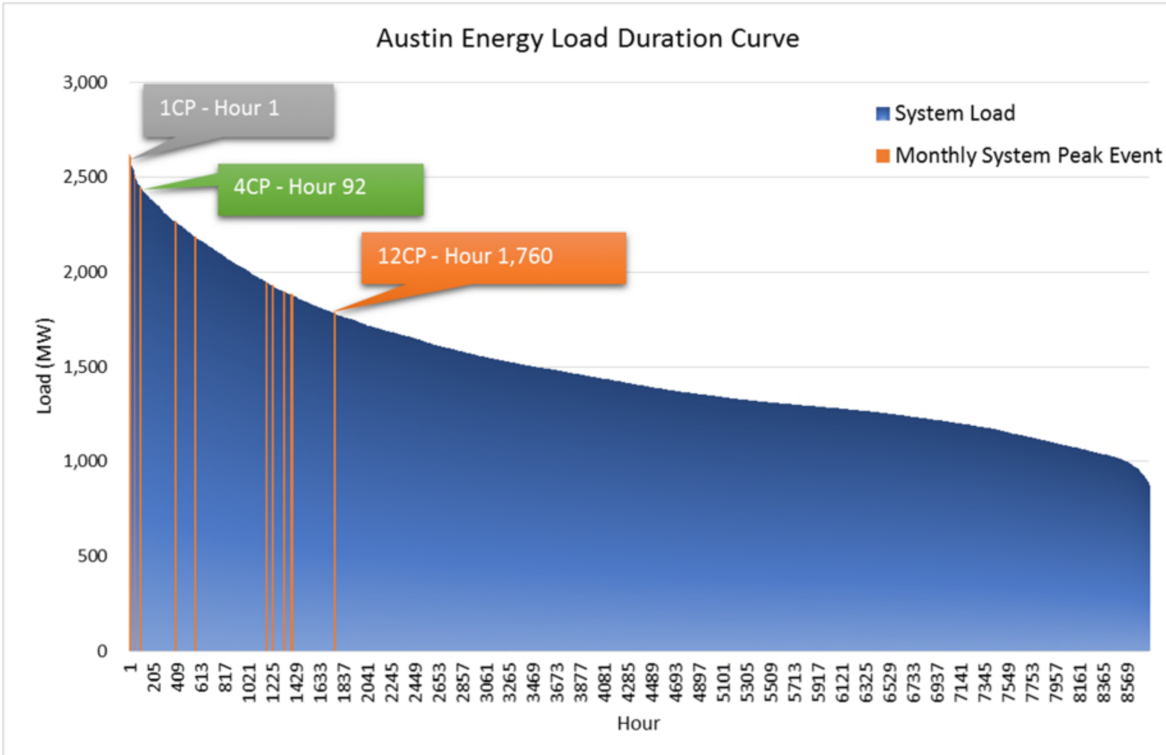
A. I was the rate consultant that worked with AE throughout the PIC process.

Q. WHY DID AE CHANGE THE ALLOCATION IN THE 2015 RFP FROM THE A&E 4CP METHOD TO THE 12CP METHOD?

A. In reviewing the proper production cost demand allocator for this proceeding, AE recognized that an effective capacity hedge was a key benefit to customers in the nodal market. Therefore, production fixed costs should be allocated on a CP basis. However, AE recognized that the benefit of the hedge was year-round and not just during the summer peak demand months. Accordingly, the previous demand allocator of A&E 4CP, which was essentially a 4CP allocator, was modified to a 12CP allocator.

Q. DOES THE 12CP ALLOCATOR APPROPRIATELY RECOGNIZE THE BENEFIT OF THE FINANCIAL HEDGE OVER THE YEAR?

A. Yes. The 12CP allocation method appropriately recognizes the benefit of the CUA financial hedge over a greater number of peak hours during the year. This is shown in the graph below.



For the test year, the graph shows the AE load duration curve. A load duration curve simply stacks AE's hourly peak demand from the highest hour to the lowest. The highest hour is the annual system peak, or 1CP. The graph also shows the 4CP and the 12CP. Under these alternative CP methods, monthly peak demands are identified and averaged. The 4CP includes the average monthly peaks of the four summer months, June through September. The 12CP method includes the average monthly peaks of all twelve months of the year.

Given this peak demand sampling methodology, the 1CP reflects the single highest hour in the year, the 4CP reflects a sampling of peak demands ranging from hour 1 through 92, and the 12CP reflects sampling of peak hours ranging from 1 through 1,760. Therefore, the 12CP effectively recognizes the capacity hedging value during the top 20% (1760/8760 = 20%) of the hours in the test year. Since customers benefit from CUA in periods outside of the four summer peak months, including peak periods outside of the summer season is an improvement over a 4CP allocation method.

Q. DATA FOUNDRY AND NXP/SAMSUNG RECOMMEND CONTINUED USE OF THE A&E 4CP ALLOCATION METHOD. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. The 12CP allocation approach is more equitable than the A&E 4CP method for the following reasons.

1. As discussed earlier in my testimony, AE generation assets are dispatched to the ERCOT market, not the AE load. Therefore, the A&E allocation philosophy, which considers an element of average demand equivalent to energy, does not align with the realities of AE's generation fleet operation. Without the 4CP adjustment to the calculation, the A&E method is an energy weighting method. Similar to the BIP, the A&E method is not appropriate in the nodal market.

2. With the 4CP adjustment, the A&E 4CP method is similar to a 4CP demand allocator. A 12CP allocation approach is superior to a 4CP allocation approach because the 12CP recognizes the hedging value provided to customers by AE's generation portfolio over a greater percentage of peak hours. A 4CP allocator only recognizes the top 1% (92/8760 = 1%) of hours compared to the top 20% of hours under the 12CP approach. Given the unpredictability of market prices throughout the year, the benefit is more appropriately recognized over a larger number of hours.

