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AUSTIN ENERGY 2022 BASE RATE REVIEW	§	**BEFORE THE CITY OF AUSTIN IMPARTIAL HEARING EXAMINER**
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POSITION STATEMENT AND EXHIBITS

OF

NXP USA, INC.

JUNE 22, 2022

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EXECUTIVE SUMMARY

NXP USA, Inc. ("NXP")[1] presents its positions through the testimony of two experienced utility rate experts, James W. Daniel and Chuck Loy. They present their credentials within their respective portions of the Statement of Position. Mr. Daniel and Mr. Loy have extensively analyzed the Austin Energy base rate filing package, as well as discovery responses and other relevant information, in formulating their analysis.

Based on their analysis, NXP offers these conclusions and makes the following recommendations:

(1) AE has incorrectly allocated its production demand-related costs using an average 12 ERCOT coincident peak ("CP") demand allocation methodology. In order to track cost causation, AE's production demand-related costs should be allocated using an average and excess with four CP demand ("A&E w/4CP") allocation methodology.

(2) AE has incorrectly allocated its primary distribution demand-related costs using an average 12 non-coincident peak ("NCP") demand allocation methodology. Instead, AE's primary distribution demand-related costs should be allocated using the highest monthly NCP ("1NCP") demand allocation methodology.

(3) AE has incorrectly allocated primary distribution costs for poles, conductors, and underground ("UG") conduit to the Primary Voltage Above 20 MW at 85% Load Factor customer class.

(4) The cost of street lighting service to the City of Austin ("City") is not charged to the City as it should be, but is rather charged to the other customer classes through the Community Benefit Rider. This results in an unjustified charge being imposed on customer classes who do not contribute to the cost. As in other Texas cities, this rate class charge should already be accounted for in the City's budget and paid for with tax dollars rather than transferred to Austin residents. Otherwise, it amounts to an additional hidden general fund transfer.

(5) AE has failed to adjust test year revenues, energy sales, demand levels and billing determinants in February 2021 for the Winter Storm Uri outages for some customer classes. This omission will result in AE over-recovering its revenue requirement.

(6) In its class cost of service studies ("COSS"), AE improperly adjusts customer class demands for losses by applying the energy loss factors from the 2018 System Loss Study.

(7) AE's proposed COSS results in AE earning a rate of return ("ROR") from certain customer classes that is significantly higher than from other customer classes. This contravenes an established ratemaking principle that rate of return should be equally recovered across all customer classes. After correcting for the allocation issues discussed in (1) through (4) above, the differences in some customer class RORs are even greater.

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[1] NXP USA, Inc. is participating in this proceeding as NXP Semiconductors, Inc.

(8) AE's proposed distribution of its proposed $48.2 million base rate increase to the customer classes results in some customer classes paying substantial subsidies to other customer classes, and also results in some customer classes moving further from their cost of service. NXP's recommended revenue distribution addresses these problems and should be approved.

(9) The AE Cash Flow Methodology is flawed, necessitating several adjustments. These include:

a. A corrected methodology that results in a higher imputed rate of return of 13.8% (without a corresponding revenue requirements change;
b. An adjustment to the Internally Generated Funds for Construction ("IGFFC") level to make it closer to the City's actual average utilization of IGFFC; and
c. Adjustments to the level of General Funds Transfer.

(10) In consideration of these recommendations, we recommend a total, systemwide revenue requirement reduction of approximately $21.79_million, and a reduction in allocated costs to the Primary Voltage Above 20 MW service customer class of $4,551,614.

TESTIMONY OF JAMES W. DANIEL

PART I

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James W. Daniel. My business address is 919 Congress Avenue, Suite 1110, Austin, Texas 78701.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I received a Bachelor of Science degree from the Georgia Institute of Technology in 1973, majoring in economics.

Q. WHAT IS YOUR PRESENT POSITION?

A. I am an Executive Director for GDS Associates, Inc. ("GDS") of GDS's office in Austin, Texas.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. From July 1974 through September 1979 and from August 1983 through February 1986, I was employed by Southern Engineering Company. While employed by the Southern Engineering Company, I participated in the preparation of economic analyses regarding alternative power supply sources and generation and transmission feasibility studies for rural electric cooperatives. I also participated in wholesale and retail rate and contract negotiations with investor-owned and publicly-owned utilities, prepared cost of service studies on investor-owned and publicly-owned utilities and prepared and submitted testimony and exhibits in utility rate and other regulatory proceedings on behalf of publicly-owned utilities, industrial customers, associations, and government agencies.

From October 1979 through July 1983, I was employed as a public utility consultant by R. W. Beck and Associates. During that time, I participated in rate studies for publicly-owned electric, gas, water and wastewater utilities. My primary responsibility was the development of revenue requirements, cost of service, and rate design studies as well as the preparation and submittal of testimony and exhibits in utility rate proceedings on behalf of publicly-owned utilities, industrial customers, and other customer groups.

In 1986, I became a Principal of GDS and Manager of GDS's office in Austin, Texas. In April 2000, I was elected as a member of the Board of Directors and as a Vice President of GDS. In 2019, I became an Executive Director. While at GDS, I have provided testimony in numerous regulatory proceedings involving electric, natural gas, and water utilities, I have participated in generic rulemaking proceedings, I have prepared retail rate studies on behalf of publicly-owned utilities, I have prepared utility valuation analyses, I have prepared economic feasibility studies, and I have procured and contracted for wholesale and retail energy supplies.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. I have testified many times before regulatory commissions. I have submitted testimony before the following state regulatory authorities: the Public Utility Commission of Texas ("PUC" or the "Commission"), the Texas Commission on Environmental Quality, the Texas Railroad Commission, the Regulatory Commission of Alaska, the

Arkansas Public Service Commission, the Arizona Corporation Commission, the Delaware Public Service Commission, the Florida Public Service Commission, the Georgia Public Service Commission, the Illinois Commerce Commission, the State Corporation Commission of Kansas, the Louisiana Public Service Commission, the New Mexico Public Service Commission, the Oklahoma Corporation Commission, the Oregon Public Utility Commission, the Pennsylvania Public Utility Commission, the South Dakota Public Utilities Commission, the Utah Public Service Commission, the Virginia State Corporation Commission, and the West Virginia Public Service Commission. I have also testified before the Federal Energy Regulatory Commission ("FERC"), and two Condemnation Courts appointed by the Supreme Court of Nebraska. Additionally, I have submitted an expert opinion report before the United States Tax Court on utility issues. A list of regulatory proceedings in which I have presented expert testimony is provided as Exhibit NXP-JWD-1.

Q. WOULD YOU PLEASE DESCRIBE GDS?

A. GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Manchester, New Hampshire; Madison, Wisconsin; Orlando Florida; Augusta, Maine; Kirkland, Washington; and Camarillo, California. GDS has over 175 employees with diverse backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, storm, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, energy procurement and contracting, energy efficiency program development, financial analysis, load forecasting, and statistical services. Our clients are primarily privately-owned utilities, publicly-owned utilities, municipalities, customers of investor-owned utilities, groups or associations of customers, and government agencies.

Q. ON WHOSE BEHALF ARE YOU PREPARING A POSITION STATEMENT?

A. I am appearing and preparing a Position Statement on behalf of NXP USA, Inc. ("NXP"),[2] a large customer of Austin Energy ("AE") with a high load factor. NXP is one of AE's largest customers in terms of energy usage and demand and is a major employer and business in Austin; therefore, NXP has a vital interest in the Austin community and economy.

II. PURPOSE OF POSITION STATEMENT

Q. WHAT WAS YOUR ASSIGNMENT IN THIS PROCEEDING?

A. My assignment in this proceeding was to review and analyze the portions of AE's Base Rate Filing Package ("BRFP") related to customer class cost allocation and rate design.

Q. WOULD YOU PLEASE SUMMARIZE THE RESULTS OF YOUR REVIEWAND ANALYSIS?

A. Yes. Based upon my review and analysis, I have reached the following conclusions and recommendations:

(1) AE has incorrectly allocated its production demand-related costs using an average 12 ERCOT coincident peak ("CP") demand allocation methodology. In order to track cost causation, AE's production

[2] NXP is currently participating in this proceeding under the name NXP Semiconductors. However, it is contracted with Austin Energy as a customer under the name NXP USA, Inc.

demand-related costs should be allocated using an average and excess with four CP demand ("A&E w/4CP") allocation methodology.

(2) AE has incorrectly allocated its primary distribution demand-related costs using an average 12 non-coincident peak ("NCP") demand allocation methodology. Instead, AE's primary distribution demand-related costs should be allocated using the highest monthly NCP ("1NCP") demand allocation methodology.

(3) AE has incorrectly allocated primary distribution costs for poles, conductors, and underground ("UG") conduit to the Primary Voltage Above 20 MW at 85% Load Factor customer class.

(4) The cost of street lighting service to the City of Austin ("City") is not charged to the City but rather charged to the other customer classes through the Community Benefit Rider. This results in an unjustified charge being imposed on customer classes who do not contribute to the cost. As in other Texas cities, this rate class charge should already be accounted for in the City's budget and paid for with tax dollars rather than transferred to Austin residents. Otherwise, it amounts to an additional hidden general fund transfer.

(5) AE has failed to adjust test year revenues, energy sales, demand levels and billing determinants in February 2021 for the Winter Storm Uri outages for some customer classes. This omission will result in AE over-recovering its revenue requirement.

(6) In its class cost of service studies ("COSS"), AE improperly adjusts customer class demands for losses by applying the energy loss factors from the 2018 System Loss Study.

(7) AE's proposed COSS results in AE earning a rate of return ("ROR") from certain customer classes that is significantly higher than from other customer classes. This contravenes an established ratemaking principle that rate of return should be equally recovered across all customer classes. After correcting for the allocation issues discussed in (1) through (4) above, the differences in some customer class RORs are even greater.

(8) AE's proposed distribution of its proposed $48.2 million base rate increase to the customer classes results in some customer classes paying substantial subsidies to other customer classes, and also results in some customer classes moving further from their cost of service. My recommended revenue distribution addresses these problems and should be approved.

(9) In consideration of Chuck Loy's and my recommendations, we recommend a total, systemwide revenue requirement reduction of approximately $21.79__million, and a reduction in allocated costs to the Primary Voltage Above 20 MW service customer class of $4,551,614________.

III. ISSUES WITH PROCEDURAL GUIDELINES AND SCHEDULE

Q. DO YOU HAVE ANY CONCERNS REGARDING THE PROCEDURES THAT AE ESTABLISHED FOR THIS PROCEEDING TO EVALUATE ITS 2022 BASE RATE FILING PACKAGE?

A. Yes. AE, rather than the Impartial Hearing Examiner ("IHE"), established the procedures for parties to follow in reviewing AE's 2022 base rate filing package.[3] AE's procedures make it very difficult for parties to thoroughly and sufficiently analyze AE's 2022 rate study, even with the brief agreed extension of the discovery period and deadline to submit Position Statements.[4] I would also note that AE's procedures are

[3] While the IHE issued a procedural schedule for the case, the order adopts AE's proposed procedural schedule. *See* IHE Order No. 1 at 2-3 (Apr. 28, 2022) which states "Austin Energy has issued Procedural Guidelines for this Base Rate Review. The Procedural Guidelines are the rules by which the Base Rate Review will be governed…Austin Energy has set a Procedural Schedule for the Base Rate Review process. All participants should review and abide by the schedule…".

[4] On June 3, 2022, AE filed an updated Procedural Schedule which extended the initial discovery period and deadline to file Position Statements for by one week from the initial schedule. This updated schedule was adopted by IHE Order No. 4, issued June 6, 2022.

very different than my experience with how most other rate cases are processed. The primary problems with AE's procedures that restrict and impair parties' ability to analyze AE's 2022 BRFP include:

(1) The 2022 BRFP does not contain prefiled direct testimony that supports the rate study. Instead, intervenors are required to file testimony before AE files its testimony. This means that discovery on AE's Base Rate Filing Package is more of a fishing expedition to learn what AE's rationale is for the proposals in its filing rather than a meaningful opportunity for the parties to ask educated questions on AE's analyses.

(2) Parties are limited to submitting only 50 requests for information ("RFIs") to AE.

(3) The deadline for parties to file direct testimony is too short in comparison to AE's prior rate case and in comparison to the PUCT's procedures.

(4) AE is refusing to provide confidential information to parties, and has not offered the use of a Protective Order or Confidentiality Agreement to provide and protect confidential information, as is customary in other agency rate reviews.

Q. HOW MUCH TIME DID IT TAKE AE TO PREPARE ITS BASE RATE FILING PACKAGE COMPARED TO THE AMOUNT OF TIME PARTIES HAVE TO ANALYZE THE PACKAGE?

A. In response to SUN RFI No. 1-8, AE provided a copy of the request for proposals ("RFP") to retain a consultant to assist with the rate study that supports AE's proposed rate increase. As stated on bates page number 1053 of AE's responses, the consultant was scheduled to be engaged on May 1, 2020. AE's Base Rate Filing Package is dated

April 18, 2022. Therefore, it took AE approximately two years to prepare its rate study.[5] From the April 18, 2022, filing date of AE's rate study until the amended date for parties to file a Position Statement of June 22, 2022, parties (meaning customers of AE who are directly impacted by this case) only had a maximum of two months to analyze AE's rate study and prepare Position Statements. However, for most parties, the time it takes to retain attorneys and consultants shortened that two-month period. This considerable disparity in time for customer review, as opposed to the time it took AE to prepare this application, underscores the flaws within AE's required procedures.

IV. CUSTOMER CLASS COST OF SERVICE STUDIES

Q. WOULD YOU BRIEFLY DESCRIBE THE PURPOSE OF A CLASS COSS?

A. The primary purpose of a class COSS is to determine the portion of the utility's total retail cost of service or revenue requirement that should be borne by each customer class, in addition to other factors that may be appropriate to consider. Each cost component of the utility's total cost of service is either directly assigned or allocated to the various customer classes. The results are then considered to determine the level of revenues needed to be recovered through rates from each customer class so that the utility can have the opportunity to earn its overall revenue requirement. The results of the COSS will also provide important information for designing rates.

Q. WHAT ARE THE BASIC STEPS FOR PREPARING A CLASS COSS?

[5] Per page 1053 of the RFI responses, AE had already prepared some cost of service information prior to retaining a consultant.

A. A COSS is typically developed in three distinct steps. First, the various components of the utility's overall revenue requirements are assigned to their functional use, *e.g.*, production, transmission, distribution, metering, and billing and customer service. Next, the functionalized costs are classified based on cost causation factors to the cost categories of fixed or demand-related, variable or energy-related, and customer-related. Finally, the classified costs are directly assigned to their respective classes, or allocated to customer classes using allocation factors developed for each classified cost category. Various methodologies or approaches exist for conducting each step in the COSS process.

V. ALLOCATION OF PRODUCTION DEMAND-RELATED COSTS

Q. BRIEFLY DESCRIBE PRODUCTION DEMAND-RELATED COSTS.

A. Production costs are classified as either demand-related or energy-related costs. Typically, energy-related costs include those costs that vary with the generation of energy, such as fuel costs, and the energy charges and fuel charges for purchased power. Demand-related costs are mostly fixed costs that do not vary with the amount of energy generated. Examples of demand-related costs are investment costs for power plants and labor costs for operating power plants.

Q. HOW DOES AE PROPOSE TO ALLOCATE PRODUCTION DEMAND-RELATED COSTS?

A. As discussed on pages 60 and 61 of AE's Base Rate Filing Package, AE is proposing to use an "ERCOT 12 Coincident Peak ("ERCOT 12CP")" methodology to allocate production demand-related costs.

Q. WHAT SUPPORT DOES AE PROVIDE FOR THE ERCOT 12CP METHODOLOGY?

A. AE discusses its support for the proposed ERCOT 12CP methodology on pages 60 and 61 of its 2022 BRFP. In that discussion, AE provides two arguments as support for the ERCOT 12CP methodology. These are:

(1) The "allocation methodology better aligns the relationship between the costs and the benefits that accrue from owning and operating its fleet of generation in the ERCOT market," and

(2) The "methodology recognizes that all of Austin Energy's customers benefit from Austin Energy's generation fleet year-round."

Q. DO YOU AGREE WITH AE'S PROPOSED USE OF THE ERCOT 12CP ALLOCATION METHODOLOGY?

A. No, for several reasons. Generally, I do not agree because AE's support is misguided and is not based on cost causation. Cost causation is the primary basis for selecting an allocation methodology. Instead of selecting a method that allocates costs to customer classes based on cost causation, AE's support for the ERCOT 12CP allocation methodology is mostly related to its assessment of the customer benefits arising from the sale of energy produced by the AE generation fleet in the ERCOT wholesale market. As discussed further below, AE's system experiences its peak demands during the summer months. Therefore, AE's generating capacity has been developed and operated with the primary goal of meeting the summer peak system demands. AE's monthly peak demands (including those that occur coincident with the ERCOT peak demands) during non-summer months do not cause the production demand-related costs and should not be used for allocating costs.

More specifically, I disagree with using the ERCOT 12CP allocation methodology for the following reasons:

(1) ERCOT's and AE's planning and operations recognize the importance of the summer months (June-September) peak demands as compared to others.

(2) AE's demand side management programs recognize and prioritize the importance of AE's summer peak demands.

(3) For integrated electric utilities, the PUC consistently approves the average and excess ("A&E") w/4CP demand allocation methodology for allocating production demand-related costs.

(4) The A&E w/4CP demand allocation methodology was previously approved by the Austin City Council in Ordinance No. 20120607-055.

(5) Other municipally-owned utilities ("MOUs") use the A&E w/4CP demand allocation methodology.

(6) AE's use of the ERCOT 12CP methodology is not supported by the NARUC Electric Utility Cost Allocation Manual.