Q. WITNESS MCCOLLOUGH OF DATA FOUNDRY AND WITNESS GOBLE OF NXP/SAMSUNG TAKE ISSUE WITH AE'S USE OF THE ERCOT 12CP RATHER THAN THE AE SYSTEM 12CP. WHY DID AE USE THE TIMING OF THE ERCOT 12CP IN CALCULATING THE 12CP ALLOCATOR?

A. As mentioned previously in my testimony, AE generation resources are dispatched into the ERCOT market based on market pricing signals. CUA is an important metric which measures the ability of AE to take advantage of market pricing opportunities and provide an effective financial hedge to the benefit of customers. Given that market prices are generally higher during periods of high demand, and the value of CUA is the greatest during high price periods, the use of the ERCOT 12CP was determined to be an equitable measure of class demand responsivity.

Incidentally, the timing of AE's monthly system peaks is similar to that of ERCOT's peaks. Therefore, a change from one calculation method to another has a minimal impact on the COS results. This is shown in the following table based on the RFP as originally filed:

Cost of Service Indicated Rate Adjustment by Production Demand Allocation Method

Class	ERCOT 12CP	AE 12CP
Residential	11.7%	11.3%
Secondary Voltage < 10 kW	2.3%	2.5%
Secondary Voltage ≥ 10 < 300 kW	-15.3%	-14.9%
Secondary Voltage ≥ 300 kW	-8.1%	-7.7%
Primary Voltage < 3 MW	-8.9%	-8.7%
Primary Voltage ≥ 3 < 20 MW	-9.2%	-9.0%
Primary Voltage ≥ 20 MW	-3.1%	-3.0%
Transmission Voltage	-34.6%	-38.6%
Transmission Voltage ≥ 20 MW @ 85% LF	2.4%	2.6%
City-Owned Private Outdoor Lighting	30.9%	30.9%
Customer-Owned Non-Metered Lighting	5.8%	5.9%
Customer-Owned Metered Lighting	36.6%	30.1%

AE's use of the ERCOT 12CP simply recognizes that there may be cost benefits associated with load diversity in the market. A pricing signal that encourages customers to be off the ERCOT peak can provide long-term cost benefits on the production and transmission systems. Currently, AE pays for transmission service based on the utility's contribution to the ERCOT 4CP.

E. <u>Allocation of Distribution Costs</u>

Q. NXP/SAMSUNG WITNESS GOBLE RECOMMENDS USING THE 1NCP ALLOCATION METHOD FOR SUBSTATIONS, POLES, AND CONDUCTORS RATHER THAN 12NCP. DO YOU AGREE WITH HIS RECOMMENDATION?

A. I agree that NCP is the proper method for allocating distribution costs, but the use of 12NCP is more equitable than 1NCP. The NCP allocation method recognizes that distribution infrastructure is sized to meet the localized maximum demands on the system. These localized demands are best measured by class non-coincident peaks. Use of a 12NCP method recognizes that distribution capacity provides value to customers throughout the year not just during the peak hour or the summer peak months. Because the NCP calculation is done at the class level, off peak or seasonal customers may not be fully accounted for in a 1NCP calculation. A 12NCP calculation solves this problem. This is important as customers are becoming increasingly interested in distributed generation options and are able to shift load. From a cost allocation perspective, certain rate classes may be able to avoid a portion of distribution demand related costs by shifting demand during NCP periods. If the demand measure is a single hour (i.e., the 1NCP), the ability to shift and avoid cost responsibility is easier compared to a 12NCP method.

Additionally, the distribution system is spread across the geographic footprint of the system. The system is sized in consideration of localized demand that vary from area to area based on variations in the customer mix. These variations are better represented by a 12NCP allocator which takes into consideration the value of load diversity across the distribution system.

F. <u>Allocation of Customer Costs</u>

Q. ICA WITNESS JOHNSON RECOMMENDS ALLOCATION OF UNCOLLECTIBLE COSTS TO EACH RATE CLASS BASED ON THE CLASS REVENUE REQUIREMENT RATHER THAN THE DIRECT ASSIGNMENTS USED BY AE. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. Directly assigning the cost of uncollectible accounts to each rate class is a highly supportable and equitable method for recovering these costs from customer classes. The NARUC CAM, frequently relied upon by witness Johnson in his testimony, regarding uncollectible account expense, states:

> Customer-related costs (Accounts 901-917) include the cost of billing and collection, providing service information, and advertising and promotion of utility services. By their nature, it is difficult to determine the "cause" of these costs by any particular function of the utility's operation or by particular classes of their customers. An exception would be Account 904, Uncollectible Accounts. Many utilities monitor the uncollectible account levels by tariff schedule. Therefore, it may be appropriate to directly assign uncollectable accounts expense to specific customer classes.[12]

NARUC acknowledges that directly assigning these costs to each rate class is appropriate. Additionally, Mr. Johnson suggests that the direct assignment approach could result in volatile results by class. To test his concern, I compared the direct assignments associated with uncollectible accounts included in the prior rate case with that of the current RFP. Because commercial account designations have changed between studies, I compared the allocation of uncollectible accounts to the

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[12] Electric Utility Cost Allocation Manual, January 1992, p. 102.

residential class compared to other rate classes. My analysis is summarized in the following table:

Uncollectible Direct Allocator

Rate Case	Residential	All Other Classes
2009 - Previous Rate Case	90%	10%
2014 - Current Rate Case	91%	9%

The direct assignment comparisons show that the direct assignment method yields a stable result. This result is not surprising given the number of bills rendered and the underlying socioeconomic conditions of various rate classes.

Q. ICA WITNESS JOHNSON RECOMMENDS ALLOCATION OF METER EXPENSE USING A COMBINATION OF CUSTOMER AND DEMAND ALLOCATORS RATHER THAN BY A WEIGHTED METER ALLOCATOR USED BY AE. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. As discussed earlier in my testimony, meter expense is a customer related expense. AE has properly accounted for cost differentials between meters through the use of weighting factors used in the customer allocator. Any use of demand in the allocation of meter expense is unsupportable from a cost causation perspective, and unduly shifts metering expense from small to large demand customers.