Based on the above, I recommend that AE's production demand-related costs be allocated using the average and excess with the average four summer month CP demands (A&E w/4CP).

Q. PLEASE EXPLAIN THE A&E W/4CP DEMAND ALLOCATION METHODOLOGY.

A. The average and excess methodology considers both average demands and peak demands of the customer classes. The average demand is usually determined using customer class energy usage and the excess demand is typically determined using the customer class critical monthly CP demands. For AE, the use of the four summer month CP demands reflects the importance AE's summer peaking system.

The average demand is determined by dividing the class's annual energy usage by 8760 hours. The excess demand is determined by subtracting the average demand from the class's 4CP demand. The average demand component is weighted by the system load factor with the excess demand weighted by one minus the system load factor.

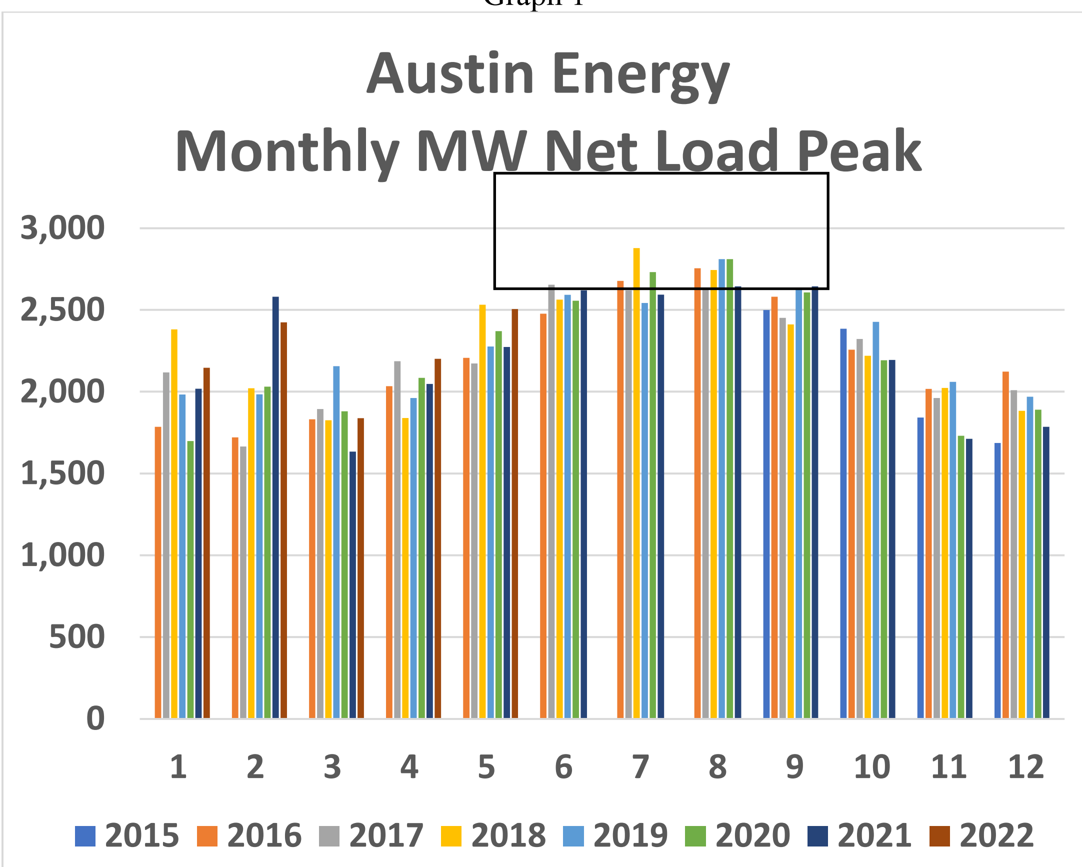
Q. WHY DO UTILITIES AND REGULATORY AGENCIES UTILIZE THE A&E W/4CP METHODOLOGY?

A. It is used for allocating costs to retail customer classes. The methodology uses the critical monthly system peak demands during the summer months. The average demand component also ensures that costs are allocated to classes, such as outdoor lighting, that may not be on during the times of system CP demands.

Q. WHAT IS THE BASIS FOR YOUR CLAIM THAT AE AND ERCOT BOTH ARE PREDOMINANTLY SUMMER PEAKING?

A. Below is a bar graph depicting AE's monthly MW net peak load data from September 2015 through May 2022 as provided in RFI NXP - 1-2. The graph clearly illustrates the summer peaking nature of the AE system. The peak loads during the summer season months of June, July, August, and September are consistently higher than the other months of the year and drive the amount of production capacity needed to hedge their load requirements. There are some winter anomalies such as February 2021, however the consistent pattern is of a summer peaking utility system.

Graph 1



Q. IS THE ERCOT SYSTEM ALSO SUMMER PEAKING?

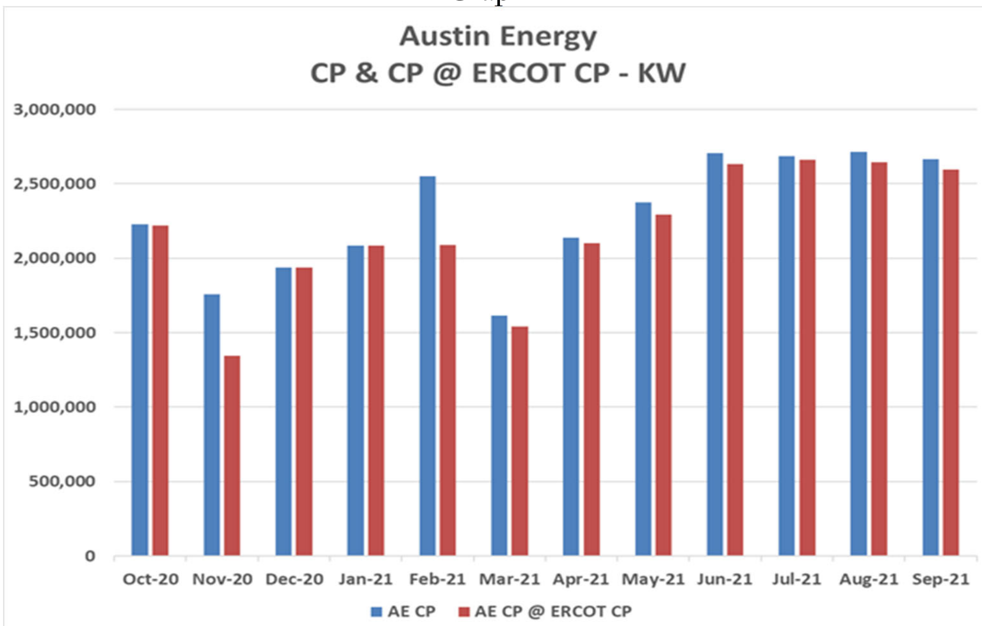
A. Yes. ERCOT experiences its largest system peak demand in the summer months and must plan to have adequate total demand-related generation capacity to meet the maximum peak demand plus reserves. ERCOT produces a Seasonal Assessment of Resource Adequacy for the ERCOT Region ("SARA") for all four seasons of the year. However, the Summer SARA clearly assesses whether there is adequate generation production capacity to meet the ultimate ERCOT peak hour of demand for the year. Insofar as AE's system relates to ERCOT system peak demands, AE's concern for total system capacity should lie within the summer months as that is when ERCOT peak demands occur. That is precisely what ERCOT uses for its own system peak planning. It follows that peak demands occurring during the summer months are the drivers of demand-related production costs, and not those demands occurring during non-summer months.

Q. DO AE'S MONTHLY COINCIDENT PEAK DEMANDS CLOSELY FOLLOW AE'S MONTHLY PEAK DEMANDS COINCIDENT WITH THE ERCOT PEAK DEMANDS?

A. Yes. Below is a graph illustrating the close relationship between the AE's monthly coincident peak demands and AE's monthly peak demands coincident with the ERCOT peak demands during the test year October 2020 through September 2021 (AE WP F 6.1). The February 2021 data is an anomaly, driven by an isolated extreme cold weather event. The graph clearly depicts the summer peaking nature of ERCOT, and the AE

CP loads, further supporting use of a A&E w/4CP allocation factor for AE's demand related production costs.

Graph 2



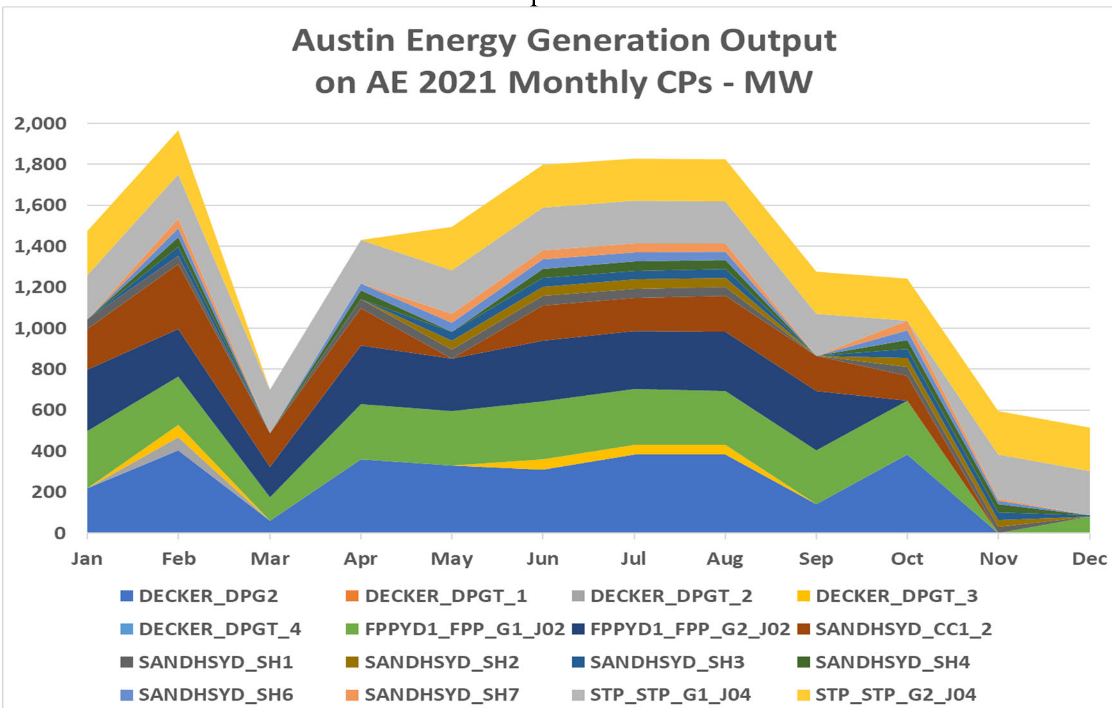
Q. DO AE'S GENERATION RESOURCES ALSO OPERATE AT GREATER CAPACITY LEVELS DURING PEAK DEMAND PERIODS IN THE SUMMER MONTHS AS DIRECTED BY ERCOT'S SECURITY CONSTRAINED ECONOMIC DISPATCH?

A. Yes, they do. Below is a stacked line graph depicting AE's individual generation resource capacity output[6] during AE's peak demand hour for each of the twelve months of 2021[7]. Again, the sum of AE's individual generation resource MW output is higher during the summer months than the other months except for February 2021 whose extreme weather conditions were a clear anomaly. The graph demonstrates that AE's production demand capacity was planned and continues to be economically dispatched

6 *See* Austin Energy's Response to NXP 3-5
7 *See* Austin Energy's Response to NXP 1-2

by ERCOT consistent with AE's customer peak load requirements occurring in the summer months.

Graph 3



Q. HAS THE FACT THAT AE IS NOW OPERATING ITS GENERATION IN THE ERCOT NODAL MARKET CHANGED AE'S NEED TO SIZE ITS DEMAND-RELATED PRODUCTION CAPACITY FOR AE'S SUMMER PEAK REQUIREMENTS?

A. No. The above graph illustrates that AE's generation capacity operating based on ERCOT's security constrained economic dispatch is aligned with meeting and hedging AE's customer peak load requirements occurring in the summer months.

Q. IN GENERAL TERMS PLEASE DESCRIBE HOW AE'S GENERATION RESOURCES OPERATE IN THE ERCOT NODAL MARKET AND HOW THE COST AND REVENUES FLOW THROUGH TO AE'S CUSTOMERS.

A. AE, operating as an integrated municipal electric utility and a non-opt-in entity ("NOIE") in ERCOT, schedules all its load for purchase from the ERCOT nodal market. AE also offers all its generation into the market through a combination of energy and ancillary service schedules. ERCOT dispatches all the generators based on a "security constrained economic dispatch" at their marginal cost, adjusted for congestion constraints for the applicable time period. AE and other ERCOT generators in ERCOT are paid the locational-marginal-price ("LMP") as adjusted for congestion during the time periods when they are dispatched as a part of the economic generation stack for the whole system. Basically, AE buys at the market price when the LMP is below its generation cost (i.e. AE will not run its generation to serve its loads), and net pay at its generation cost when the LMP is above that cost (i.e. AE offers its generation resource to ERCOT for dispatch). When AE's generation units are dispatched, AE pays the higher LMP for its load, expends its variable cost to run the units, and is paid the higher LMP for its generation output. When AE's generation units are dispatched by ERCOT, all three parts flow through and are matched together in the power cost adjustment factor basically hedging AE's cost for that time period approximately at its variable generation cost.

Q. DO AE'S OPERATIONS IN THE ERCOT NODAL MARKET PRODUCE A PROPER ALIGNMENT OF AE'S ENERGY-RELATED PRODUCTION COSTS, INCLUDING ITS BENEFITS AND COSTS FROM THE ERCOT NODAL MARKET?

A. Yes, they do. The physical and financial hedge benefit from AE's energy-related production costs net generation revenue from ERCOT are separately paired with AE's associated purchase of all the power necessary from ERCOT to serve its own customers flowing through the Power Supply Adjustment "(PSA").[8] AE has appropriately aligned the hedge benefits. Of AE's generation with AE's associated purchases for its customers from the ERCOT nodal market in the AE PSA.

Q. IS AE'S PSA A CONSIDERATION IN OR A PART OF THIS AUSTIN ENERGY 2022 RATE REVIEW?

A. No. AE states that the AE PSA is "not a part of this base rate review."[9]

Q. SHOULD AE'S DEMAND-RELATED PRODUCTION COSTS BE ALLOCATED TO CUSTOMER CLASSES BASED ON AN ALIGNMENT WITH AE'S ENERGY-RELATED PRODUCTION BENEFITS AND COSTS?

A. No. Based on AE's own statements, alignment of AE's generation production hedge benefits and costs appropriately flow through the PSA which is neither a part nor a driver of this base rate review. Allocation of demand-related production costs to customer classes in this base rate review should be based on cost causation principles which are driven by AE's peak demands occurring in the summer months.

Q. HOW DO AE'S DEMAND SIDE MANAGEMENT PROGRAMS RECOGNIZE THE IMPORTANCE OF AE'S SUMMER PEAK DEMANDS?

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[8] Austin Energy Rate Review Filing Package at page 51 of 154.
[9] Austin Energy Rate Review Filing Package at page 51 of 154.

A. AE's own system planning, and demand side management programs continue to reflect the importance of AE's demands during the summer. On August 12, 2019, Austin's Electric Commission ("EUC") created the Resource Plan Working Group ("Working Group") to provide recommendations and strategic goals to Austin Energy and the Austin City Council on technical and market issues to meet environmental efficiency and affordability goals established by the Austin City Council. On March 5, 2020, the Working Group finalized the "Austin Energy Resource, Generation and Climate Protection Plan to 2030" Vision Plan based on analysis of the risks, costs and opportunities to meet the future demand for electricity. The AE Vision Plan states "Austin Energy will maintain an energy supply portfolio sufficient to offset customer demand while eliminating carbon and other pollutant emissions from its electric generation facilities as rapidly as feasible within the limitations set by the Austin City Council"he Vision Plan further highlights that the retirement of the Decker Prairie Steam gas-fired units was delayed until after the summer peaks of 2020 and 2021 .[10] The Vision Plan also states that "Austin Energy will sponsor energy efficiency and demand response initiatives aimed to reduce overall system load and reduce peak demand." [11].

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING AE'S PROPOSED USE OF A 12CP ALLOCATION FACTOR FOR DEMAND-RELATED PRODUCTION COSTS?

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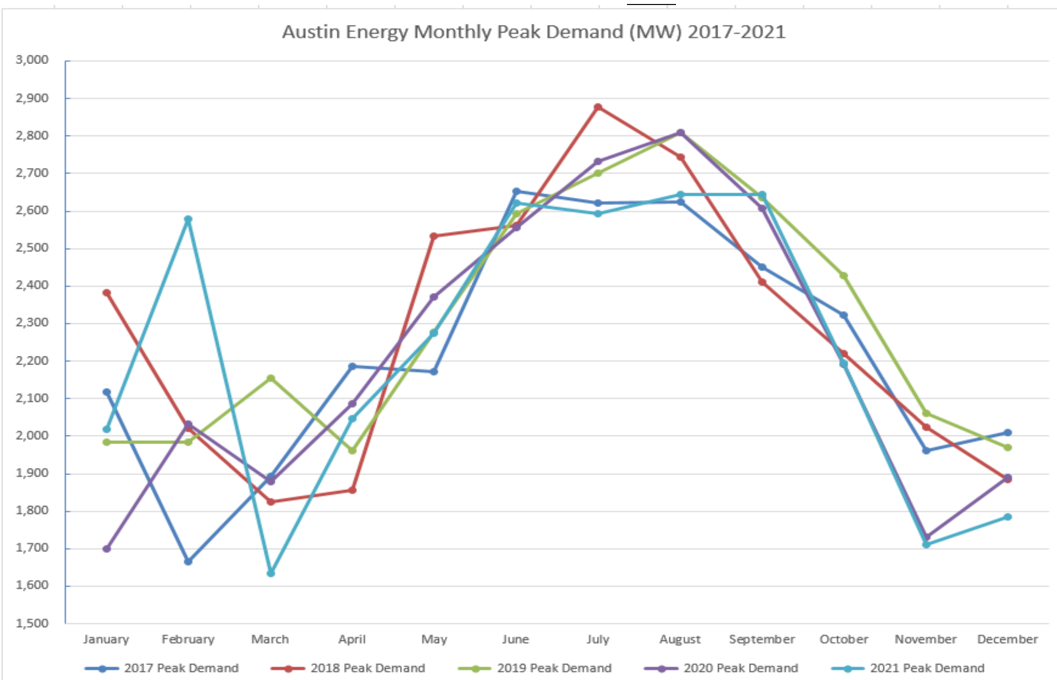
[10] *See* Austin Energy's Response to NXP 1-6
[11] *See* Austin Energy's Response to NXP 1-6

A. Yes. AE's response to request for information ("RFI") TIEC 1-3 further confirms the summer peaking nature of AE's peak demands for 2017-2021. Using the peak demand data provided in that RFI response the graph below illustrates the significance of AE's summer peak demands. A copy of that RFI response is provided as my Exhibit NXP-JWD-3.

Table-1___



In summary, the allocation of AE's demand-related production costs based on 12CP demands with the ERCOT peaks has no basis in cost causation for AE's demand-related production costs and should not be used.

Q. DO INVESTOR-OWNED UTILITIES ("IOUs") IN TEXAS USE THE A&E W/4CP DEMAND ALLOCATION METHODOLOGY?

A. Yes, all of the IOUs in Texas that are integrated use the A&E w/4CP methodology to allocate production demand-related costs. The PUC has approved the A&E w/4CP for those utilities and for the unbundled IOUs before they were unbundled.

Q. DO ANY MUNICIPALLY-OWNED UTILITIES ("MOUs") WITH GENERATION USE THE A&E W/4CP DEMAND ALLOCATION METHODOLOGY?

A. Yes. I am aware of MOUs that use the A&E w/4CP methodology for allocating production demand-related costs.

Q. HAS THE AUSTIN CITY COUNCIL PREVIOUSLY ACCEPTED THE USE OF THE A&E W/4CP DEMAND-ALLOCATION METHODOLOGY FOR AE?

A. Yes, Austin City Council Ordinance No. 20120607-055 addresses AE's 2012 base rate review. Part 6 of the Ordinance states:

Part 6. The Council adopts as policy the use of the A&E 4CP methodology to allocate production demand costs among customer rate classes.

I am not aware of any subsequent City Council Ordinances that have changed or rescinded this policy. A copy of this Ordinance is provided as my Exhibit NXP-JWD - 4__.

VI. ALLOCATION OF PRIMARY DISTRIBUTION DEMAND-RELATED COSTS

Q. PLEASE DESCRIBE HOW AE PROPOSES TO ALLOCATE PRIMARY DISTRIBUTION SYSTEM COSTS TO THE CUSTOMER CLASSES.

A. Primary distribution facilities include substations, poles, overhead ("OH") and underground ("UG") conductors or lines, and UG conduit. As discussed on page 62 of AE's Base Rate Filing Package, AE is proposing to allocate the costs of these facilities using a 12-month average of the customer classes' monthly NCP demands for the test year. AE refers to this cost allocation methodology as the 12NCP method.

Q. HOW DOES AE SUPPORT ITS USE OF A 12NCP ALLOCATION METHOD?

A. The "support" that AE provided in the Base Rate Filing Package does not support a 12NCP allocation methodology, in my opinion. On page 62 of AE's Base Rate Filing Package, AE states:

> Distribution facilities such as substations that directly interconnect with the transmission system are designed to meet the aggregated customer loads in specific geographic areas. As the systems are designed to meet localized demands, the costs are most appropriately allocated by the magnitude and timing of the class peak demand, which often occurs at times different from the system peak demand.

These class peak demands are referred to as class NCP demands. As recognized in the AE quote above, distribution facilities are sized and built to meet the localized peak demands. Therefore, it does not make any sense to use a 12-month average NCP demand to allocate primary distribution plant costs. To appropriately reflect cost causation, a 1NCP or annual NCP demand should be used for allocating primary distribution plant costs.

Q. DO OTHER STATEMENTS IN THE BASE RATE FILING PACKAGE SUPPORT THE USE OF A 1NCP DEMAND ALLOCATION METHODOLOGY?

A. Yes. On page 57 of AE's Base Rate Filing Package, AE states:

> The distribution function is concerned with meeting localized demands; therefore, class maximum demands are used to allocate distribution costs. Finally, for individual customers, Austin Energy is concerned with the maximum demand that the customer places on the system. These demands are significant cost drivers for Austin Energy's capital expenses, including debt.

As recognized by AE, class and customer peak demands are the "cost drivers" for its distribution costs. The peak demands occur during the summer months. The off-peak demands in the non-summer months do not cause distribution system costs. AE's use of the 12NCP demand allocation methodology is contrary to what causes AE to incur the majority of its distribution system costs. Including non-summer months in the allocation factor shifts costs away from the customers that create the costs and imposes them on customers who do not create those costs.

Q. DOES AE ACKNOWLEDGE THAT PEAK DEMANDS ARE USED FOR PLANNING FOR THE NEED OF NEW DISTRIBUTION FACILITIES?

A. Yes. In supplemental response to NXP 3-11, AE provided a document titled "Distribution Planning Criteria." That report states that "distribution capacity studies assume summer peak conditions to determine substation peak loading." A copy of that RFI response is provided as my Exhibit NXP-JWD-5.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING AE'S PROPOSED USE OF A 12NCP ALLOCATION METHODOLOGY FOR ALLOCATING PRIMARY DISTRIBUTION COSTS?

A. Yes. AE's substations are functionalized to both the transmission and distribution functions. The transmission-related portion of the substation is recovered in AE's wholesale transmission cost of service ("TCOS"). AE's TCOS rates are based on the CP demands in the four summer months. This recognizes the importance of peaks during the summer. For the distribution-related portion of each substation, AE's proposed 12NCP allocation methodology de-emphasizes the importance and cost causation of the peak demands on the substations.

Q. FOR COMPARISON PURPOSES, HOW DOES THE PUC USUALLY ALLOCATE PRIMARY DISTRIBUTION DEMAND-RELATED COSTS?

A. Based on my experience, the PUC usually supports a 1NCP demand allocation methodology for both integrated and unbundled IOUs. I have never seen the PUC accept a 12NCP demand allocation methodology for allocating distribution costs. Examples of utilities in Texas that allocate distribution costs using a version of a 1NCP demand allocation methodology are (1) Oncor and(2) Southwestern Public Service Company.

Q. DO ANY MOUs USE THE 1NCP DEMAND ALLOCATION METHODOLOGY?

A. Yes, I am aware of MOUs that use 1NCP methodology for allocating distribution demands-related costs.

VII. SUBSTATION SERVICE

Q. DOES AE ALLOCATE PRIMARY DISTRIBUTION SYSTEM COSTS TO ALL CUSTOMER CLASSES?

A. AE allocates primary distribution system costs to all customer classes except to the two transmission voltage customer classes, which do not use the primary distribution system.

Q. WHAT TYPES OF FACILITIES ARE INCLUDED IN AE'S PRIMARY DISTRIBUTION SYSTEM?

A. All distribution facilities that operate at a primary voltage are included as part of AE's primary distribution system. These facilities include the distribution-related portion of substations, primary poles and towers, primary OH lines and UG lines, and primary UG conduit.

Q. DO ALL NON-TRANSMISSION VOLTAGE CUSTOMERS USE ALL OF THE PRIMARY DISTRIBUTION SYSTEM FACILITIES?

A. NO. AT THE SECOND TECHNICAL CONFERENCE AND IN WRITTEN RESPONSE TO TIEC QUESTION TIEC TC 2-1A, AE STATED THAT ALL CUSTOMERS IN THE PRIMARY VOLTAGE ABOVE 20 MW AT 85% LOAD FACTOR CUSTOMER CLASS ARE "SERVED DIRECTLY FROM AUSTIN

ENERGY OWNED DISTRIBUTION SUBSTATIONS." IN OTHER WORDS, THE POINT OF DELIVERY ("POD") TO THESE CUSTOMERS, AND WHERE THESE CUSTOMERS TAKE OWNERSHIP OF THE ENERGY FROM AE, IS AT A SUBSTATION. THEREFORE, THESE CUSTOMERS DO NOT UTILIZE THE POLES, OH LINES, AND UG LINES AND CONDUIT PORTION OF THE PRIMARY DISTRIBUTION SYSTEM.Q.DO YOU AGREE WITH AE'S ALLIOCATION OF PRIMARY DISTRIBUTION POLES AND LINES TO THE PRIMARY VOLTAGE ABOVE 20 MW CUSTOMER CLASS?

A. No. Customer classes should not be required to pay for facilities they do not use.

Q. DID AE RECENTLY MODIFY ITS RESPONSE TO THE SECOND TECHNICAL CONFERENCE QUESTION TIEC TC 2-1A?

A. Yes. AE filed an amended response to TIEC Question TIEC TC 2-1A. In its amended response, AE changed its response from "confirmed" to "not confirmed" regarding the question whether all of the Primary Voltage Over 20 MW customers are served directly from AE-owned substations. I would also point out that in its amended response, AE neglected to respond to the second part of the question which states:

> If not confirmed, list the customers who are not served directly from Austin Energy owned distribution substations.

Apparently, AE has not confirmed one way or the other whether some, or all Primary Voltage Over 20 MW customers are served directly from an AE substation and has also not identified any of these customers that are not served directly from an AE substation.

Q. DOES THIS AMENDED AE TECHNICAL CONFERENCE RESPONSE CHANGE YOUR RECOMMENDATION ON NOT ALLOCATING PRIMARY DISTRIBUTION POLES AND LINES TO THE PRIMARY VOLTAGE ABOVE 20 MW CUSTOMER CLASS?

A. No. The cost of these AE primary distribution system facilities should not be recovered in base rates from this customer class. If the delivery point of any customer in the class is on a short feeder out of a substation, then the cost of the feeder is more appropriately recovered through a facilities charge rather than requiring that one customer to pay for a load ratio share of the entire AE system's primary distribution poles and lines costs. This rate option should be available to the Primary Voltage Above 20 MW customers.

Q. DOES THE PUC AGREE THAT CUSTOMERS RECEIVING SERVICE FROM SUBSTATIONS, OR A SHORT DISTANCE FROM A SUBSTATION, SHOULD NOT PAY FOR DISTRIBUTION LINES?

A. Yes. For some IOUs that serve customers directly from substations, the PUC has approved rate classes and rates for those customers that do not recover distribution lines costs. For example, Oncor has a substation service rate class.

VIII. SERVICE AREA STREET LIGHTING

Q. DOES AE PROVIDE SERVICE TO A STREET LIGHTING CUSTOMER CLASS?

A. AE does provide street lighting service to the City. However, there is not a street lighting rate class as AE provides this service to the City for free.

Q. WHAT IS THE COST OF THIS STREET LIGHTING SERVICE AND WHO PAYS FOR IT?

A. As shown on Schedule G-6 of AE's COSS, the cost of serving area street lighting for the City was $19,179,377 during the test year. This amount will be recovered from the other customer classes through the Community Benefit Rider that is applied to customers within the Austin City Limits.

Q. DO YOU AGREE WITH TREATMENT OF AE'S STREET LIGHTING SERVICE TO THE CITY?

A. No. This is essentially another AE transfer to the City's General Fund. As discussed in the testimony of NXP witness Chuck Loy, AE's proposed General Fund Transfer is already too high without the free street lighting service. AE should be required to develop a rate schedule for streetlighting service and charge the City for this service. This will reduce the charges for the other customer classes by $19,179,377.

IX. WINTER STORM URI

Q. HOW DID AE ADJUST ITS BASE RATE STUDY FOR IMPACTS CAUSED BY WINTER STORM URI?

A. For the weather sensitive customer classes, AE conducted a weather normalization analysis. This analysis should have adjusted these customer classes' energy and demand levels for Winter Storm Uri impacts. For the non-weather sensitive customer classes, AE has not made any adjustments to its 2021 Electric System Rate Study for impacts caused by Winter Storm Uri.

Q. DO YOU AGREE THAT NOT ADJUSTING THE RATE STUDY FOR WINTER STORM URI FOR SOME CUSTOMER CLASSES IS APPROPRIATE?

A. No. For the non-weather sensitive customer classes, Winter Storm Uri made a significant impact on their February 2021 revenues, energy usage and demands. Ignoring those impacts likely causes AE's rate study to be flawed. For these customer classes, test year revenue levels, energy usage demands and billing determinants for February 2021 likely need adjusting.

Q. WERE YOU ABLE TO DO MAKE ALL OF THESE ADJUSTMENTS?

A. No. The information to do that was not available for some of these customer classes. AE has the data and should be required to do that analysis.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE WINTER STORM URI IMPACTS?

A. Yes. Since my adjusted COSS uses allocation methodologies using summer peak demand data, Winter Storm Uri is not a significant concern with my COSS results. However, using billing determinants that have not been adjusted for Winter Storm Uri to design the approved rates is a concern and could result in rates that will over-recover AE's costs when those rates are applied to future billing determinants.

X. ADJUSTMENT FOR DEMAND LOSSES

Q. PLEASE EXPLAIN WHY THE TREATMENT OF LOSSES IN A CLASS COSS IS IMPORTANT.

A. Customers take service at different voltage levels on AE's system. AE incurs system energy and demand losses at each voltage level. Accordingly, customers receiving service at lower voltages cause more losses than customers receiving service at higher voltages. When allocating costs, it is important to adjust customer energy and demand at their sales or delivery level to the generation voltage level so that allocation factors are calculated on a comparable voltage level. This ensures that customers and customer classes pay for the losses they cause.

Q. PLEASE DESCRIBE APPENDIX D "AUSTIN ENERGY SYSTEM LOSS STUDY FOR FISCAL YEAR 2018" THAT IS INCLUDED IN AE'S BASE RATE FILING PACKAGE.

A. The AE System Loss Study was performed for use in preparing the class COSS. The loss study is based on load flow results at the 2018 system peak that occurred in July. Using this information and facility specifications, AE calculates the energy loss amounts and percentages at each voltage level of the system and for the substations and lines at each voltage level.

Q. HOW DID AE USE THE RESULTS OF THE SYSTEM LOSS STUDY IN THE CLASS COSS?

A. As shown on Workpaper F-6.1.2, AE adjusted normalized energy sales and demands at the meter for each customer class to the generation level to adjust for the percent energy losses at each applicable voltage level.

Q. DID AE ALSO ADJUST CP AND NCP DEMANDS USED FOR ALLOCATION FACTORS FOR LOSSES?

A. Yes, but AE's demand loss adjustment was done incorrectly.

Q. PLEASE EXPLAIN THE ERROR IN AE'S LOSS ADJUSTMENTS TO THE CUSTOMER CLASS CP AND NCP DEMANDS.

A. Instead of adjusting the customer class CP and NCP demands using demand loss factors, AE used energy loss factors. This error was confirmed by AE in response to TIEC RFI No. 5-4.

Q. WHAT IS THE EFFECT OF THIS ERROR?

A. Distribution demand loss factors are typically greater than distribution energy loss factors. In other words, customers incur greater demand losses than energy losses on a percentage basis. By incorrectly using the energy loss factors, AE has under-adjusted the CP and NCP demands of customer classes receiving service at secondary distribution voltages. This results in under-allocating distribution costs to the secondary voltage customer classes and over-allocating costs to the primary voltage customer classes.

Q. DID YOU CORRECT AE'S LOSS ADJUSTMENTS TO THE CUSTOMER CLASS CP AND NCP DEMANDS USED FOR CALCULATING ALLOCATION FACTORS?

A. No. The System Loss Study provided as Appendix D only develops energy loss factors. In response to TIEC RFI No. 5-5, AE stated that it did not conduct the analysis necessary to develop demand loss factors.

Q. WHAT IS YOUR RECOMMENDATON REGARDING THIS COST ALLOCATION PROBLEM?

A. AE should be ordered to develop and use demand loss factors in future base rate reviews.

XI. ADJUSTED CLASS COST OF SERVICE STUDY

Q. HAVE YOU DEVELOPED AN ADJUSTED COST OF SERVICE STUDY BASED ON THE RECOMMENDATION OF CHUCK LOY AND YOUR RECOMMENDED CHANGES DISCUSSED ABOVE?

A. Yes. The results of my adjusted COSS are provided as my Exhibit NXP-JWD-6_. Table - 2, below compares each customer class's current base rate revenues with its cost of service in my adjusted COSS.