Q. ICA WITNESS JOHNSON RECOMMENDS ALLOCATION OF METER READING COSTS BASED ON A WEIGHTED CUSTOMER ALLOCATOR RATHER THAN A NUMBER OF CUSTOMERS USED BY AE. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. AMI meters, including the supporting meter data management and billing systems, represent technologies that readily gather data and render bills. Metering configurations and rate complexity have no impact on the level of effort to read a meter. As such, it is appropriate to allocate the meter reading costs to each class based on the number of metered customers.

Q. ICA WITNESS JOHNSON RECOMMENDS ALLOCATION OF MARKETING AND ADVERTISING COSTS IN FERC ACCOUNTS 908-910 BASED ON WEIGHTED ALLOCATORS REPRESENTING 50% CLASS REVENUE REQUIREMENT AND 50% NUMBER OF CUSTOMER RATHER THAN 100% ON NUMBER OF CUSTOMERS AS USED BY AE. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. In his criticism of AE's allocation treatment related to marketing and advertising expense, witness Johnson quotes the NARUC CAM pertaining to Sales Expenses in FERC Accounts 911-917. Given that witness Johnson is recommending changes to FERC Accounts 908-910, his quotation is not applicable. Pertaining to Customer and Information Expenses in FERC Accounts 906-910, the NARUC CAM states:

> These accounts include the costs of encouraging safe and efficient use of the utility's service. Except for conservation and load management, these costs are classified as customer related. Emphasis is placed upon the cost of responding to customer inquiries and preparing billing inserts.[13]

NARUC appears to agree with AE's cost allocation approach for these expenses. The best measure of customer inquiries and billing related activities is the number of customers on the system. Allocation based on metered customers is a fair and reasonable approach of assigning these costs to each class.

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[13] *Id*. at 103.

IV. RATE DESIGN

A. Revenue Adjustment

Q. PLEASE SUMMARIZE RATE DESIGN ISSUES RAISED BY THE VARIOUS INTERVENING PARTIES.

A. Rate design issues raised by intervenors include:

1. **Proper Allocation of the Revenue Decrease –** The ICA, Data Foundry, and NXP/Samsung offer different proposals regarding the allocation of the revenue decrease to each rate class. Proposals range from moving to cost-based rates per COS results (NXP/Samsung) to ignoring COS results entirely (ICA). I will explain why AE's revenue decrease proposal is reasonable and should be adopted by the City Council.

2. **Proper Use of the Billing Adjustment Factor –** NXP/Samsung witness Goble recommends that billing adjustments used in the development of rate design, and critical to the proof of revenue calculation, be disallowed in the rate calculation. I will explain why this adjustment factor is needed and why it is proper and reasonable to include such an adjustment in the rate calculation.

Q. DO YOU AGREE WITH ICA WITNESS JOHNSON'S REVENUE DISTRIBUTION RECOMMENDATION?

A. No. Witness Johnson contends that revenue decreases should be distributed broadly among classes instead of along COS guidelines, and proposes that revenue decreases be allocated based on class share of kWh consumption. This approach is arbitrary and ignores COS results. Under this approach, classes that are currently under-collecting compared to their COS would be moved even further away from full cost recovery, thus creating larger interclass subsidy issues for AE to address in the future. It is sound rate making policy to move toward COS, rather than away from COS. AE witness Mark Dombroski's rebuttal testimony provides additional reasons for rejecting Mr. Johnson's recommendation.

Q. DO YOU AGREE WITH ICA WITNESS JOHNSON'S ASSERTION THAT BECAUSE AE IS PUBLICALLY OWNED, EXCESS REVENUES SHOULD BE SHARED BROADLY AMONG DIFFERENT TYPES OF CUSTOMERS?

A. No. In theory, excess revenues or return would be generated equally from each rate class. This result would be realized if rates were set at COS. However, for a variety of reasons, this is almost never the case due to cross-subsidization between classes, changes in costs, and changes in class load characteristics. To adjust rates to improve the equity of class return contribution, the COS analysis must be taken into consideration. Classes well below COS do not contribute any excess revenues and should not be allocated a portion of the revenue reduction. An over-collection of base rate revenue is a COS and rate design issue that should be addressed using COS and rate design principals.

Q. DO YOU KNOW OF ANY RATE CASES DECIDED BY THE PUC IN THE LAST 10 YEARS THAT PROVIDE PRECEDENT FOR ICA WITNESS JOHNSON'S CONTENTION THAT REVENUE DECREASES IN GENERAL SHOULD BE DISTRIBUTED BROADLY?

A. No. My review of rate cases for vertically integrated utilities filed at the PUC since 2007 found only one case decided by the PUC that resulted in an overall reduction in revenue requirement greater than $4,000,000 – Docket No. 43695. In that case, the PUC decided that all rates were to be set based on COS.[14] The resulting revenue distribution resulted in rate increases to general residential, large general service,

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[14] *Application of Southwestern Public Service Company for Authority to Change Rates,* Docket No. 43695, Finding of Fact No. 337C (Dec. 18, 2015).

lighting, small school and municipal rate classes ranging from 2% to 24%, and decreases to all other classes based on the COS results.[15]

Q. DO YOU AGREE WITH DATA FOUNDRY/AUSTIN CHAMBER WITNESS MCCOLLOUGH'S REVENUE DISTRIBUTION RECOMMENDATION THAT REVENUE DISTRIBUTIONS SHOULD BE BASED ON PROPOSED RATES INCLUDING PASS THROUGHS?

A. No, for the following reasons:

1. Data Foundry/Austin Chamber recommends that revenue distribution should be based on proposed rates including Rate-Year pass-through rates rather than Test-Year pass-through rates. Pass-through rates are designed to recover costs with no consideration for indirect costs or margins. Over time, revenues from pass-through rates equal costs, so pass-through rates reflect COS and do not generate excess revenues. Excess revenues are generated solely from base rates. Therefore, pass-through rate revenue should be excluded from any revenue distribution calculation.