Table – 2

	Current Base Rate Revenues	NXP Base Rate Cost of Service	Under/(Over) Recovery - $	Under/(Over) Recovery - %
Residential	$ 298,139,951	$ 381,153,142	$ 83,013,191	27.8%
Secondary Voltage < 10 kW	22,062,516	23,667,983	1,605,467	7.3%
Secondary Voltage ≥ 10 < 300 kW	146,379,682	112,137,947	(34,241,735)	-23.4%
Secondary Voltage ≥ 300 kW	97,431,981	78,383,098	(19,048,883)	-19.6%
Primary Voltage < 3 MW	8,571,888	9,529,850	957,962	11.2%
Primary Voltage ≥ 3 < 20 MW	24,590,380	22,471,254	(2,119,126)	-8.6%
Primary Voltage ≥ 20 MW @ 85% aLF	33,906,126	29,417,951	(4,488,175)	-13.2%
Transmission	801,058	1,184,535	383,478	47.9%
Transmission Voltage ≥ 20 MW @ 85% aLF	4,236,381	2,980,278	(1,256,103)	-29.7%
Service Area Street Lighting	-	-	-	n/a
City-Owned Private Outdoor Lighting	2,141,558	3,776,789	1,635,231	76.4%
Customer-Owned Non-Metered Lighting	45,878	73,005	27,127	59.1%
Customer-Owned Metered Lighting	316,344	439,417	123,072	38.9%
Total	**$ 638,623,744**	**$ 665,215,248**	**$ 26,591,505**	**4.2%**

XII. AE'S PROPOSED CUSTOMER CLASS REVENUE DISTRIBUTION

Q. PLEASE EXPLAIN WHAT IS MEANT BY A CUSTOMER CLASS REVENUE DISTRIBUTION.

A. A customer class revenue distribution is the determination of how a utility's total revenue increase is to be distributed among the customer classes. If customer class revenue levels are to be set equal to the cost of serving each customer class, then the revenue increase (or decrease) for each customer class is based on the approved COSS. In some instances, factors other than cost of service are considered, and the revenue distribution will vary from the COSS results.

Q. IS AE PROPOSING TO SET CUSTOMER CLASS REVENUE LEVELS EQUAL TO EACH CLASS'S ALLOCATED COST OF SERVICE?

A. No. AE's COSS results show that certain customer classes would receive significant percent base rate increases if their revenue levels were set equal to their cost of service. As a result, AE is proposing gradualism to moderate base rate revenue increases for certain rate classes.

Q. PLEASE EXPLAIN WHAT IS MEANT BY GRADUALISM?

A. Gradualism is a rate setting tool or methodology used by utilities, and regulatory agencies, to gradually move customer class revenue levels towards the class's cost of service in situations where the COSS shows a significant base rate increase would be required to set the class's revenue level equal to their cost of service. Using gradualism, the increase to a class is set below the cost of service to minimize the impact, or avoid "rate shock." The revenue shortfall resulting from gradualism is spread across multiple customer classes. This represents a subsidy as between rate classes. As stated on page 73 of AE's Base Rate Filing Package, "Austin Energy applies a moderate approach to address cost of service imbalances to mitigate rate shock."

Q. PLEASE EXPLAIN AE'S PROPOSED CUSTOMER CLASS REVENUE DISTRIBUTION AND GRADUALISM PROPOSAL.

A. Section 6, Class Revenue Distribution, of AE's Base Rate Filing Package, further describes AE's proposed class revenue distribution methodology. AE describes its methodology as a "standardized gradualist approach" with three steps. The first step, which is not standard, is to increase the current rate revenues of each customer class by the proposed system average percent base rate revenue increase which is 7.55%. For the second step, AE then compares this artificial class revenue amount, which AE refers to as the "Gross-Up Base Revenues," to each class's allocated cost of service. That comparison produces a shortfall or surplus of the grossed-up base revenues versus the allocated class cost of service. For AE's proposed revenue distribution, it then increases or decreases each class's current base rate revenues by one-half of the class's shortfall or surplus amount. Those amounts are shown in column (F) of Table G-A on page 77 of AE's Base Rate Filing Package. AE's third step assigns the revenue shortfall from the 20% rate discount provided to the State of Texas facilities school districts and military facilities to the customer classes pro-rata based on the classes' cost of service. The resulting AE proposed class revenue distribution is shown on column (I) of AE's Table 6-A.

Q. HAVE YOU EVER SEEN A UTILITY PROPOSE A SIMILAR CLASS REVENUE DISTRIBUTION METHODOLOGY?

A. No. While steps 2 and 3 are not unusual, I have never seen AE's step 1 used by any other utility.

Q. HOW DOES AE SUPPORT STEP 1 OF ITS REVENUE DISTRIBUTION METHODOLOGY?

A. AE claims step 1 is needed "to align all customer classes in comparison to cost of service." However, for some customer classes, this step moves them further from cost of service in opposition to AE's stated goal of moving class revenues towards cost of service. For example, the Secondary Voltage Greater Than 300 kw customer class's current revenues are already above the class's cost of service. By increasing the class's current revenues by the overall percent revenue increase needed of 7.6%, this class is moved further above its cost of service. However, as stated on page 75 of the Base Rate Filing Package, AE wants to disregard the system movement in step 1 so that their methodology can be described as moving halfway to cost."

Q. WHAT IS YOUR RECOMMENDED CLASS REVENUE DISTRIBUTION?

A. Based on my adjusted cost of service study, I recommend a different revenue distribution methodology to limit the base rate percentage increases for some customer classes. I recommend limiting the increase to any customer class to the residential increase should be capped to avoid rate shock by capping the residential increase by approximately 8%". This still leaves a significant revenue shortfall from these capped customers classes that needs to be recovered from the other customer classes. As a result, the revenue decreases for the customer classes that should receive significant decreases were limited to 0.2% decreases.

As shown on Table 2 above, the current rate revenues of some customer classes are substantially below their cost of service. Moving those customer classes' revenues to cost service would result in large percentage increases. I propose moving these customer classes 1/3 of the way to their cost of service in order to alleviate those impacts. This will still result in some of the customer classes receiving significant subsidies from the other customer classes which are currently over-recovering their cost of service. The remaining customer class subsidies after the 1/3 move to cost of service will need to be assigned to the other customer classes. I propose to do this by proportionately spreading to the other classes the "net" over-recovery (their cost of service over-recovery less the subsidies) based on their cost of service so that some of the subsidy they currently pay is reduced. These classes will also receive small rate decreases.

This revised revenue distribution is provided as my Exhibit NXP-JWD-7/ As shown on this exhibit, the residential customer class will still receive a substantial subsidy under my proposed revenue distribution.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING AE'S DISTRIBUTION OF ITS PROPOSED REVENUE INCREASE AMONG THE CUSTOMER CLASSES?

A. Yes. AE's Base Rate Filing Package states that a major cause for the need to increase base rates is the unprecedented customer growth since the last rate case. This is illustrated on Figure 7-21 on page 99 of AE's Base Rate Filing Package. The table below shows customer growth for the major customer classes from October 2016 to September 2021.

Table 5___

No. of Customers per Rate Study	September 2014 [1]	2021/2022 [2]	Increase / (Decrease)
Residential	385,518	478,047	92,529
Secondary Voltage < 10 kW	28,211	34,769	6,558
Secondary Voltage ≥ 10 < 300 kW	17,446	17,623	177
Secondary Voltage ≥ 300 kW	1,149	790	(359)
Primary Voltage < 3 MW	102	83	(19)
Primary Voltage ≥ 3 < 20 MW	19	27	8
Primary Voltage ≥ 20 MW @ 85% aLF	3	3	-
Transmission	3	3	-
Transmission Voltage ≥ 20 MW @ 85% aLF	1	1	-
Service Area Street Lighting	7	8	1
City-OwnedPrivate Outdoor Lighting	3,978	13,554	9,576
Customer-Owned Non-Metered Lighting	1	2	1
Customer-Owned Metered Lighting	61	74	13
Total	**436,499**	**544,984**	**108,485**

[1] Source: Austin Energy's Tariff Package: 2015 Cost of Service Study and Proposal to Change Base Electric Rates; Austin Energy's Response to NXP/Samsung's 1st RFI: NXP/Samsung 1-28, Bates No. 298

[2] Source: 2022 Austin Energy Base Rate Review, WP F-6.1 Normalized Load Research Data

As shown above, of the 108,485 increase in customers over this period, 92,529 are residential customers. I would also note that the number of customers in the Primary Voltage Above 20 MW customer class has not increased since AE's last rate case.

XIII. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Yes. Based upon my review and analysis, I have reached the following conclusions and recommendations:

(1) AE has incorrectly allocated its production demand-related costs using an average 12 ERCOT coincident peak ("CP") demand allocation methodology. In order to track cost causation, AE's production demand-related costs should be allocated using an average and excess with four CP demand ("A&E w/4CP") allocation methodology.

(2) AE has incorrectly allocated its primary distribution demand-related costs using an average of 12 non-coincident peak ("NCP") demand allocation methodology. Instead, AE's primary distribution demand-related costs should be allocated using the highest monthly NCP (1NCP) demand allocation methodology.

(3) AE has incorrectly allocated primary distribution costs for poles, conductors, and underground ("UG") conduit to the Primary Voltage Above 20 MW at 85% Load Factor customer class.

(4) The cost of street lighting service to the City of Austin ("City") is not charged to the City but rather charged to the other customer classes through the Community Benefit Rider. AE should charge the City for street lighting service.

(5) AE has failed to adjust test year revenues energy sales, demand levels and billing determinants in February 2021 for the Winter Storm Uri outages for some customer classes. This omission will result AE over-recovering its revenue requirement.

(6) In its COSS, AE improperly adjusts customer class demands for losses by applying the energy loss factors from the 2018 System Loss Study.

(7) AE's proposed class COSS results in AE earning a ROR from certain customer classes that is significantly higher than from other customer classes. After correcting for the allocation issues discussed in (1)

through (4) above, the differences in some customer class RORs are even greater.

(8) AE's proposed distribution of its proposed $48.2 million base rate increase to the customer classes results in some customer classes paying substantial subsidies to other customer classes and also results in some customer classes moving further from their cost of service. My recommended revenue distribution addresses these problems and should be approved.

(9) In consideration of Chuck Loy's and my recommendations, we recommend a total, systemwide revenue requirement reduction of approximately $21.79__million, and a reduction in allocated costs to the Primary Voltage Above 20 MW service customer class of $4,551,614________

Q. DOES THIS CONCLUDE YOUR PORTION OF THE POSITION STATEMENT?

A. Yes.

TESTIMONY OF CHUCK E. LOY

PART II

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Charles E. Loy. My business address is 919 Congress Avenue, Suite 1110, Austin, Texas 78701.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I received a Bachelor of Business Administration degree with a concentration in accounting from the University of Texas at Austin. I am a Certified Public Accountant in the State of Texas.

Q. WHAT IS YOUR PRESENT POSITION?

A. I am a Principal for GDS of GDS's office in Austin, Texas.

Q. PLEASE STATE YOUR PROFESSIONAL EXPERIENCE.

A. Prior to joining GDS in June of 2001, I was General Manager of Rates and Regulatory Affairs of AquaSource, Inc. ("AquaSource"). AquaSource is a wholly-owned water and wastewater subsidiary of DQE, Inc., a publicly traded electric utility located in Pittsburgh, Pennsylvania. My responsibilities included the organization, preparation, and management of various rate filings and proceedings on rate requests and other regulatory matters in the twelve states where AquaSource provided water and wastewater utility service. Prior to joining AquaSource, I was a Manager of Regulatory Affairs for Citizens Utilities Company, Public Services Sector ("Citizens"). At Citizens, I was responsible for various regulatory matters, including rate cases for water/wastewater, gas, and electric services in eight states. Prior to joining Citizens, I was a Rate Manager with Southern Union Gas (now Texas Gas Service Company) where I prepared rate filings, cost of service studies, and testimony for their various operations in Texas and Oklahoma. My utility regulation experience began with Diversified Utility Consultants as a Senior Analyst, where I assisted in the review and analysis of various gas, electric, and water company rate filings. My professional resume is included as Exhibit NXP-CEL-8.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. I have testified many times before regulatory commissions. I have submitted testimony before the following state regulatory authorities: the Public Utility Commission of Texas ("PUC" or the "Commission"), the Texas Commission on Environmental Quality, the Texas Railroad Commission, El Paso Public Utilities Board, the Arkansas Public Service Commission, the Arizona Corporation Commission, the Connecticut Department of Public Utility Control, the Delaware Public Service Commission, the Federal Energy Regulatory Commission, the Hawaii Public Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Regulatory Commission, the New Jersey Board of Public Utilities, the Public Service Commission of Montana, the New Mexico Public Service Commission, the New York Public Service Commission, the Public Utilities Commission of Ohio, the Oklahoma Corporation Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of South Carolina, and the West Virginia Public Service Commission. A list of regulatory proceedings in which I have presented expert testimony is provided as Exhibit NXP-CEL-8.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am appearing and providing testimony on behalf of NXP.

PURPOSE OF STATEMENT OF POSITION

Q. WHAT IS THE SUBJECT OF YOUR STATEMENT OF POSITION IN THIS PROCEEDING?

A. I was engaged to review and analyze the portions of AE's base rate filing package related to the proposed revenue requirements. In particular, I have set forth recommendations concerning AE's application of the Cash Flow Methodology in calculating the return component of its revenue requirement.

Q. WOULD YOU PLEASE SUMMARIZE THE RESULTS OF YOUR REVIEW AND ANALYSIS?

A. Based on my review and analysis, I have reached the following conclusions and recommendations regarding AE's application of the Cash Flow Methodology for the return component of its total revenue requirement:

1. I do not agree with the presentation of the cash flow return calculation. I believe it should follow more closely the Non-IOU Transmission Cost of Service Rate Filing Package instructions utilized at the PUC. As a result of applying a corrected methodology, the revenue requirement stays the same, but the imputed rate of return changes and more closely reflects the actual cash flow return requested in AE's rate filing package. This results in a higher imputed rate of return of 13.8% but does not change the revenue requirements.

2. I disagree with the 50% assumption used to determine the Internally Generated Funds for Construction ("IGFFC") level. I recommend a percent level that falls within the City's financial policy and closer to the City's actual average utilization of IGFFC over the last three years of 22%.

3. The level of General Fund Transfer ("GFT") requested is unsupported and its inclusion in rates does not concur with longstanding rate-making principles. As an alternative to AE's proposal I recommend a GFT based on AE's budgeted amount.

4. My recommended adjustments result in a reduction to revenue requirements of $21.79 million, or 1.8%.

ADJUSTMENTS TO AE'S CASH FLOW METHOD RETURN REQUEST

Q. PLEASE DESCRIBE AE'S USE OF THE CASH FLOW APPROACH TO DETERMINE ITS PROPOSED REVENUE REQUIREMENT AND RETURN.

A. The cash flow approach is intended to provide adequate revenue requirements for a MOU to meet its financial needs for ongoing operations and construction of plant. For an investor-owned utility ("IOU"), reasonable and necessary test year operating costs plus a return on the capital investment found to meet the "prudence" standard set forth in statute and Commission rule, based on the application of the utility's weighted average cost of capital to investment in rate base, is used to determine the level of revenue required to attract reasonably cost capital and allow the utility to provide continuous and reliable service. A MOU, having no equity investors, must use a different methodology for this determination. In this case, AE has chosen the cash flow approach.

Under the cash flow method, a MOU's revenue requirement is determined by the sum of operating and maintenance costs, debt service requirements, cash outlays from revenues for capital additions, working capital requirements, bond defeasance costs, and payments to the City for services provided and/or to secure the payment of bonds, less interest income and other income from miscellaneous services the utility provides. These cash needs are generally met by three main funding sources: base rates collected from customers, contributions and payments to the utility from specific customers to fund plant, and the proceeds of debt issuances. The PUC has allowed Non-IOUs to utilize the Cash Flow Method of determining returns. The specific methodology is set forth in the Non-IOU Transmission Cost of Service Rate Filing Package

Q. PLEASE DISCUSS AE'S USE OF THE CASH FLOW APPROACH TO DETERMINE RETURN.

A. AE's proposed cash flow methodology calculation consists of the following components as it appears on Schedule C-3 of AE's rate filing package: Debt Service, Non-Nuclear Decommissioning, GFT, and IGFFC. These items are reduced by Depreciation and Amortization, Interest Income, and Contributions in Aid of Construction ("CIAC").

Q. DO YOU AGREE WITH HOW AE APPLIED THE CASH FLOW METHODOLOGY?

A. While I believe the overall revenue requirement calculated by AE is computationally correct, I disagree with the presentation of the cash flow return. AE includes $146,765,700 in depreciation and amortization ("D&A") expense in the calculation of its revenue requirement on Line 7 of schedule A since D&A expense is not reflected in AEs rates it is not a source of cash and does not affect cash flow. Therefore it should not be included in the calculation of a revenue requirement utilizing a cash flow return. But applying it in the manner AE has proposed departs from that rationale. Accordingly, AE should remove the amount of D&A expense from its calculated return to arrive at the computationally correct revenue requirement.

AE's approach leads to a significant understatement of the true cash flow return that is being requested by the City, and would be embedded in the rates AE is proposing in this proceeding. As shown below on Tables 1 and 2, the actual amount of cash flow being requested by the City is $344,034,416, not the $197,268,716 shown on Line 29 of Schedule A.

Table 1

IOU Cash Flow Using AE Revenue Requirement

1	Requested Revenue Requirement (excludes D&A & before Pass-throughs applied)	$1,337,575,011
2	Total Expenses (Includes D&A & Pass through costs)	$1,140,306,295
3	Cash Flow Return Requested (Line 1 minus Line 2)	$197,268,716
4	Add Back Non-Cash D&A	$146,765,700
5	Cash Flow Method Reflected In AE Request	**$344,034,416**

Table 2

Alternative PUC Non-IOU Cash Flow Return Method

		AE Requst	Adjust	As Adjusted
		(a)	(b)	(c)
Overall Revenue Requiemrent				
1	Total Expenses	$1,140,306,295	($146,765,700)	$993,540,595
2	Requested Return (Calculated below)	$197,268,716	$146,765,700	$344,034,416
3	Total Rev Req (before Pass-throughs)	$1,337,575,011		$1,337,575,011
Cash Flow Return Calculation				
4	Debt Service	$143,115,070		$143,115,070
5	Non-Nuclear Decommissioning	$8,000,000		$8,000,000
6	General Fund Transfer	$121,000,000		$121,000,000
7	Internally Generated Funds for Construc	$119,817,642		$119,817,642
8	Depreciation & Amortization	($146,765,700)	$146,765,700	$0
9	Interest and Dividend Income	($4,270,316)		($4,270,316)
10	Contribution in Aid of Construction	($43,627,981)		($43,627,981)
11	Total Return	$197,268,716		$344,034,416
12	Rate Base	$2,488,130,769		$2,488,130,769
13	Rate of Return - Line 11/Line 12	**7.9%**		**13.8%**

Q. TABLE 2 ABOVE SHOWS A TRUE PROPOSED RATE OF RETURN OF 13.8%. DO YOU HAVE ANY ADDITIONAL COMMENTS ON THIS AMOUNT?

A. I would note that the imputed 13.8% is a cash flow return and is not comparable to a return that would be granted to a regulated IOU, as it excludes the effect of depreciation and amortization (as noted above). However I believe that this measure is a better indicator of the amount of the cash that AE is actually requesting, above that which is needed to fund ongoing non-capital operations.

ADJUSTMENTS TO AE'S CASH FLOW RETURN COMPONENT

Internally Generated Funds for Construction (IGFFC)

Q. PLEASE EXPLAIN THE SIGNIFICANCE OF INTERNALLY GENERATED FUNDS.

A. Internally generated funds are the amount of revenue collected from customers that is used, in conjunction with funds received from issuances of debt, for construction, improvements, and replacements. The AE financial policy on IGFFC characterizes it as an equity contribution. Capital policy No. 14 found in Appendix B of the rate filing package states:

> "Capital projects should be financed through a combination of cash, referred to as pay-as-you-go financing (equity contributions from current revenues), and debt. An equity contribution ratio between 35% and 60% is desirable."

Q. HOW DID AE COMPUTE THE IGFFC?

A. The relevant schedule shows that AE is using a cash funding assumption of 50%. AE's analysis looks at two prior years, 2019 and 2020, plus the 2021 test year to develop the known and measurable amount of $119.8 million.[12]

[12] *See* Schedule WP C-3.3.1, Line 69

Q. DO YOU AGREE WITH AE'S IGFFC ADJUSTMENT?

A. I agree with the overall methodology for determining the IGFFC amount but do not agree with the 50% equity funding assumption.[13] The AE workpaper shows that in FY2019, FY2020, and FY2021 the percentage of construction that was debt-funded was 85.1%, 53.2%, and 46.2% respectively, resulting in a three-year average of 67.2%. CIACs provided an average of 11% of funding over the same time period. Therefore, the actual proportion of capital costs that was funded through base rate revenues only averaged 22% during the last three years.

Q. DOES THE 50% IN EQUITY FUNDING INCLUDE CIAC?

A. No. Referencing the total Cash to Fund Capital Spending shown on the workpaper the total equity (i.e. non-debt) funding that would be provided by customers ranges between 54% and 59% for the FY2019 through FY2021 period, averaging 56%, or close to the top of the range provided in AE's financial policy guidance above.[14]

Q. WHAT IS YOUR RECOMMENDATION FOR THE CASH FUNDING ASSUMPTION TO BE USED IN THE CALCULATION OF IGFFC?

A. I recommend that the cash funding assumption within AE's model be set to 35%, which would reduce the IGFFC included in AE's cash flow return from $119,817,642 to $96,960,744 as shown in Table 3 below. This would result in an overall equity contribution to fund construction of 43%, well within AE's financial policy range.

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13 *See* Schedule WP C-3.3.1
14 *See* Schedule WP C-3.3.1, Line No. 66

Table 3

Adjustment to Internally Generated Funds for Construction

IGFFC Assuming 50% Equity Contribution As Proposed	$ 119,817,642
IGFFC Assuming 35% Equity Contribution as Recommended	96,960,744
Recommended Adjustment	(22,856,898)

General Fund Transfer (GFT)

Q. DOES YOUR PUC METHODOLOGY CASH FLOW RETURN COMPUTATION ALLOW AE TO MAKE GENERAL FUND TRANSFERS ?

A. Yes, within certain limits. The PUC's instructions (Exhibit NXP-CEL-9) in the Non-IOU Transmission Cost of Service Rate Filing Package available online on the PUC's website states:

> "...for municipal utilities, annual payments for transfers to the City's general fund at rates established by the municipal utility's governing authority, to the extent such amounts are not recovered through other elements of the TCOS…"[15]

The instructions indicate the GFTs should be a reimbursement for the costs of services related to the provision of *providing utility services* or costs that could otherwise be recovered in the TCOS. Many MOUs receive administrative services such as human resources, financial and accounting, office maintenance, etc. from their host Cities. These costs will be reimbursed to the City via transfer to the City's General Fund.

Q. DOES THE CITY OF AUSTIN PROVIDE ADMINISTRATIVE SERVICES TO AE?

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15 Accessible at HTTPS://WWW.PUC.TEXAS.GOV/INDUSTRY/ELECTRIC/FORMS/RFP/NON_IOU_TCOS_INSTR.PDF

A. Yes. AE includes over $62 million of charges from City Services.[16] These expenses were included with other O&M expenses rather than the Cash Flow Method return calculation. The AE base rate filing package states: "Austin Energy transfers funds to the City for its share of services such as the City Fleet Department, Law Department and Administrative Support and Communications and Technology Management".

Q. DOES THE GFT IN THE CASH FLOW RETURN CALCULATION REFLECT CITY OF AUSTIN SERVICES TO AE FOR THE PROVISION OF UTILITY SERVICE?

A. No. The "Austin Energy 2022 Base Rate Filing Package" at page 34, states the following regarding the amount of GFT in the return calculation:

> "Consistent with standard practice among MOUs and Texas Government Code subsection 1502.059, Austin Energy transfers a percentage of revenues to the City. Austin Energy makes transfers to the City's general fund in lieu of paying franchise fees, taxes, dividends; and also in lieu of earning a return on investment. The transfer payment from Austin Energy to the City is invested directly back into the local community, rather than flowing to outside investors, which is a benefit to residents in Austin and those in surrounding communities."

AE's description does not indicate how the specific $121 million amount was determined; it only indicates that the GFT charge represents a proxy for the taxes, dividends, and returns or costs it is not required to pay. The GFT charge received will be invested back into "the local community rather than flowing to outside investors." Essentially, the GFT as supported by AE appears to be for an unspecified non-utility purpose and its inclusion in rates would not follow rate-making standards common to the electric utility industry.

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16 See Schedule WP D-1.2.5

Additionally, AE provides no support for its contention that the GFT is invested directly back into the local community.

Q. THE AE FILING PACKAGE DESCRIPTION ABOVE CITES TEXAS GOVERNMENT CODE SUBSECTION 1502.059. DOES THIS PROVISION ALLOW FOR GENERAL FUND TRANSFERS THAT ARE UNSPECIFIED?

A. The code cited by the Austin package is as follows:

> Texas Gov. Code – Sec. 1502.059, Transfer of Revenue to General Fund
>
> Notwithstanding Section 1502.058 (Limitation on Use of Revenue) (a) or a similar law or municipal charter provision, a municipality and its officers and utility trustees may transfer to the municipalities general fund and may use for general or special purposes revenue of any municipality owned system in the amount and **to the extent authorized in the indenture, deed of trust, or ordinance providing for and securing payment of public securities issued under this chapter or similar law. (emphasis added)**

My understanding of the above code sections, based upon my knowledge as an expert in the field of municipal utility regulations, rates, and funding, is that it relates to payments to a City's general fund authorized by bond ordinances that secure the payment of bonds and other expenses related to securities, bond defeasance, or a cash infusion to help the City meet its debt coverage covenants. There is no mention of these types of payments in AE's description, however. n a complaint of a water utility against the City of Austin that is instructive here, the former Texas Water Commission (whose rate regulatory functions have been reassigned to the PUC) held that municipal utility transfers to a city's general fund are acceptable if they reimburse the city for administrative expenses. However, ***unspecified*** transfers to the general fund would be justifiable only if they are needed to provide the city with adequate debt service coverage.[17] In addition, there is a similar finding in SOAH Docket No. 473-14-5138.WS, PUC Docket No. 42857. [18] Page 35 of the Proposal for Decision states the following:

> "The M1 Manual also states that payments made to a municipality's general fund should reimburse the general fund for the necessary cost of goods or services required by the water utility to provide water service. Following this reasoning, the general transfer should not be used to set Petitioners' rates when the cost has not been shown by the evidence to the related to providing service to Petitioners. Otherwise, ratepayers outside the City's limits are being charged rates that include an allocated portion of the 8.2% transfer into the City's general fund, which may then be used to provide general services to the City's residents."

Q. THE DECISIONS YOU CITE ABOVE ARE RELATED TO WATER UTILITIES, NOT ELECTRIC, AND WERE BROUGHT BY CUSTOMERS OUTSIDE OF AUSTIN CITY LIMITS. WHY DO YOU BELIEVE THIS IS RELEVENT TO ELECTRIC CUSTOMERS INSIDE THE CITY LIMITS WHO ARE CITIZENS OF THE CITY OF AUSTIN?

A. Though the decisions cited above disallowed GFT because they were not being used for utility service to outside customers, the same principles apply to utility service for customers inside city limits as well. Both decisions were made under the guidance of the same ratemaking principles that are applicable to this request, that the cost of providing utility service should be the basis of rates. AE's rate filing package explicitly states that the transfer is not for utility services, and nowhere indicates how the funds will be used "for and securing payment of public securities" to assist the City. If this procedure is to follow

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[17] Pet. Ex. 5 at 25; JJJ-5 at 949-50; TWC Docket No. 7144-M, *In the Matter of Complaints of Springwoods* ***Municipal*** *Utility District,* ***et al. against*** *the City of Austin,* Findings of Fact Nos. 40 and 41.

[18] *Petition of the North Austin Municipal Utility District No. 1, Northtown Municipal Utility District, Travis County Water Control And Improvement District No. 10, and Wells Branch Municipal Utility District From The Ratemaking Actions of the City of Austin and Requests for Interim Rates In Williamson and Travis Counties.*

longstanding ratemaking principles founded on economic standards common to the utility industry, then based on the evidence provided the GFT should properly be excluded.

Q. AE INDICATES THE INCLUSION OF THE GFT IS "STANDARD PRACTICE AMONG MOUS" AND IMPLIES THIS IS PERMITTED UNDER TEXAS GOVERNMENT CODE SEC. 1502.059.

A. I am not qualified to challenge whether the GFT as proposed is properly following the law, only its reasonableness as applied under longstanding ratemaking principles. I have difficulty reconciling what is stated in Texas Government Code Sec. 1502.059 and AE's justification for GFT inclusion in rates. Regardless, it has been established in PUC decisions that transfers just like AE's GFT as proposed should not be recovered in rates assessed to its outside customers. The City's unspecified investments in the local community is hardly a dividend to customers. And for the AE customers located outside the city limits, AE fails to describe any benefit at all for their monthly "investment" in the City of Austin. As proposed, it appears that the GFT is a backdoor tax on customers both outside and inside the City of Austin's city limits. Many communities in Texas would require a vote from informed citizens on a $121 million tax.

Q. WHAT IS THE IMPACT OF THE GFT ON THE BASE RATES AS PROPOSED?

A. The GFT represents about 18% of requested base rate revenues. Under AE's proposed rate design, I estimate NXP will pay about $7.3 million of the GFT. The average bill impact of the GFT on AE residential customers, both inside and outside the City limits, is estimated at about $139.00 per customer annually. This reflects about $8.7 million paid by outside residential customers assuming an estimated total amount to the residential class of $62 million.

Q. YOU INDICATED EARLIER THAT YOU ARE PROPOSING AN ALTERNATIVE RECOMMENDATION FOR THE GFT INSTEAD OF OUTRIGHT DISALLOWING THE GFT EXPENSE. PLEASE EXPLAIN YOUR ALTERNATIVE.

A. Yes. The GFT transfer shown in the City's latest budget document awaiting approval of the City Council would support the inclusion of a maximum of $114 million in GFT, not the $121 million requested by AE in this proceeding. I recommend that the amount of GFT included in rates be set at $114 million, a $7 million reduction from what was requested by AE.

Q. DO YOU HAVE ANY RECOMMENDATIONS IF THE FULL $121 MILLION GFT REQUESTED IN ITS RATE FILING PACKAGE IS APPROVED?

A. Yes. If only $114 million is transferred, that represents $7 million in cash that AE will collect in rates that will not be transferred to the general fund. The financial policy adopted by AE requires that the transfer to GFT be based on the three-year average revenues (less PSA revenues) times 12%. AE's request is based on a percentage of the ***cost of service*** calculated in this case, ignoring previous years. Therefore the rates necessary to support the amount of transfer included in AE's request will not be fully included in the calculation as detailed in the AE financial policy until three years from now, resulting in a windfall for the utility. I recommend that if the entire GFT amount of $121 million is approved, the requested funding for the non-nuclear decommissioning reserve should be reduced by the difference between what will be collected in rates and the actual GFT transfer to the City (i.e. $7 million in the first year of the increased rates).

SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. The table below shows the effect of my adjustments on AE's overall revenue requirement.

Table 5

NXP Revenue Requirement Position

Line No.	Revenue Requirement Component	AE As Filed	AE As Corrected	NXP Recommended	Change - As Corrected to Recommended $	Change - As Corrected to Recommended %
	(a)	(b)	(c)	(d)	(e)	(f)
1	Total Expenses	$ 1,140,306,295	$ 993,540,595	$ 993,540,595	$ -	0.0%
2	*Cash Flow Return Calculation*					
3	Debt Service	143,115,070	143,115,070	143,115,070	-	0.0%
4	Non-Nuclear Decommissioning	8,000,000	8,000,000	8,000,000	-	0.0%
5	General Fund Transfer	121,000,000	121,000,000	114,000,000	(7,000,000)	-5.8%
6	Internally-Generated Funds for Construction	119,817,642	119,817,642	96,960,744	(22,856,898)	-19.1%
7	Less: Depreciation & Amortization	(146,765,700)	-	-	-	n/a
8	Less: Interest and Dividend Income	(4,270,316)	(4,270,316)	(4,270,316)	-	0.0%
9	Less: Contribuions in Aid of Construction	(43,627,981)	(43,627,981)	(43,627,981)	-	0.0%
10	Total Cash Flow Return Requested	197,268,716	344,034,416	314,177,517	(29,856,898)	-8.7%
11	Less: Other Revenue	(144,435,404)	(144,435,404)	(136,368,862)	8,066,543	-5.6%
12	**Total Revenue Requirement**	**1,193,139,607**	**1,193,139,607**	**1,171,349,251**	**(21,790,356)**	**-1.8%**