2. Data Foundry/Austin Chamber recommends that classes under-recovering COS be given a 2% increase. The classes most impacted by this provision would be the Residential and Secondary Voltage <10kW classes. Given rate design objectives and gradualism objectives for these rate classes, AE has chosen to address systematic concerns with the current rate design by removing seasonal rates and flattening of tiered pricing structures (tiers are applicable to the residential class only), which could result in bill increases for some customers.[16] City Council policy suggests gradual approaches to rate changes. Considering that AE is anticipating an overall revenue requirement reduction and established policies of gradualism, it is appropriate to first address the current rate design issues with a goal of no class rate revenue increases and then address total revenue recovery issues in future years as proposed.[17]

3. Data Foundry/Austin Chamber recommends that all classes that are currently above COS be moved proportionally to COS. Arbitrarily reducing rates proportionally to COS can result in an illogical progression of tariffs. In

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[15] Docket No. 43695, Final Order Attachment C at 77.

[16] Tariff Package at 144 (6.5.2) and 157 (6.6.5).

[17] *Id.* at 176

designing rates, AE takes into account both the COS results and the logical progression of rate tariffs.[18]

Q. DO YOU AGREE WITH NXP/SAMSUNG'S COMMENTS OR RECOMMENDATIONS WITH RESPECT TO AE'S REVENUE DISTRIBUTION?

A. No. Witness Goble states that all classes should be directly brought to full cost recovery. For residential customers, this would result in a base revenue increase of over 20%. This position does not properly consider the City Council's affordability goals. As stated previously in response to Data Foundry/Austin Chamber's position on this matter, AE has chosen to address systematic concerns with the current rate design by removing seasonal rates and adjusting tiered pricing structures, which could increase bills for some customers. Council policy suggests gradual approaches to rate changes. Considering that AE anticipates an overall revenue requirement reduction and established policies of gradualism, it is appropriate to first address the current rate design issues with a goal of no class rate revenue increases, and then address total revenue recovery issues at a future date, as proposed.

B. <u>Billing Adjustment Factor</u>

Q. WHAT WAS THE INTERVENOR TESTIMONY ON THE BILLING ADJUSTMENT FACTOR?

A. NXP/Samsung witness Gary Goble criticized AE for not calculating a billing adjustment factor on a class basis and, instead, using a system-wide billing adjustment factor.

[18] *Id*. at 130.

Q. WHAT IS THE BILLING ADJUSTMENT FACTOR?

A. The billing adjustment factor accounts for the difference between what AE actually booked as revenue and what it should have booked based on the billing determinants (e.g., number of customers, kW and kWh) and the prevailing rates. This is a common adjustment and accounts for various factors, including errors in prior billings, partial bills, and estimated meter reads.

Q. WOULD A CLASS-BY-CLASS BILLING ADJUSTMENT FACTOR BE PREFERABLE?

A. Yes, but AE is not able to calculate reliable, class-specific billing adjustment factors at this time. Contrary to Mr. Goble's suggestion that the data by customer class was purposefully hidden by AE, the reality is that reliable data is not currently available. AE's systems do not allow for accurate base revenue reporting by customer class, in part due to the need to allocate revenues from certain customers on long-term contracts. AE may be able to accurately identify base revenue by customer class in the future and, if so, this could be incorporated into future studies. But currently, there is not a reliable means to identify the billing adjustment factor by customer class.

Q. IS IT APPROPRIATE TO DISALLOW THE BILLING ADJUSTMENT FACTOR BECAUSE IT CANNOT BE CALCULATED FOR EACH INDIVIDUAL CUSTOMER CLASS?

A. No. This type of adjustment is common in electric rate studies and should not be disallowed altogether due to a lack of data to calculate class-specific billing adjustment factors. The system-wide billing adjustment factor used by AE is appropriate based on the data currently available.

V. CONCLUSION

Q. MR. MANCINELLI, DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

NewGen Strategies & Solutions

Joseph Mancinelli
General Manager and President, Energy Practice
jmancinelli@newgenstrategies.net

Joseph Mancinelli has over 28 years of experience as a utility consultant serving the public utility industry; he is President and General Manager of NewGen Strategies and Solutions, LLC's, Energy Practice. NewGen offers a wide range of management, planning and economic services to clients in public power. His direct experience includes the management of high performance teams, strategic and business planning, performance management, economic analyses, asset valuation, revenue bond financing and cost of service and rate design analyses in the roles of project manager, lead analyst and expert witness. He has worked closely with public utility commissions, senior management teams, utility boards, city councils, attorneys, and end-users. He has designed and taught numerous classes on cost of service and rate design methodology, including a cost of service and rate design course for Electric Utility Consultants, Inc. He regularly speaks at conferences across the country.

EDUCATION

- Master of Business Administration in Finance, University of Colorado
- Bachelor of Science in Geophysical Engineering, Colorado School of Mines

KEY EXPERTISE

- Expert Witness and Litigation Support
- Cost of Service and Rate Design
- Asset Valuation
- Economic Analysis
- Strategic Planning
- Performance Management
- Revenue Bond Financing

RELEVANT EXPERIENCE

Cost of Service and Rate Design – Electric

Mr. Mancinelli has participated in numerous retail rate studies for electric utilities as summarized below:

- **Cost of Service and Rate Design Study – Tri-State Generation and Transmission Cooperative.** Mr. Mancinelli led a comprehensive independent review of Tri-State's cost of service and rate design practices. The study involved a detailed assessment of Tri-State's cost of service and the appropriate rate design in an effort to resolve rate disputes between its Members. NewGen was initially hired by a Member Rates Committee (Committee) appointed by the Tri-State Generation and Transmission Cooperative's Board of Directors (Board) to conduct a comprehensive cost of service study and support the Committee with rate design efforts. Tri-State is a Generation and Transmission Cooperative serving 44 members across Colorado, New Mexico, Nebraska and Wyoming. Services include development of historical and projected Test Year revenue requirements and the development of detailed and dynamic cost of service and rate design models. These models enable the Committee to evaluate alternative cost allocation methods and rate structures. In addition to conducting analyses, NewGen supported the Committee with advice, training, reports, presentations and other pertinent industry information. The Committee unanimously submitted to the Board a recommended cost of service methodology and rate design. Upon completion of the Committee work, Tri-State retained NewGen to work

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with the Board throughout the rate deliberation and approval process. NewGen supported the Board with training, advice and recommendations. Also, NewGen worked with Tri-State staff in the development and presentation of study results to a wide variety of stakeholder across the 44 member systems. Again, upon completion of a three month Board evaluation process, the Committee's recommended cost of service and rate design was unanimously approved by the Board.