Q. DOES THIS CONCLUDE YOUR PORTION OF THE STATEMENT OF POSITION?

A. Yes it does.

EXHIBITS

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
1/1/1976	Federal Power Commission	ER76-530	Arizona Public Service Company
2/76	South Dakota Public Utility Commission	F-3055	Northwestern Public Service Company
5/79	Federal Energy Regulatory Commission	78-379; 380; 381; 382; 383	Indiana & Michigan Electric Company
11/80	New Mexico Public Service Commission	1627	Kit Carson Electric Cooperative (Direct Testimony)
6/81	Arizona Corporation Commission	9962-E-1032	Citizens Utilities Company
9/81	Federal Energy Regulatory Commission	ER81-179	Arizona Public Service Commission (Direct Testimony)
3/84	Texas Public Utility Commission	5640	Texas Utilities Electric Company
4/2/1984	Public Utility Commission of Texas	5560	Gulf States Utility Company (Direct Testimony)
7/3/84	Texas Public Utility Commission	5640	Texas Utilities Electric Company (Direct Testimony)
11/15/1984	Texas Public Utility Commission	5709	Texas Utilities Electric Company (Direct Testimony)
1/85	Federal Energy Regulatory Commission	ER84-568-000	Gulf States Utilities Company (Direct Testimony)
11/20/1985	Federal Energy Regulatory Commission	ER85-538-001	Gulf States Utilities Company (Direct Testimony)
1/7/86	Louisiana Public Service Commission	U-16510	Central Louisiana Electric Company (Direct Testimony)
3/10/86	Texas Public Utility Commission	6677	Texas Utilities Electric Company
3/14/86	Federal Energy Regulatory Commission	ER85-538-001	Gulf States Utilities Company Rebuttal and Surrebuttal Testimony)
6/20/88	Texas Public Utility Commission	8032	Lower Colorado River Authority (Direct Testimony)
7/15/88	Texas Public Utility Commission	8032	Lower Colorado River Authority (Supplemental Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
3/7/90	Texas Public Utility Commission	9165	El Paso Electric Company (Direct Testimony)
4/12/90	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Direct Testimony - Revenue Requirements Phase)
5/1/90	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Direct Testimony - Phase II - Rate Design)
7/6/90	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Supplemental Testimony - Revenue Requirements)
7/10/90	Texas Public Utility Commission	9427	Lower Colorado River Authority (Direct Testimony - Rate Design)
7/30/90	Texas Public Utility Commission	9427	Lower Colorado River Authority (Rebuttal Testimony - Rate Design)
8/23/90	Texas Public Utility Commission	9561	Central Power & Light Company (Direct Testimony - Rate Design)
1/11/91	Texas Public Utility Commission	9427	Lower Colorado River Authority (Rebuttal Testimony)
9/24/91	Texas Public Utility Commission	10404	Guadalupe Valley Electric Cooperative (Direct Testimony)
12/91	Rate Area 2&3 Nebraska Municipalities	N/A	Peoples Natural Gas Company
7/31/92	Texas Public Utility Commission	11266	Guadalupe-Blanco River Authority (Direct Testimony)
8/7/92	State Corporation Commission of Kansas	180,416-U	Peoples Natural Gas Company (Direct Testimony)
9/8/92	Texas Public Utility Commission	11266	Guadalupe-Blanco River Authority (Direct Testimony)
9/92	Texas Public Utility Commission	10894	Gulf States Utilities Company (Direct Testimony)
5/93	Texas Public Utility Commission	11735	Texas Utilities Electric Company (Rebuttal Testimony)
6/93	Texas Public Utility Commission	11892	Generic Proceeding Regarding Purchased Power (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
09/08/93	State Corporation Commission of Kansas	186,363-U	KN Energy (Direct Testimony)
09/94	State Corporation Commission of Kansas	190,362-U	Kansas Natural Pipeline and Kansas Natural Partnership (Direct Testimony)
10/17/94	Texas Public Utility Commission	12820	Central Power and Light Company (Direct Testimony)
11/15/1994	City of Houston	NA	Houston Lighting and Power Company (Direct Testimony)
11/15/1994	Texas Public Utility Commission	12065	Houston Lighting and Power Company (Direct Testimony - Revenue Requirements Phase)
12/12/1994	Texas Public Utility Commission	12820	Central Power & Light Company (Supplemental Testimony)
1/10/1995	Texas Public Utility Commission	12065	Houston Lighting & Power Company (Direct Testimony - Rate Design Phase)
5/23/95	Federal Energy Regulatory Commission	TX94-4-000	Texas Utilities Electric Company and Southwestern Electric Service (Affidavit)
8/7/95	Texas Public Utility Commission	13369	West Texas Utilities Company Rebuttal Testimony - Rate Design Phase)
10/31/95	Texas Public Utility Commission	14435	Southwestern Electric Power Company (Direct Testimony)
11/95	Rate Area 3 Nebraska Municipalities	N/A	Peoples Natural Gas Company (Municipal Report)
02/07/96	Federal Energy Regulatory Commission	TX96-2-000	City of College Station, Texas (Affidavit)
5/15/1996	Texas Public Utility Commission	14965	Central Power & Light Company (Direct Testimony)
5/29/1996	Texas Public Utility Commission	14965	Central Power & Light Company (Rebuttal Testimony)
07/19/96	Texas Public Utility Commission	15766	City of Bryan, Texas (Direct Testimony)
8/29/1996	Texas Public Utility Commission	15296	City of Bryan, Texas (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
08/07/96	State of Illinois Commerce Commission	96-0245 & 96-0248	Commonwealth Edison Company (Direct Testimony)
09/06/96	Texas Public Utility Commission	15643	Central Power & Light Company and West Texas Utilities Company (Direct Testimony)
9/17/1996	Texas Public Utility Commission	15296	City of Bryan, Texas (Rebuttal Testimony)
09/18/96	Texas Public Utility Commission	15638	Texas Utilities Electric Company (Direct Testimony)
10/22/96	Texas Natural Resource Conservation Commission	96-0652-UCR	Longbranch Associates, L.P. (Direct Testimony)
08/05/97	Arkansas Public Service Commission	97-019-U	Arkansas Western Gas Company (Direct Testimony)
08/06/97	Texas Public Utility Commission	16705	Entergy Texas (Direct Testimony)
08/25/97	Texas Public Utility Commission	16705	Entergy Texas (Rebuttal Testimony - Rate Design Phase)
09/23/97	Arkansas Public Service Commission	97-019-U	Arkansas Western Gas Company Surrebuttal Testimony
09/30/97	Texas Public Utility Commission	16705	Entergy Texas (Direct Testimony - Competitive Issues Phase)
12/97	United States Tax Court	7685-96 and 4979-97	Lykes Energy, Inc. (Report)
12/97	Condemnation Court Appointed by the Supreme Court of Nebraska	13880	Peoples Natural Gas
12/1/1997	Condemnation Court Appointed by the Supreme Court of Nebraska	NA	Peoples Natural Gas Company (Report to City of Wahoo, Nebraska)
8/1/1998	Condemnation Court Appointed by the Supreme Court of Nebraska	101	Peoples Natural Gas (Report to City of Scribner, Nebraska)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
10/98	Federal Energy Regulatory Commission	EL-99-6-000	Entergy Gulf States, Inc. (Affidavit)
10/19/1998	Federal Energy Regulatory Commission	TX98-	Gulf States Utilities Company (Affidavit)
12/31/1998	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Direct Testimony)
3/11/1999	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Supplemental Testimony)
4/30/1999	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Rebuttal Testimony)
7/16/1999	Texas Public Utility Commission	19265	Central and South West Corporation and American Electric Power Company, Inc. (Direct Testimony)
11/1/1999	Texas Public Utility Commission	21591	Sharyland Utilities, L.P. (Direct Testimony)
11/24/1999	Texas Public Utility Commission	21528	Central Power and Light Company (Direct Testimony)
1/27/2000	Texas Railroad Commission	8976	Texas Utilities Company Lone Star Pipeline (Direct Testimony)
3/31/2000	Texas Public Utility Commission	22348	Sharyland Utilities, L.P. (Direct Testimony)
08/2000	Texas Public Utility Commission	20624	Reliant Energy HL&P (Direct Testimony)
10/16/2000	Texas Public Utility Commission	22344	Generic Issues Associated with Unbundled Cost of Service Rate (Direct Testimony)
10/23/2000	Texas Public Utility Commission	21956	Reliant Energy, Inc. (Direct Testimony)
11/14/2000	Texas Public Utility Commission	22350	TXU Electric Company (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
11/17/2000	Texas Public Utility Commission	22352	Central Power and Light Company (Direct Testimony)
12/12/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Direct - Final Phase) (Direct Testimony)
12/21/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Direct Testimony - Rate Case Expense Phase)
12/29/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Supplemental & Rebuttal Testimonies)
7/5/2001	Texas Public Utility Commission	23950	Reliant Energy (Direct Testimony)
9/6/2001	Texas Public Utility Commission	24239	Mutual Energy CPL, LP (Direct Testimony)
4/22/2002	State Corporation Commission of Kansas	02-WSRE-301-RTS	Western Resources, Inc. and Kansas Gas and Electric Company (Direct Testimony)
6/19/2002	Federal Energy Regulatory Commission	TX96-2-000	City of College Station, Texas (Direct Testimony)
8/5/2002	Oklahoma Corporation Commission	200100455	Oklahoma Gas and Electric Company (Responsive Testimony)
12/31/2002	Texas Public Utility Commission	26195	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
4/24/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Rebuttal Testimony)
6/9/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Supplemental Direct Testimony)
7/11/2003	State Corporation Commission of Kansas	03-KGSG-602-RTS	Kansas Gas Service, a Division of ONEOK, Inc. (Direct Testimony)
8/11/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Second Supplemental Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
8/18/2003	State Corporation Commission of Kansas	03-KGSG-602-RTS	Kansas Gas Service, a Division of ONEOK, Inc. (Supplemental Testimony)
10/29/2003	Federal Energy Regulatory Commission	ER04-35-000	Entergy Services, Inc. (Affidavit)
11/5/2003	Texas Public Utility Commission	26195	CenterPoint Energy Houston Electric, LLC (Supplemental Direct Testimony)
2/9/2004	Texas Public Utility Commission	28840	AEP Texas Central Company (Direct Testimony)
6/1/2004	Texas Public Utility Commission	29526	CenterPoint Energy Houston Electric, LLC, Reliant Energy Retail Services, LLC, and Texas Genco, LP (Direct Testimony)
8/19/2004	Texas Public Utility Commission	28813	Cap Rock Energy Corporation (Affidavit)
8/30/2004	Texas Public Utility Commission	28813	Cap Rock Energy Corporation (Direct Testimony)
1/7/2005	Texas Public Utility Commission	30485	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
3/16/2005	Texas Public Utility Commission	30706	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
6/9/2005	Texas Public Utility Commission	29801	Southwestern Public Service Company (Direct Testimony)
9/2/2005	Texas Public Utility Commission	31056	AEP Texas Central Company and CPL Retail Energy, LP (Direct Testimony)
9/9/2005	State Corporation Commission of Kansas	05-WSEE-981-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
9/29/2005	Georgia Public Service Commission	20298-U	Atmos Energy Corporation (Direct Testimony)
4/24/2006	Texas Public Utility Commission	32475	AEP Texas Central Company (Cross Answering Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
8/11/2006	Texas Public Utility Commission	32093	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
8/23/2006	Texas Public Utility Commission	32795	Reallocation of Stranded Costs Pursuant to PURA §139.253(f) (Direct Testimony)
8/24/2006	Texas Public Utility Commission	32758	AEP Texas Central Company (Direct Testimony)
12/22/2006	Texas Public Utility Commission	32766	Southwestern Public Service Company (Direct Testimony)
3/13/2007	Texas Public Utility Commission	33309	AEP Texas Central Company (Direct Testimony)
3/19/2007	State Corporation Commission of Kansas	07-AQLG-431-RTS	Aquila Networks-KGO (Direct Testimony)
4/27/2007	Texas Public Utility Commission	33687	Entergy Gulf States, Inc. (Direct Testimony)
7/11/2007	Texas Public Utility Commission	33823	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
7/13/2007	Texas Public Utility Commission	33687	East Texas Cooperatives (Supplemental Testimony)
1/11/2008	Texas Public Utility Commission	35219	Guadalupe Valley Electric Cooperative, Inc (Direct Testimony)
1/29/2008	Texas Public Utility Commission	35287	Sharyland Utilities, L.P. (Direct Testimony)
7/1/2008	Georgia Public Service Commission	27163	Atmos Energy Corporation (Direct Testimony)
9/16/2008	Texas Public Utility Commission	34442	JD Wind (Direct Testimony)
9/29/2008	State Corporation Commission of the State of Kansas	08-WSEE-1041-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
10/13/2008	Texas Public Utility Commission	35763	Southwestern Public Services Company (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
11/26/2008	Texas Public Utility Commission	35717	Oncor Electric Delivery Company (Direct Testimony)
6/26/2009	State Corporation Commission of the State of Kansas	09-WSEE-641-GIE	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
6/29/2009	Texas Public Utility Commission	36918	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
9/30/2009	State Corporation Commission of the State of Kansas	09-WSEE-925-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
7/10/2010	Pennsylvania Public Utility Commission	R-2010-2161575, et. al.	PECO Energy Company (Direct Testimony)
9/3/2010	Texas Public Utility Commission	38324	Oncor Electric Delivery Company, LLC (Direct Testimony)
9/10/2010	Texas Public Utility Commission	38339	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
9/24/2010	Texas Public Utility Commission	38339	CenterPoint Energy Houston Electric, LLC (Cross-Rebuttal Testimony)
9/27/2010	Texas Public Utility Commission	38324	Oncor Electric Delivery Company, LLC (Cross-Rebuttal Testimony)
11/5/2010	Texas Public Utility Commission	38577	PUCT Modification of CREZ Transmission Plan (Direct Testimony)
2/4/2011	Texas Railroad Commission	GUD 10038	CenterPoint Energy Texas Gas (Direct Testimony)
3/1/2011	Texas Public Utility Commission	39070	Sharyland Utilities, L.P. (Direct Testimony)
10/19/2011	Texas Public Utility Commission	39856	Guadelupe Valley Electric Cooperative (Direct Testimony)
5/1/2012	Texas Public Utility Commission	40364	Sharyland Utitilies, L.P. (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
5/15/2012	Delaware Public Service Commisison	11-528	Delmarva Power & Light Company (Direct Testimony)
11/2/2012	Florida Public Service Commission	120015-EI	Florida Power & Light Company (Direct Testimony)
2/20/2013	Texas Public Utility Commission	40627	Homeowners United for Rate Fairness (Cross-Rebuttal Testimony)
4/30/2013	Texas Public Utility Commission	41438	Sharyland Utilities, L.P. (Direct Testimony)
5/31/2013	Texas Public Utility Commission	41474	Sharyland Utilities, L.P. (Direct Testimony)
8/27/2013	Texas Public Utility Commission	41794	Sharyland Utilities, L.P. (Direct Testimony)
11/7/2013	Texas Public Utility Commission	41474	Sharyland Utilities, L.P. (Rebuttal Testimony)
1/2/2014	Texas Public Utility Commission	42133	Sharyland Utilities, L.P. (Direct Testimony)
1/9/2014	Michigan Public Service Commission	U-17437	DTE Electric Company (Direct Testimony)
5/19/2014	Public Service Commission of West Virginia	14-0344-E-GI	SWVA, Inc. (Direct Testimony)
6/17/2014	Texas Public Utility Commission	42087	Oncor Electric Delivery Company (Direct Testimony)
7/23/2014	Texas Public Utility Commission	42699	Sharyland Utilities, L.P. (Direct Testimony)
8/6/2014	Virginia State Corporation Commission	2014-00026	Steel Dynamics, Inc. (Direct Testimony)
8/15/2014	Texas Public Utility Commission	42767	Sharyland Utilities, L.P. (Direct Testimony)
12/18/2014	Public Service Commission of West Virginia	14-1152-E-42T	SWVA, Inc. (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
1/23/2015	Texas Public Utility Commission	44361	Sharyland Utilities, L.P. (Direct Testimony)
2/10/2015	Texas Public Utility Commission	44438	Sharyland Utilities, L.P. (Direct Testimony)
4/8/2015	Texas Public Utility Commission	44620	Sharyland Utilities, L.P. (Direct Testimony)
5/13/2015	Regulatory Commission of Alaska	U-14-111	Municipal Light & Power, Municipality of Anchorage (Direct Testimony)
5/19/2015	West Virginia Public Service Commission	15-0301-E-GI	SWVA, Inc. (Direct Testimony)
6/15/2015	Oregon Public Utility Commission	UE 294	Industrial Customers of Northwest Utilities (Direct Testimony)
9/8/2015	Texas Public Utility Commission	44620	Sharyland Utilities, L.P. (Rebuttal Testimony)
10/23/2015	Oklahoma Corporation Commission	201500208	Public Service Company of Oklahoma (Responsive Testimony)
12/11/2015	Texas Public Utility Commission	44941	El Paso Electric Company (Direct Testimony)
1/11/2016	Texas Public Utility Commission	44941	El Paso Electric Company (Supplemental Testimony)
3/21/2016	Oklahoma Corporation Commission	201500273	Oklahoma Gas & Electric Company (Responsive Testimony)
3/31/2016	Oklahoma Corporation Commission	201500273	Oklahoma Gas & Electric Company (Responsive Testimony)
4/20/2016	Texas Public Utility Commission	45875	Sharyland Utilities, L.P. (Direct Testimony)
4/29/2016	Texas Public Utility Commission	45414	Sharyland Utilities, L.P. (Direct Testimony)
6/29/2016	West Virginia Public Service Commission	15-1734-E-T-PC	SWVA, Inc. (Direct Testimony)
8/4/2016	Texas Public Utility Commission	46236	Sharyland Utilities, L.P. (Direct Testimony)
12/6/2016	Texas Public Utility Commission	46042	City of Lubbock (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
12/28/2016	Texas Public Utility Commission	46710	Guadalupe Valley Electric Cooperative, Inc. (Direct Testimony)
12/30/2016	Texas Public Utility Commission	45414	Sharyland Utilities, L.P. & SDTS, LLC (Direct Testimony)
2/7/2017	Regulatory Commission of Alaska	U-16-066	ENSTAR Natural Gas Company (Responsive Testimony)
3/7/2017	Texas Public Utility Commission	45414	Sharyland Utilities, L.P. & SDTS, LLC (Rebuttal Testimony)
4/6/2017	Public Service Commission of Utah	16035-036	Questar Gas Company (Direct Testimony)
4/27/2017	Public Service Commission of Utah	16035-036	Questar Gas Company (Rebuttal Testimony)
6/23/2017	Texas Public Utility Commission	46831	El Paso Electric Company (Direct Testimony)
7/21/2017	Texas Public Utility Commission	46831	El Paso Electric Company (Cross Rebuttal Testimony)
10/2/2017	Texas Public Utility Commission	46936	Golden Spread Electric Cooperative, Inc. (Direct Testimony)
10/7/2017	Texas Public Utility Commission	47576	City of Lubbock (Direct Testimony)
12/4/2017	Texas Public Utility Commission	47461	Southwestern Electric Power Company (Direct Testimony)
1/4/2018	Texas Public Utility Commission	47576	City of Lubbock (Rebuttal Testimony)
6/29/2018	Pennsylvania Public Utility Commission	R-2018-3000124	Duquesne Light Company (Rebuttal Testimony)
8/6/2018	Pennsylvania Public Utility Commission	R-2018-3000124	Duquesne Light Company (Surrebuttal Testimony)
1/14/2019	Railroad Commission of Texas	10779	Atmos Energy Corporation (Direct Testimony)
10/28/2019	Texas Public Utility Commission	49849	El Paso Electric Company (Direct Testimony)
11/14/2019	Utah Public Utility Commission	19-057-02	Dominion Energy Utah (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
12/13/2019	Utah Public Utility Commission	19-057-02	Dominion Energy Utah (Rebuttal Testimony)
1/6/2020	Utah Public Utility Commission	19-057-02	Dominion Energy Utah (Surrebuttal Rebuttal Testimony)
1/14/2020	Texas Public Utility Commission	49737	Southestern Electric Power Company (Direct Testimony)
2/13/2020	Federal Energy Regulatory Commission	RP19-1353	Northern Natural Gas Company (Answering Testimony)
3/23/2021	Texas Public Utility Commission	51611	Sharyland Utilities, L.L.C. (Direct Testimony)
3/31/2021	Texas Public Utility Commission	51415	Southwestern Electric Power Company (Direct Testimony)
10/22/2021	Texas Public Utility Commission	51409	CPS Energy Company (Direct Testimony)
10/22/2021	Texas Public Utility Commission		El Paso Electric Company (Direct Testimony)
11/19/2021	Texas Public Utility Commission		El Paso Electric Company (Cross-Rebuttal Testimony)

Work Paper F-6.1
Normalized Load Research Data

WP F-6.1

No.	Description		Reference	Residential	Secondary Voltage < 10 kW	Secondary Voltage ≥ 10 < 300 kW	Secondary Voltage ≥ 300 kW	Primary Voltage < 3 MW	Primary Voltage ≥ 3 < 20 MW	Primary Voltage ≥ 20 MW @ 85% aLF	Transmission	Transmission Voltage ≥ 20 MW @ 85% aLF	Service Area Street Lighting	City-Owned Private Outdoor Lighting	Customer-Owned Non-Metered Lighting	Customer-Owned Metered Lighting	Total
				(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
1	Coincident Peak (kW)																
2		Oct-20		1,123,748	36,230	389,433	292,554	44,574	114,690	195,788	3,231	28,326	-	-	-	424	2,229,000
3		Nov-20		662,167	34,041	363,965	324,087	42,794	113,040	187,027	3,207	27,270	-	-	-	401	1,758,000
4		Dec-20		731,981	60,230	433,336	342,558	45,572	111,063	176,979	2,653	25,052	4,544	913	147	972	1,936,000
5		Jan-21		895,141	66,660	448,098	316,846	37,562	106,547	178,913	2,432	25,394	5,378	1,081	174	774	2,085,000
6		Feb-21		1,322,838	78,822	463,723	326,881	39,551	105,515	172,901	2,509	23,123	11,335	2,833	454	514	2,551,000
7		Mar-21		705,976	28,968	290,199	229,878	31,681	110,656	186,680	2,700	26,948	-	-	-	315	1,614,000
8		Apr-21		978,094	37,931	415,732	321,440	43,398	118,054	190,763	2,066	27,681	-	-	-	841	2,136,000
9		May-21		1,083,351	44,306	491,156	363,097	49,962	114,816	195,878	2,447	28,386	-	-	-	602	2,374,000
10		Jun-21		1,329,194	51,417	523,677	372,869	56,099	121,165	195,552	26,741	28,739	-	-	-	548	2,706,000
11		Jul-21		1,321,009	51,713	548,075	367,448	51,430	117,749	196,152	3,350	28,550	-	-	-	525	2,686,000
12		Aug-21		1,325,210	59,363	552,847	369,217	53,939	119,737	199,435	3,278	28,309	-	-	-	665	2,712,000
13		Sep-21		1,338,112	50,482	540,116	337,683	45,583	124,320	200,447	400	28,344	-	-	-	514	2,666,000
14																	
15	Non-Coincident Peak (kW)																
16		Oct-20		1,123,748	57,803	463,246	364,645	52,388	133,859	196,206	3,326	29,165	11,804	2,673	428	3,777	2,443,069
17		Nov-20		736,605	46,982	383,720	331,668	43,898	122,740	189,229	3,527	27,819	10,892	2,360	377	3,532	1,903,349
18		Dec-20		830,995	62,339	447,999	348,495	47,323	119,216	185,954	26,093	26,986	12,101	2,431	391	2,935	2,113,258
19		Jan-21		999,703	66,660	448,098	316,846	39,280	114,703	189,592	4,166	27,281	11,257	2,263	363	2,715	2,222,927
20		Feb-21		1,329,880	91,080	494,967	360,887	44,853	115,067	185,147	4,577	27,197	13,417	3,353	538	3,974	2,674,939
21		Mar-21		708,379	46,122	345,304	281,539	31,858	119,252	189,259	3,924	27,067	9,869	2,421	390	4,135	1,769,517
22		Apr-21		986,575	43,288	452,050	346,730	47,343	128,492	192,203	2,528	28,094	11,223	3,118	502	4,192	2,246,338
23		May-21		1,144,819	52,792	521,093	387,146	51,677	135,189	196,133	20,164	29,339	13,053	3,703	598	3,990	2,559,695
24		Jun-21		1,333,629	59,355	601,309	418,797	62,410	142,193	201,273	42,050	29,562	13,093	3,988	643	3,218	2,911,521
25		Jul-21		1,353,120	56,766	600,318	396,094	54,018	141,294	200,670	3,404	29,284	11,082	3,351	542	2,250	2,852,193
26		Aug-21		1,357,388	62,473	609,112	409,490	58,403	144,268	202,417	40,615	29,325	11,318	3,235	522	3,655	2,932,222
27		Sep-21		1,400,053	56,304	579,153	368,946	50,944	144,704	201,933	42,490	29,081	9,602	2,453	398	4,058	2,890,121
28																	
29	Coincident Peak @ ERCOT Peak (kW)																
30		Oct-20		1,104,323	35,556	396,481	297,057	44,797	114,264	194,637	3,231	28,244	-	-	-	409	2,219,000
31		Nov-20		355,031	25,941	292,929	296,626	39,612	119,638	184,982	2,897	26,784	139	30	5	386	1,345,000
32		Dec-20		731,981	60,230	433,336	342,558	45,572	111,063	176,979	2,653	25,052	4,544	913	147	972	1,936,000
33		Jan-21		895,141	66,660	448,098	316,846	37,562	106,547	178,913	2,432	25,394	5,378	1,081	174	774	2,085,000
34		Feb-21		954,628	63,307	426,871	299,355	35,452	103,474	174,338	2,431	24,189	1,906	476	76	497	2,087,000
35		Mar-21		654,028	26,877	282,341	225,311	29,350	108,298	187,145	2,320	27,022	-	-	-	307	1,543,000
36		Apr-21		926,916	39,365	428,970	327,092	43,310	116,971	189,905	68	27,694	-	-	-	710	2,101,000
37		May-21		997,991	46,811	501,452	358,409	46,911	116,128	192,791	2,482	28,508	-	-	-	518	2,292,000
38		Jun-21		1,248,355	51,869	548,489	374,058	54,935	122,642	199,614	3,274	29,217	-	-	-	549	2,633,000
39		Jul-21		1,247,231	56,766	578,849	375,582	51,380	119,289	197,559	3,301	28,510	-	-	-	533	2,659,000
40		Aug-21		1,213,364	59,821	584,090	382,719	53,143	121,229	199,352	3,373	28,269	-	-	-	640	2,646,000
41		Sep-21		1,162,367	53,643	578,801	354,798	50,773	138,007	201,140	25,332	28,631	-	-	-	509	2,594,000
42																	
43	Coincident Peak @ ERCOT Peak																
44		Jun-21		1,248,355	51,869	548,489	374,058	54,935	122,642	199,614	3,274	29,217	-	-	-	549	2,633,000
45		Jul-21		1,247,231	56,766	578,849	375,582	51,380	119,289	197,559	3,301	28,510	-	-	-	533	2,659,000
46		Aug-21		1,213,364	59,821	584,090	382,719	53,143	121,229	199,352	3,373	28,269	-	-	-	640	2,646,000
47		Sep-21		1,162,367	53,643	578,801	354,798	50,773	138,007	201,140	25,332	28,631	-	-	-	509	2,594,000
48																	
49	Energy @ Gen (kWh)																
50		Oct-20		395,363,547	24,597,611	225,566,776	203,253,681	29,903,261	87,300,451	138,106,850	2,113,024	20,036,201	4,096,554	927,735	148,526	473,783	1,131,888,000
51		Nov-20		307,610,179	21,838,614	188,251,772	182,923,010	25,552,878	80,764,687	130,942,290	2,169,961	19,072,493	4,127,377	894,337	142,859	420,543	964,711,000
52		Dec-20		356,923,631	25,518,724	210,604,673	195,812,130	28,834,787	80,511,558	132,665,751	1,910,197	18,898,867	4,904,689	985,437	158,377	401,178	1,058,130,000
53		Jan-21		393,456,234	27,112,008	211,700,331	184,976,947	23,905,827	78,960,689	133,465,363	1,741,865	18,954,996	4,498,384	904,358	145,257	393,740	1,080,216,000
54		Feb-21		374,602,056	26,036,135	201,468,499	168,364,643	21,937,188	68,329,606	82,994,215	1,548,272	14,105,633	3,811,461	952,567	152,709	424,016	964,727,000
55		Mar-21		313,839,961	22,649,806	179,470,763	155,651,223	19,269,639	81,043,134	128,290,383	1,661,998	18,579,927	3,457,336	848,236	136,515	430,081	925,329,000
56		Apr-21		338,479,070	23,288,020	215,316,094	189,347,870	27,283,730	81,716,136	130,321,976	1,256,368	18,946,805	3,540,947	983,868	158,484	417,631	1,031,057,000
57		May-21		398,963,379	27,208,800	254,391,570	212,854,853	31,019,860	87,757,428	138,855,371	1,738,896	20,043,589	3,454,555	1,086,227	175,489	405,983	1,177,956,000
58		Jun-21		539,066,883	29,900,849	289,207,143	223,075,966	36,689,920	92,261,428	138,887,309	6,484,712	20,323,070	3,239,929	1,117,155	180,250	428,383	1,380,863,000
59		Jul-21		581,445,757	29,947,617	303,217,673	224,100,100	33,676,213	95,622,253	145,573,366	2,237,764	20,999,691	2,958,044	985,386	159,404	389,733	1,441,313,000
60		Aug-21		605,805,538	32,683,011	317,247,902	234,818,862	36,231,559	97,530,997	147,450,783	2,210,239	21,060,289	3,461,639	1,030,213	166,226	500,741	1,500,198,000
61		Sep-21		543,864,116	27,476,289	271,690,407	196,074,647	29,473,201	91,655,383	139,089,494	2,297,627	19,673,519	3,212,188	820,548	133,256	487,327	1,325,948,000
62																	
63	Retail Energy @ Meter (kWh)																
64		Oct-20		375,026,046	23,332,310	213,963,621	192,798,312	29,170,033	85,159,844	134,720,470	2,087,119	19,790,557	3,885,827	880,012	140,886	449,411	1,081,404,448
65		Nov-20		291,786,712	20,715,235	178,568,101	173,513,451	24,926,321	78,784,337	127,731,585	2,143,357	18,838,664	3,915,065	848,333	135,510	398,910	922,305,581
66		Dec-20		338,563,479	24,206,041	199,771,169	185,739,554	28,127,758	78,537,414	129,412,787	1,886,778	18,667,167	4,652,392	934,746	150,230	380,542	1,011,030,058
67		Jan-21		373,216,846	25,717,367	200,810,466	175,461,733	23,319,656	77,024,573	130,192,792	1,720,510	18,722,608	4,266,987	857,838	137,785	373,486	1,031,822,646
68		Feb-21		355,332,526	24,696,836	191,104,959	159,703,966	21,399,288	66,654,164	80,959,197	1,529,291	13,932,698	3,615,399	903,567	144,853	402,205	920,378,950
69		Mar-21		297,696,033	21,484,700	170,238,787	147,644,524	18,797,147	79,055,956	125,144,703	1,641,622	18,352,137	3,279,490	804,603	129,492	407,958	884,677,152
70		Apr-21		321,067,706	22,090,084	204,240,235	179,607,815	26,614,733	79,712,456	127,126,481	1,240,965	18,714,518	3,358,801	933,258	150,331	396,148	985,253,532
71		May-21		378,440,703	25,809,180	241,305,667	201,905,599	30,259,254	85,605,616	135,450,637	1,717,577	19,797,854	3,276,853	1,030,351	166,462	385,099	1,125,150,852
72		Jun-21		511,337,283	28,362,749	274,330,328	211,600,939	35,790,283	89,999,178	135,481,793	6,405,209	20,073,909	3,073,267	1,059,689	170,978	406,347	1,318,091,953
73		Jul-21		551,536,188	28,407,112	287,620,156	212,572,391	32,850,472	93,277,595	142,003,907	2,210,329	20,742,235	2,805,882	934,697	151,204	369,685	1,375,481,852
74		Aug-21		574,642,901	31,001,797	300,928,670	222,739,780	35,343,161	95,139,537	143,835,290	2,183,142	20,802,090	3,283,572	977,219	157,676	474,983	1,431,509,817
75		Sep-21		515,887,746	26,062,909	257,714,653	185,988,567	28,750,519	89,407,993	135,679,019	2,269,458	19,432,321	3,046,953	778,339	126,401	462,259	1,265,607,135
76																	
77	Sum of Maximum Demands (kW-months)																
78		Oct-20		2,661,532	99,994	720,068	429,712	60,208	146,118	192,007	3,322	28,808	10,096	2,242	359	4,880	4,359,345
79		Nov-20		2,169,239	96,893	624,170	388,303	52,424	134,321	185,458	3,550	27,515	9,761	2,090	334	4,309	3,698,366
80		Dec-20		2,332,593	115,653	674,065	400,228	57,496	128,461	182,281	26,229	26,655	10,770	2,159	347	4,175	3,961,112

TIEC 1-3: Provide a schedule showing AE's monthly system peak demand for calendar years 2017 through 2021 and as projected for calendar years 2022 through 2026.

ANSWER: See attachment.

Attachment TIEC 1-3a: Austin Energy's monthly system hourly peak demand for calendar year 2017 through 2021

Austin Energy filed an objection on May 26, 2022 to the portion of TIEC 1-3 relating to Austin Energy's projected system hourly peak demand for calendar year 2022 through 2026.

Prepared by: ZD and JL

Sponsored by: Brian Murphy

Month	Demand
Jan-2017	2118
Feb-2017	1665
Mar-2017	1894
Apr-2017	2186
May-2017	2173
Jun-2017	2654
Jul-2017	2620
Aug-2017	2624
Sep-2017	2451
Oct-2017	2322
Nov-2017	1961
Dec-2017	2009
Jan-2018	2381
Feb-2018	2021
Mar-2018	1825
Apr-2018	1857
May-2018	2532
Jun-2018	2563
Jul-2018	2878
Aug-2018	2744
Sep-2018	2411
Oct-2018	2220
Nov-2018	2023
Dec-2018	1883
Jan-2019	1983
Feb-2019	1984
Mar-2019	2156
Apr-2019	1961
May-2019	2276
Jun-2019	2592
Jul-2019	2700
Aug-2019	2810
Sep-2019	2636
Oct-2019	2427
Nov-2019	2060
Dec-2019	1969
Jan-2020	1698
Feb-2020	2031
Mar-2020	1880
Apr-2020	2085
May-2020	2370
Jun-2020	2556
Jul-2020	2731
Aug-2020	2810
Sep-2020	2607
Oct-2020	2192

Nov-2020	1730
Dec-2020	1890
Jan-2021	2018
Feb-2021	2580
Mar-2021	1634
Apr-2021	2047
May-2021	2273
Jun-2021	2620
Jul-2021	2593
Aug-2021	2644
Sep-2021	2644
Oct-2021	2194
Nov-2021	1712
Dec-2021	1785

ORDINANCE NO. 20120607-055

AN ORDINANCE PRESCRIBING AND LEVYING RATES AND CHARGES FOR SALES MADE AND SERVICES RENDERED IN CONNECTION WITH THE ELECTRIC LIGHT AND POWER SYSTEM OF THE CITY OF AUSTIN FOR RESIDENTIAL, COMMERCIAL, PUBLIC, AND OTHER USES OF ELECTRIC LIGHT AND POWER SOLD AND SERVED BY THE CITY OF AUSTIN.

BE IT ORDAINED BY THE CITY COUNCIL OF THE CITY OF AUSTIN:

PART 1. The monthly rates and charges for sales made and services rendered by any part of the electric light and power works and system of the City of Austin are hereby established, levied, fixed, and prescribed pursuant to the retail rate schedules attached hereto as Exhibit A and incorporated by reference.

PART 2. Service rendered under these retail rate schedules shall be provided pursuant to City Code Section 15-9, Utility Service Regulations, and the Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin.

PART 3. These retail rate schedules have been adopted after a complete investigation of facts and policies bearing upon them, including formation of a Public Involvement Committee, five hearings before the Electric Utility Commission, twelve Council work session meetings, and three public hearings before the Council. Based on such investigation and hearings, the City Council finds and determines that these rates and charges are fair, just, and reasonable; are equal, uniform, and nondiscriminatory; are necessary to meet the operating and maintenance expenses and provide for depreciation and replacement of assets of the electric system, to provide for reasonable extensions and additions thereto in order to render efficient service, and to pay principal and interest on revenue bonds; and are sufficient to provide only a reasonable and proper return on the fair value of the electric system's properties dedicated to the furnishing of electric service.

PART 4. The Council further finds that the 2009 test year data, adjusted for known and measurable changes, support an annual utility revenue requirement of $1,123,477,268 under current City financial and reserve policies. To mitigate the magnitude of rate increase required to achieve this requirement, the Council adopts these retail rate schedules to achieve annual revenues of $1,089,529,780. It is the intent of the City Council to move toward full recovery of utility revenue requirements through the further examination of reserve policies, prudent cost reduction measures, and allocations of off-system sales net revenues, the implementation of revised retail rate schedules by October 1, 2014 (to the extent then supported by most recent available test year data), and the automatic expiration of all existing fixed-rate service contracts pursuant to their terms on May 31, 2015.

PART 5. These retail rate schedules reflect a consolidation of customer classes and a move toward rates based upon cost-of-service but adjusted to mitigate rate shock and support the community priorities of energy efficiency, peak demand reduction, and assistance to low-income customers.

PART 6. The Council adopts as policy the use of the A&E 4CP methodology to allocate production demand costs among customer rate classes.

PART 7. The Council adopts a policy of targeting a debt-to-equity ratio of 60/40 for financing electric utility capital projects until October 1, 2014, and reaffirms the current long-term policy of maintaining a 50/50 ratio.

PART 8. The Council finds that a tiered residential rate structure promotes energy efficiency and peak demand reduction.

PART 9. The Council finds that a discount for Independent School Districts and a rate cap for group worship facilities currently receiving residential service are fair, just, and reasonable, and support the community priorities of well-funded public education and avoidance of unplanned-for budget impacts.