- **Utility Services Study - U.S. Army; Huntsville, AL.** Mr. Mancinelli was project manager for numerous studies for the United States (U.S.) Army which evaluated and investigated electric consumption, contracts, potential upgrades, and distributed generation opportunities at active duty and reserve bases across the U.S. in an effort to reduce costs and support NetZero energy goals. NewGen supported the Army's goals including the development of a comprehensive electric utility contract and tariff database for the bases, evaluating nine reserve bases' energy consumption and cost reduction opportunities, and following up on prior studies to evaluate past upgrade benefits. Specific tasks included evaluating energy consumption profiles, billing accuracy, base operations, contract terms, rate options, asset / facilities upgrades (e.g. energy efficiency/demand response), distributed generation options, and tenant billing recovery. The result of the project provided recommendations tailored to each base to optimize rate options, existing/planned distributed renewable generation, and facility upgrades to reduce costs and support NetZero goals.

- **Unbundled Cost of Service and Rate Design – Lubbock Power and Light, Lubbock, Texas**. Since its inception, Lubbock Power and Light (LP&L) competed head to head with Xcel Energy for electric customers within the City's service territory. Electric rates were established on a purely competitive basis in order to attract and retain customers. However, in 2009, LP&L purchased the distribution system from Excel and become a monopoly electric service provider. Given this change in the business operations. LP&L retained NewGen to perform the utilities first ever cost of service and rate design study. Mr. Mancinelli led the effort which included staff training on cost of service concepts, development of sophisticated cost of service and rate design tools, education of Utilities Board and City Council through multiple workshops and support at public meetings.

- **Unbundled Cost of Service and Rate Design – Austin Energy; Austin, Texas**. Mr. Mancinelli managed a comprehensive cost of service and rate design study for Austin Energy which included the determination of system revenue requirements, an unbundled cost of service analysis, rate design, and support of an extensive public involvement process. The study addressed many challenges faced by AE such as pricing strategies to support system efficiency, deployment of new technologies and active support of environmental stewardship.

  Rate design took into consideration fixed cost recovery strategies in support of AE's aggressive energy efficiency and distributed solar goals. Additionally, rates were unbundled and various pass-through mechanisms were employed to manage the risk associated with volatile and unpredictable costs associated with ERCOT regulatory requirements. Cost of Service and rate design models were developed with to support the rate case filing requirements. Testimony supporting the study was prepared and presented to the Public Utility Commission of Texas.

- **Evaluate Cooperative Wholesale Power Rate and Structure – Delta Montrose Electric Association, Colorado**. Mr. Mancinelli provided a high level review and evaluation of a large wholesale power electric cooperative's rates and structural rate changes to its members. The Generation and Transmission electric cooperative provides power to 44 distribution members across several states including a wide variety of member loads (e.g. agricultural/irrigation driven member loads vs. high load factor large commercial members). The G&T coop implemented a new energy-only, seasonal TOU rate. The review included evaluating the impacts of the new wholesale seasonal and TOU pricing structure on DMEA's current system, potential impacts to higher load factor customers and the likely long-term impacts to the member and cooperative's system load profiles. Tasks included evaluating pros/cons and the longer term impacts of switching from a fixed and variable rate structure to an energy only rate, new pricing signals and potential for load factor degradation and identified the likely 'break-even' system load factor from the existing rate and the new rate.

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- **Cost of Service, Rate Making and Customer Rate Impacts – United Power Electric Cooperative; Brighton, Colorado**. In the role of Project Manager, Mr. Mancinelli led NewGen team members in updating United Power's existing cost of service analysis and modified the analysis as necessary to reflect the change in the wholesale rate structure. Tri-State proposed a dramatic shift in its wholesale pricing structure shifting from a demand and energy rate to an all energy rate structure. This pricing change resulted in a shifting of costs from low load factor to high load factor customers. The project team evaluated multiple cost allocation and pricing scenarios including the development of a five-year rate design phase in strategy.
- **Rate Advisory Services – Fort Collins Utilities; Fort Collins, Colorado**. Cost of service and rate design in support for the electric, water, wastewater utilities. Mr. Mancinelli assisted the electric utility in the development of a rate design philosophy which serves as a guide for policy makers in the rate setting process. Additionally, rates were redesigned and implemented for the residential and small commercial customer classes to improve conservation and efficiency signals. Also, Mr. Mancinelli assisted the electric utility in a preliminary evaluation of TOU and electric vehicle rates in anticipation of Fort Collins Utilities deployment of smart meters during the 2012 -2013 time period.
- **Unbundled Cost of Service Study – City Public Service (CPS) of San Antonio; San Antonio, Texas**. Worked closely with the CPS staff in developing one of the first comprehensive unbundling studies in the industry. The study has served has a model for future unbundling studies that are now common place today.
- **Unbundled Cost of Service and Rate Design – New Braunfels Utilities; New Braunfels, Texas**. Developed numerous cost of service and rate design scenarios that considered various power supply and commercial class options.
- **Competitive Rate Analysis, Cost of Service, and Rate Design – GEUS; Greenville, Texas**. Performed multiple cost of service and rate design studies supporting utilities financial requirements in light of extremely competitive rate environment in Texas, particularly with the neighboring investor-owned utility.
- **Unbundled Cost of Service and Rate Design – Brownsville Public Utilities Board (BPUB); Brownsville, Texas**. Assisted BPUB in developing unbundled rates in preparation for retail competition in Texas. The study included unbundled cost of service analysis, competitive rate analysis, and rate design. Numerous rate and cost of service analyses have been performed for this client.
- **Unbundled Cost of Service and Rate Design – Bryan Texas Utilities (BTU); Bryan, Texas**. Assisted BTU in developing unbundled rates in preparation for retail competition in Texas. The study included unbundled cost of service analysis and rate design. Numerous rate and cost of service analyses have been performed for this client.
- **Competitive Fuel Assessment – City of Garland Power and Light (GP&L), Garland, Texas**. GP&L's direct competitor is neighboring TXU. To understand the implications of a changing power market and fuel prices on the competitive relationships between each utilities retail rates, GP&L retained our firm to perform a competitive assessment. The competitive assessment evaluated the underlying cost structures of both utilities and the associated cost of service for certain rate classes.
- **Unbundled Cost of Service and Rate Design – Weatherford Municipal Utilities, Weatherford, Texas**. Performed a retail unbundling study that unbundled utility costs based on services currently provided to customers. Developed an integrated pro forma model of each of the three utility systems on a stand-alone basis that determined the City's revenue and capital requirements for each utility over a projected five-year period. Numerous rate and cost of service analyses have been performed for this client.
- **Rate Case Management and Expert Testimony – Plains Electric Generation and Transmission Cooperative, Inc.** Mr. Mancinelli supported Plains Generation and Transmission Cooperative (Plains) in numerous regulatory proceedings and a comprehensive rate case over the period of 1997 to 2000. At that time, Plains was in financial distress and was seeking rate relief from the New Mexico Public Utilities Commission (NMPUC). Plains primary

asset included the Escalante Power Station, a 250 MW base load coal unit. He supported Plain's COS and rate recommendations, which were successfully adopted by the NMPUC. Eventually, in 2000, Plains merged with Tri-State Generation and Transmission Cooperative. In the interim, on behalf of Plains, Mr. Mancinelli served as the primary rates and regulatory analyst for the generation and transmission cooperative during the transition period. Mr. Mancinelli acted in this role in a significant capacity from 1998 through 2000.

- **Financial Restructuring and Related Services – Deseret Power Cooperative, Utah**. Over a several year period, Mr. Mancinelli assisted Deseret Power Cooperative (Deseret) on a variety of assignments associated with the restructuring of debt obligations associated with Deseret generation assets. Deseret's most significant assets include a 25 percent ownership share of the Hunter coal unit, full ownership of the Bonanza coal-fired generation station, a bituminous coal mine (Deserado Mine), and a coal transportation system. He supported Deseret with the development and evaluation of business plans that looked at alternative paths forward for the wholesale power supplier. Options evaluated ranged from selling all or part of the system to third parties, to restructuring Deseret debt obligations and continuing to operate in an autonomous fashion. Business plans were supported with a long-term financial forecast that projected the utilities fixed and variable cost obligations, cash flows available for credit obligations, and the impact on member rates. He interacted heavily with Deseret members and creditors. Upon completion of the evaluation process, Deseret successfully restructured its debt and continues to operate today in a highly efficient and effective manner.

  Additional services provide to Deseret included COS and rate design associated with large industrial and mining load service by Deseret members. Rate design took into consideration the marginal cost of generation and creative rate design options were developed to retain large loads threatening to leave the system.

  Other services included an appraisal of the Bonanza Generation Station and the Deserado Mine for property tax purposes. Appraisals adhered to the criteria set forth by the American Society of Appraisers of which a key indicator of value is a long-term discounted cash flow analysis of power station and mine operations.

- **Utility Acquisition – Tri-State Generation and Transmission; Westminster, Colorado.** Performed an economic evaluation of an acquisition of customers to assess asset value in support of a competitive bid process.

Expert Witness and Litigation Support

Mr. Mancinelli has offered expert testimony regarding cost of service rate design and ratemaking issues before state and local regulatory bodies and courts. He has national experience providing litigation support regarding ratemaking matters at wholesale and retail levels in Alaska, Colorado, Guam, Michigan, New Mexico, Nevada, Texas, and Utah.

- **Expert Testimony – Northern Indiana Public Service Company, Cause No. 44688**. Expert testimony discussing the benefits of adding additional interruptible capacity on the system and the proper allocation of generation costs given the systems unique characteristics.

- **Expert Testimony – Bryan Texas Utilities, Docket No. 44467**. Expert testimony in support of BTU's interim transmission cost of service filing before the Public Utility Commission of Texas. Testimony determined transmission function revenue requirement in consideration of significant recent capital improvements completed by BTU.

- **Expert Testimony – Lower Colorado River Authority, Cause No. 121-001-B.** Mr. Mancinelli testified in a wholesale rate dispute between the City of Kerrville, acting by and through Kerrville Public Utility Board and the Lower Colorado River Authority. After the Municipal utility decided not to renew and extend their long-term power contracts with LCRA, and LCRA changed some key rate policies that impacted the utility, the parties' disagreements evolved into a contract rate dispute in District Court of Kerr Count. Key issues of the dispute included migrating from a demand/energy wholesale rate structure to an all energy wholesale rate structure, non-uniform application of rates between the various LCRA customers and retention of excess earnings.

- **Expert Testimony – GEUS; Texas Public Utilities Commission; Docket No. 42581.** Testified on transmission system revenue requirement, cost of service, and return on rate base issues. Successfully achieved a 17 percent increase in clients transmission revenue requirement reflecting a 7 percent increase in the wholesale transmission rate.

- **Expert Testimony – Bryan Texas Utilities, Docket No. 41920**. Expert testimony in support of BTU's interim transmission cost of service filing before the Public Utility Commission of Texas. Testimony determined transmission function revenue requirement in consideration of significant recent capital improvements completed by BTU.

- **Expert Testimony – Lower Colorado River Authority, Cause No. D-1GN-12-002156**. Mr. Mancinelli prepared expert witness report quantifying damages incurred by customers associated with LCRA wholesale rate practices. Three electric cooperatives, Central Texas Electric Cooperative, Inc., San Bernard Electric Cooperative, Inc., and Fayette Electric Cooperative, Inc. (Cooperatives), were long-standing wholesale power customers of the Lower Colorado River Authority (LCRA). After the Cooperatives decided not to renew and extend their long-term power contracts with LCRA, and LCRA changed some key rate policies that impacted the Cooperatives, the parties' disagreements evolved into a contract rate dispute in Travis County, Texas District Court. Key issues of the dispute included migrating from a demand/energy wholesale rate structure to an all energy wholesale rate structure, non-uniform application of rates between the various LCRA customers and retention of excess earnings.

- **Expert Testimony – Austin Energy; Docket No. 40627**. Austin Energy serves a large number of customers outside the City limits, and therefore, is subject to the regulatory authority of the Public Utilities Commission of Texas (PUCT) if so petitioned by outside the city customers. In the fall of 2012, in conjunction with the City Council approval of retail rates, outside the city customers petitioned the PUCT to review recently adopted rates. In support of AE's rate petition, Mr. Mancinelli provided comprehensive expert testimony related to Austin Energy system revenue requirements, cost of service and rate design. The case was successfully settled in AE's favor in the spring of 2013.

- **Expert Testimony – Guam Power Authority; Docket No. 11-09**. Provided regulatory advice in support of a comprehensive rate case filed before the Guam Public Utilities Commission. Services provided included rate case strategy, coordination and critique of testimony developed by GPA staff and other expert witnesses and development of testimony in support of the GPA revenue requirement.

- **Expert Testimony – Rocky Mountain Power; Docket Nos. 08-035-38 and 09-035-23**. Rate case support related to Docket 08-035-38 and filed testimony in Docket 09-035-23. Testified on behalf of the Utah Division of Public Utilities, the regulatory arm of the Utah Public Utilities Commission with respect to Rocky Mountain Power's cost of service analysis. Review included cost classification, allocation methodology, model design, rate design, and associated customer impacts.

- **Expert Testimony – GEUS; Texas Public Utilities Commission; Docket No. 37180**. Testified on revenue requirement, cost of service, and return on rate base issues. Successfully achieved a 39 percent increase in clients transmission cost of service.

- **Expert Testimony – Chugach Electric and Homer Electric Association; Regulatory Commission of Alaska; Docket No. U-06-134**. Testified on revenue requirement, cost of service, class, and TIER issues.

- **Litigation Support – Brownsville Public Utilities Board; Docket No. 32905; Filing of Transmission Cost of Service before the Texas Public Utilities Commission**. Developed testimony on behalf of the Brownsville Public Utilities Board in support of transmission costs to be included in the Electric Reliability Council of Texas transmission postage stamp rate calculation.

- **Expert Testimony – Application of Sierra Pacific Power Company with respect to retail rates; Docket No. 05-10003**. Provided testimony on behalf of the Nevada Resort Association in support of reductions to the Sierra Pacific revenue requirement and modifications to the Sierra Pacific marginal cost of service study.

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- **Litigation Support – Lamar Light and Power versus Colorado Aquature**. Provided testimony on behalf of Lamar Light and Power in dispute over the economic benefits and impact on rates of mothballing a gas-steam generation station.
- **Litigation Support – Xcel Energy; Docket Number 02S – 315 EG; The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado Advice Letter No. 1373 – Electric, Advice Letter No. 593 – Gas, and Advice Letter No. 80 – Steam**. Intervened on behalf of the City and County of Denver.
- **Litigation Support – AEP Texas Central Company; application of AEP Texas Central Company for authority to change rates; PUC Docket No. 28840**. Evaluated impact of proposed rates and cost of service on the retail ratepayers of numerous Texas cities.
- **Litigation Support – GEUS; Greenville, Texas; Case Number 25591**. Prepared analysis in support of settlement negotiations with Texas Public Utilities Commission.
- **Litigation Support – Brownsville Public Utilities Board; Texas**. Supported legal team intervention in numerous rate proceedings at the Public Utility Commission of Texas related to Texas deregulation Senate Bill #7.
- **Expert Testimony – Brownsville Public Utilities Board; Texas; Texas Water Commission; Docket No. 9013-M**. Water System Revenue Requirement and Allocated Cost of Service for a Special Contract Customer.
- **Expert Testimony – GEUS; Greenville, Texas; Texas Public Utility Commission**. Compliance with Substantive Rule 23.67: Unbundled Transmission Cost of Service.
- **Expert Testimony and Litigation Support – The City and County of Denver; United States District Court for the District of Colorado; Civil Action No. 96-D-2968.** Radium Storage Fees.
- **Expert Testimony – Plains Electric Generation and Transmission Cooperative, Inc.; New Mexico Public Utilities Commission; Docket No. 2797**. Electric System Cost of Service and Rate Study.
- **Expert Testimony – Traverse City Light and Power and Michigan Public Service Commission; Case Number U-13716**. Prepared expert testimony on evaluating cost basis for proposed large resort service tax.
- **Expert Testimony – Traverse City Light and Power and City of Traverse; Case Number U-12844 and U-13071**. Testified against damages associated with loss of large retail load to a competing utility.

Workshops and Presentations

Mr. Mancinelli has given numerous presentations and participated in training and workshops in several states. These activities have focused on cost of service, ratemaking, and competitive issues.

- **American Public Power Association**
  - Costs and Benefits of Generation Resources
  - Innovative Rates and Rate Riders for Key Accounts
  - Including Risk Management in the Key Account Function
  - Advanced Rate Making Concepts for Publicly Owned Electric Systems
  - Retail Rate Design for Publicly Owned Electric Systems
- **Electric Utility Consultants, Inc.**
  - Witness Preparation. A two day training program pertaining to preparing and serving as an expert during the rate case process and learning how to be an effective witness during a rate case hearing
  - Introduction to Cost of Service Concepts and Techniques for Electric Utilities.

  - Introduction to Rate Design for Electric Utilities. A two day course taught semi-annually
- **Texas Public Power Association**
  - Establishing Effective Financial Policies for Your Utility
  - Developing Rate Design Strategies and Financial Policies for Your Utility
  - Contracting with Retail Customers
- **New Mexico Rural Electric Association –** Unbundling for Competition
- **Utah Association of Municipal Power –** Electric Rate Unbundling
- **Utah Rural Electric Association –** Electric Rate Unbundling
- **New Hampshire Electric Cooperative –** Two day strategy and training program pertaining to rate design and cost of service

Record of Testimony Submitted by Joseph A. Mancinelli

Utility	Proceeding	Subject	Before	Client	Date
1. Northern Indiana Public Service Company	Cause No. 44688	Interruptible Demand Credits and Cost of Service	Indiana Utility Regulatory Commission	United States Steel	2016
2. Bryan Texas Utilities	Docket No. 44467	Application of Bryan Texas Utilities for Interim Update of Wholesale Transmission Rates Pursuant to Substantive Rule 25.192(g)(1)	Public Utility Commission of Texas	Bryan Texas Utilities	2015
3. Lower Colorado River Authority	Cause No. 121-001-B	Damages Associated with Wholesale Pricing Practices	District Court of Kerr County, Texas (198th Judicial District)	City of Kerrville, acting by and through Kerrville Public Utility Board	2014-2015
4. GEUS	Docket No. 42581	Application to Change Rates for Wholesale Transmission Service	Public Utility Commission of Texas	GEUS	2014
5. Bryan Texas Utilities	Docket No. 41920	Application of Bryan Texas Utilities for Interim Update of Wholesale Transmission Rates Pursuant to Substantive Rule 25.192(g)(1)	Public Utility Commission of Texas	Bryan Texas Utilities	2013
6. Lower Colorado River Authority	Cause No. D-1GN-12-002156	Damages Associated with Wholesale Pricing Practices	District Court of Travis County, Texas (261st Judicial District)	Central Texas Electric Cooperative, Inc., Fayette Electric Cooperative, Inc., and San Bernard Electric Cooperative, Inc.	2013-2014
7. Austin Energy	SOAH Docket No. 473-13-0935 PUC Docket No. 40627	Petition by Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-055	Public Utility Commission of Texas	On behalf of the City of Austin D/B/A Austin Energy	2013
8. Guam Power Authority	Docket No. 11-09	Support of Comprehensive Rate Case	Guam Public Utilities Commission	Guam Power Authority	2012
9. Brownsville Public Utilities Board	Docket No. 38556	Application to Change Rates for Wholesale Transmission Service	Public Utility Commission of Texas	Brownsville Public Utilities Board	2010
10. Rocky Mountain Power	Docket No. 09-035-23	Testified regarding Rocky Mountain Power's Cost of Service Analysis	Utah Public Utilities Commission	Utah Division of Public Utilities	2009
11. GEUS	Docket No. 37180	Support Application to Change Rates for Wholesale Transmission Service	Public Utility Commission of Texas	GEUS	2009
12. Chugach Electric	Docket No. U-06-134	Revenue Requirement, Cost of Service Allocation, Class, and TIER Issues	Regulatory Commission of Alaska	Alaska Electric & Energy Coop/Homer Electric Association	2007

Utility	Proceeding	Subject	Before	Client	Date
13. Sierra Pacific Power Company	Docket No. 05-10003	In Support of Reductions to Sierra Pacific Revenue Requirement and Modification to the Sierra Pacific Marginal Cost of Service Study	Public Utilities Commission of Nevada	Nevada Resort Association	2006
14. Brownsville Public Utilities Board	Docket No. 32905	Testified in Support of Transmission Costs	Texas Public Utilities Commission	Brownsville Public Utilities Board	2006
15. Cherryland Electric Cooperative vs. Traverse City Light & Power	Case No. U-13716	Evaluating Cost Basis for Proposed Large Resort Service Tax	Michigan Public Service Commission	Traverse City Light & Power	2004
16. Cherryland Electric Cooperative vs. Traverse City Light & Power	Case Nos. U-12844 and U-13071	Testified Against Damages Associated with Loss of Large Retail Load to Competing Utility	Michigan Public Service Commission	Traverse City Light & Power	2002
17. Plains Electric Generation & Transmission Cooperative	Docket No. 2797	Electric System Cost of Service and Rate Study	New Mexico Public Utilities Commission	Plains Electric Generation and Transmission Cooperative	1998
18. Environmental Protection Agency	Civil Action 96-D-2698	Radium Storage Fees	United States District Court of the District of Colorado	City and County of Denver	1997
19. Greenville Electric Utility System	Docket No. 15812	Unbundled Transmission Cost of Service/Transmission Rate Filing Compliance with Substantive Rule 23.67	Public Utility Commission of Texas	Greenville Electric Utility System	1996
20. El Jardin Water Supply Corporation	Docket No. 9013-M	Water System Revenue Requirement and Allocated Cost of Service Study	Texas Natural Resources Commission	Public Utilities Board of Brownsville, Texas	1992-1993

Austin Energy's Response to ICA's 7th RFI

ICA 7-3 Re: WP-E-5.1. Please explain why new service connection revenues are classified distribution rather than customer. Does this fee recover incremental costs for new meters and service drops?

ANSWER:

The New Service Connections fee on WP E-5.1 are fees collected for initiating service and reconnecting after failure to pay. Because this service is associated with the distribution of power to the customer it has been functionalized to the distribution function. These fees do not recover the incremental cost for new meters and service drops. Please reference section 5.2.3 of Austin Energy's report to council, starting on Bates stamp 111, for a discussion on the distribution function.

Prepared by: MM
Sponsored by: Mark Dombroski

ICA 1-20. With respect to smart meters installed for each customer class, what percentage are capable of interval data recording? What percentage by class are actually utilized to provide time interval measurement?

ANSWER:

Thirty percent of our residential smart meters are currently capable of interval data recording, with 10% currently sending interval data through our Advanced Metering Infrastructure head end system. This number is anticipated to grow to 100% capable and 100% provisioning of interval data to the utility within the next 5 years.

One hundred percent of our C&I meters are capable of collecting interval data, with 10% currently providing that data back to the utility. We anticipate that number to likewise rise to 100% within the next 5 years.

Prepared by: BK
Sponsored by: Elaina Ball