PART 10. The Council finds that rising utility rates affect low-income residential households and that it is necessary and reasonable to provide discounted rates, targeted energy efficiency programs, and bill payment assistance for residential customers with an inability to pay due to poverty. To mitigate the effect of the rate increase on low-income residential households, the Council establishes a Customer Assistance Program as set forth in the Community Benefit Charge Rate Schedule.

PART 11. The retail rate schedules established herein shall be effective on all bills rendered on or after October 1, 2012, at which time all other ordinances, resolutions, or orders in conflict with this ordinance are repealed. The rate schedules set forth in Ordinance No. 20110912-007, as amended by Ordinances Nos. 20111208-133 and 20120524-141, shall continue in full force and effect on all bills rendered before October 1, 2012.

PART 12. The Council adopts as policy that Austin Energy's rates should be reviewed at least once every five years. The Council will establish a process for rate policy development and decision making that will ensure that all customer classes have an opportunity to participate and that their interests are considered. As part of this process, the City will hire a consumer advocate who is knowledgeable and experienced in ratemaking issues to represent residential and small business customers. The City may also hire an impartial hearing examiner to conduct the review and make recommendations.

PART 13. This ordinance takes effect on June 18, 2012.

PASSED AND APPROVED

June 7, 2012 § § § Lee Leffingwell
Mayor

APPROVED: Karen M. Kennard
City Attorney

ATTEST: Shirley A. Gentry
City Clerk

AUSTIN ENERGY'S	§	**BEFORE THE CITY OF AUSTIN**
2022 BASE RATE REVIEW	§	
	§	**IMPARTIAL HEARING EXAMINER**

AUSTIN ENERGY'S SUPPLEMENTAL RESPONSE TO NXP SEMICONDUCTORS' THIRD REQUEST FOR INFORMATION

Austin Energy files this Supplemental Response to NXP Semiconductors' ("NXP") Third Request for Information ("RFI") submitted on May 26, 2022.

Respectfully submitted,

LLOYD GOSSELINK ROCHELLE & TOWNSEND, P.C.
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ATTORNEYS FOR THE CITY OF AUSTIN D/B/A AUSTIN ENERGY

NXP 3-11: Please provide a copy of AE's distribution system planning manuals, guidelines, instructions, criteria, and other similar documents.

<u>ANSWER:</u> See Attachment NXP 3-11.

Prepared by: JL

Sponsored by: Thomas Pierpoint

AUSTIN ENERGY

DISTRIBUTION PLANNING CRITERIA

Prepared by

Planning and Regulatory Engineering

TABLE OF CONTENTS

Exceptions to the Planning Criteria

1.01. Planning Criteria as Guidelines

The Planning Criteria are intended to be guidelines. Exceptions to the Planning Criteria may be approved in appropriate circumstances.

1.02. Minor Violations

Some Planning Criteria violations are minor, and eliminating the violation may not provide a cost-effective solution.

1.03. Temporary Conditions

Occasionally, operation in violation of the Planning Criteria is necessary because of unexpected events, such as long-term forced outages of equipment, unforeseen load changes, and delays in project completion. If a Planning Criteria violation will exist for a short period of time only, *i.e.*, one to two years, it may be possible to delay construction with operational solutions.

General Provisions

2.01. Objectives of the Planning Criteria

a) The Distribution System Planning Criteria provide the guidelines followed by Austin Energy to provide a cost-effective and reliable plan for accommodating the changes in distribution system load.

b) The Planning Criteria will be applied in distribution capacity planning studies to identify problem areas, plan new facilities, and recommend distribution system improvements or retirements.

2.02. Review and Revisions to the Planning Criteria

a) Austin Energy personnel will review the Planning Criteria periodically (approximately every three (3) years) and recommend revisions as necessary.

b) Revisions to the Planning Criteria require the approval of the Senior Vice President of Electric Service Delivery.

2.03. System Conditions

a) Distribution capacity studies assume summer peak conditions to determine substation peak loading. Weather adjusted summer peak loads are used when appropriate.

b) Winter peak and seasonal minimum conditions are considered when such conditions constitute a significant reliability threat for distribution system loads.

2.04 Contingency Levels

a) "Normal" means the steady state condition of the distribution system with all facilities in service and all loads being served.

b) "Level A contingency," means the steady-state condition of the distribution system following the outage of any single distribution circuit. Level A contingency conditions are preceded by Normal conditions.

c) "Level B contingency" means the steady-state condition of the distribution system following an outage caused by a single event resulting in the loss of any:

1) overhead double-circuited distribution line,
2) distribution substation switch-gear,
3) distribution substation transformer,

Level B contingency conditions are preceded by Normal conditions.

d) "Level C contingency" means the steady-state condition of the distribution system following a common mode failure of an entire distribution substation or a duct bank that results in the loss of more than three distribution circuits.

2.05. Facility Ratings

The loading on all distribution facilities and distribution substation facilities should be reduced to or below the normal equipment ratings within twenty-four hours to limit loss of equipment life and to prevent additional contingencies.

The methodology and assumptions used for setting normal and emergency ratings for distribution and substation facilities are described in the appendices.

2.06. SCADA Limits

Distribution Planning shall have the responsibility for assigning the SCADA alarm settings for each circuit. These settings will be reviewed annually and adjusted as needed.

The purpose of the SCADA alarm system is to allow operators sufficient warning to minimize overloads on the distribution system. The SCADA alarm settings may be adjusted as necessary to allow for practical operational considerations and flexibility. Such adjustments shall not impair reliable service to customer loads.

The first alarm limit, LIM1, shall generally be the normal rating of the feeder get-a-way cables. The second alarm limit, LIM2, shall generally be 50 amps less than the emergency rating of the feeder get-a-way cables.

When the overhead conductor is the limiting factor, the first SCADA limit, LIM1, shall be 100A less than the (75° C) rating of the overhead conductor. The second SCADA limit, LIM2 shall be 50A less than the (75° C) rating of the overhead conductor.

Planning Criteria for Distribution Circuits

3.01. Maximum Loading on Distribution Facilities

a) Under Normal conditions, no distribution facility shall be loaded greater than its normal rating.

b) Under contingency conditions following service restoration switching, no distribution facility shall be loaded greater than its emergency rating.

c) Steady state loading on all distribution facilities should be reduced to or below the normal rating within twenty-four hours for contingency levels A and B.

d) Service shall be restored to all outaged distribution facilities following:

1) normal automatic operation of protective equipment, or

2) manual switching within twenty-four hours, or

3) placement and connection of the mobile substation transformer within twenty-four hours.

3.02. Maximum Voltage Drop on Distribution Circuits

a) The maximum voltage drop shall not exceed 6 V (5%) on a 120 V base under Normal conditions.

b) The maximum voltage drop shall not exceed 10 V (8%) on a 120 V base under all contingency conditions following service restoration switching.

3.03. Service Restoration Switching

a) Switching to restore service to non-faulted circuits or sections following a Level A contingency should require no more than two hours.

b) Switching to restore service to non-faulted circuits or sections following a Level B contingency should require no more than twenty-four hours.

c) Switching to restore service to non-faulted circuits or sections following a Level C contingency could take in excess of twenty-four hours.

NOTE: This section does not apply if AE's distribution system is subject to a "Major Event" as defined by Texas Public Utility Commission's Reliability and Continuity of Service Rule 25.52

3.04. Power Factor on Overhead Distribution Circuits

a) The power factor on an overhead distribution circuit shall be as close to unity as practicable at summer peak load; and,

b) The combined power factor of all overhead distribution circuits connected to the same substation transformer bus should not be below 97% lagging.

3.05. Service to Large Distribution Customers

Customers with loads in excess of 4,000 kVA (185 A) at 12 kV should be requested to split their loads into approximately equal parts between two feeds if practicable.

3.06. Installation of New Pole-Top Switches

A new pole-top switch shall be considered when four or more pole-top switches must be operated to isolate a section under Level A contingency conditions.

Planning Criteria for Automatic Load Transfers

4.01. Automatic Load Transfer Placement

The routing of multiple feeds to an automatic load transfer service must be such that the distribution dispatcher can make full use of associated distribution circuits for normal and emergency service.

4.02. De-rating of Facilities

Facilities used to provide automatic load transfer service to customers should be de-rated as follows:

a) The load on the circuit providing the alternate feed to an automatic load transfer service should be limited to the emergency rating minus the anticipated maximum demand of the automatic load transfer.

b) The load on the substation transformer serving the alternate feed to the automatic load transfer should be limited to the emergency rating minus the anticipated maximum demand of the automatic load transfer.

c) Planned load transfer will be limited to the maximum contracted reserve capacity (anticipated maximum demand).

4.03. Limitations of Automatic Load Transfers

Transfer from the backup circuit back to the primary circuit shall be manual and coordinated through the Energy Control Center.

Planning Criteria for Distribution Substations

5.01. Transmission System Connection Criteria

a) After the outage of any single transmission facility that serves a distribution substation facility, service shall be restored to all distribution facilities that are served by the substation facility following either:

1) normal automatic operation of protective equipment; or
2) manual switching that does not exceed two hours.

b) Distribution substation connections to transmission sources shall preclude a single transmission line outage, followed by normal automatic sectionalizing and switching, from outaging both the primary substation transformer and its alternate.

5.02. Maximum Loading on Substation Transformers

a) Under Normal conditions, no substation transformer shall be loaded to greater than its normal rating (100 % full load or 95 degree Celsius top oil temperature).

d) Under a Level B contingency, no substation transformer shall be loaded to greater than its twenty-four hour emergency rating (107% of full load or 110 degree Celsius top oil temperature).

e) Under a Level C contingency, no substation transformer shall be loaded greater than its twenty-four hour emergency rating, 107% of full load. However, the transformer may be loaded at this level in excess of twenty-four hours.

Note: For Austin Energy's typical 30 MVA substation transformer, the normal rating would be 1,400 amps full load or 95 degree Celsius top oil temperature. Its twenty four hour emergency rating would be 1,500 amps or 110 degree Celsius top oil temperature.

Definitions

a) Automatic transfer service is the extension of two or more separate distribution feeders to the customer's site and the installation of load transfer equipment such that when the primary source of power is interrupted, the load is transferred to the secondary source of power.

b) "Distribution facility" means any Austin Energy equipment used to distribute electric energy to the public at a nominal line-to-line voltage of 34.5 (35) kV or below, excluding distribution substation facilities.

c) "Distribution substation facility" means a facility used to connect distribution facilities to a transmission (138KV, or 69KV) source. This includes all equipment and facilities between the high side bus of the power transformer through the low side switchgear.

d) "Protective equipment" means breakers, relays, or sectionalizing switches.

e) "Section" means a portion of a distribution circuit that is bounded by switching devices.

f) "Switching devices" means switches or breakers.

g) "Transmission facility" means any facility used to transmit electrical energy to a substation facility at a nominal line-to-line voltage of 69 kV or greater, excluding substation facilities.

h) **Major events** — Interruptions that result from a catastrophic event that exceeds the design limits of the electric power system, such as an earthquake or an extreme storm. These events shall include situations where there is a loss of power to 10% or more of the customers in a region over a 24-hour period and with all customers not restored within 24 hours. *(Texas Public Utility Commission's Reliability and Continuity of Service Rule 25.52)*

APPENDIX

Appendix A --- Distribution Planning Criteria

Distribution Planning Criteria

System Condition	Maximum Facility Loading	Maximum Voltage Drop	Restoration Time (Non-Faulted Sections)
Normal	Normal Equipment Ratings	6 Volts (5%) on a 120 volt basis	N/A
Level A	Emergency Equipment Ratings	10 Volts (8%) on a 120 volt basis	Two Hours
Level B	Emergency Equipment Ratings	10 Volts (8%) on a 120 volt basis	Twenty-four Hours
Level C	Emergency Equipment Ratings	10 Volts (8%) on a 120 volt basis	Exceeds Twenty-four Hours

(Meets with ANCI C84.1 1989 , red book page 69-70)

a) “Normal” means the steady state condition of the distribution system with all facilities in service and all loads being served.

b) “Level A contingency,” means the steady-state condition of the distribution system following the outage of any single distribution circuit. Level A contingency conditions are preceded by Normal conditions.

c) “Level B contingency” means the steady-state condition of the distribution system following an outage caused by a single event resulting in the loss of any:

1. overhead double-circuited distribution line,
2. distribution substation switch-gear,
3. distribution substation transformer,

d) Level B contingency conditions are preceded by Normal conditions.

e) “Level C contingency” means the steady-state condition of the distribution system following a common mode failure of an entire distribution substation or a duct bank that results in the loss of more than three distribution circuits.

Appendix B --- Distribution Substation Loading Limits

Normal limit = 95 degrees Celsius

Emergency limit = 110 degrees Celsius

Example:

30MVA Transformer
Rated for 65 degree Celsius temperature rise above ambient
Assume ambient = 30 degrees Celsius (C) (86 degrees Fahrenheit)

V = 12.47kV

Therefore:

I full load = 30Mva/(sqrt(3)*12.47kV)
I full load = 1389 amps (approx. 1400 amps)

Assumming that a 65 degree Celsius temperature rise occurs at full load

Then:

A temperature vs. current characteristic curve can be derived which is shifted up or down depending on the ambient temperature.

TCC = 1389 amps/65C = 21.37 amps/C

Therefore:

For Normal = 95C max. limit @ ambient = 30C,
I full load = 1389 amps (approx. 1400 amps)

The emergency = 110C @40C ambient
I full load =(21.37amps/C)(110C-40C) = 1495.9 (approx. 1500)amps

Appendix C --- Circuit Get-A-Way Ampacity Limits

The allowable ampacity for individual underground circuit get-a-ways shall be determined by the following factors:

- Cable size and composition.
- The maximum number of circuits in a common duct bank.
- The number, size, and arrangement of conduits in the common duct bank.
- The configuration of the cables in the common duct bank.
- The load profile served by each circuit.
- The seasonal timing of the maximum circuit demand.

The load profile will generally fall into one of four categories:

Urban – High density, mixed commercial and residential.
Suburban – Lower density, mixed commercial and residential.
Network – Underground network system serving the Central Business District.
Industrial – Large industrial or commercial customers with a high load factor.

The maximum demand for most circuits will occur during periods of extreme heat, when air conditioning usage is at a peak (summer peaking circuits). The maximum demand on some circuits may occur during periods of extreme cold, due to high concentrations of residential and commercial customers with electric heating (winter peaking circuits). The AE system as a whole usually sees two system peaks, a summer peak in the July-August time frame, and a winter peak in the December-January time frame.

The load profiles for summer and winter seasonal peaks may be significantly different, depending on the type of load served. Generally, using the winter load profile will result in more conservative circuit ratings, as the winter curve is flatter, permitting the cable less time to cool. To insure that the cable ratings assigned to system circuits are somewhat conservative, ratings analysis should use the following guidelines:

Type	Load Curve
Urban	Winter*
Suburban	Summer
Network	Winter
Industrial	Winter

* - The summer load curve may be used for urban circuits where the summer peak exceeds the winter peak by 25% or more.

For the purposes of assigning ratings, it is assumed that all of the circuits in the common duct bank are equally loaded. This is rarely the case in reality, but this assumption provides an additional safety margin in the calculations. The load profiles for circuits at or above 85% of their rated capacity should be reviewed on an annual basis, to determine if changes in circuit configuration or customer loads have affected the circuit ratings.

Normal Ratings: During normal conditions, underground circuit get-a-ways shall be limited to a normal operating temperature of 90^0 C (105^0 C for 105^0 C cable).

Emergency Ratings: During emergency conditions, substation feeder cables may be allowed to operate at a 130° C temperature (140° C temperature for 105^0 C cable) with the assumption that only one feeder per duct bank may attain this limit. Emergency ratings may be assigned using the same load profiles as the normal rating, with exceptions for circuits that normally serve urban or suburban loads that may pick up industrial loads during emergency conditions.

Calculating the Ratings: The ratings are calculated by Distribution Planning using the program "ETAP". Unless specific data is known, the following assumptions are made:

1) All conduits 5-inch, PVC schedule 40 with 2 inch spacing (from edges).
2) 25^o C ambient temperature.
3) Soil Rho of 90.[1]
4) Fill Rho of 44.[1]
5) Average dry soil
6) Heavy aggregate fill
7) Burial depth of thirty six inches to top of duct bank[2]
8) All cables BICC Unishield power cable, 133% insulation, 15 kV.
9) All circuits equally loaded.

[1] *Typical values of Thermal Resistivity as per Appendix B 1996 NEC Handbook*
[2] *Assumed depth unless duct bank profiles available.*

Conservative Ratings: In situations where a quick conservative cable rating is needed, the table on the next page is taken from the Duke Engineering and Services study "Cable Rating Study" dated January 1998. Please note the assumptions following the table.

Nine-Way Duct Bank One Circuit Per Conduit[A]

# Circuits in Bank	500 MCM Normal	500 MCM Emergency	1000 MCM Normal	1000 MCM Emergency
1	540	653	790	956
2	500	620	720	900
3	450	581	640	838
4	420	563	590	808
5	400	544	560	784
6	380	536	540	767
7	370	525	520	754
8	350	522	500	740

[A] Taken from DE&S "Cable Rating Study" dated January 1998

1) All conduits 5-inch, PVC schedule 40 with 2 inch spacing (from edges).
2) 20^{o} C ambient tempature.
3) Soil and fill Rhos of 90.
4) Average dry soil
5) Heavy aggregate fill
6) Burial depth of two feet to top of duct bank
7) All cables BICC Unishield power cable, 133% insulation, 15 kV.
8) All circuits equally loaded.
9) All circuits utilize winter urban load curve
10) Normal ratings based on conductor temperature of 90^{o} C.
11) Emergency ratings based on conductor temperature of 130^{0} C.

Appendix D --- Overhead Conductor Loading Limits

Table 6.1.1 Types of Overhead Wires and Conductors

Conductor Size and Stranding (AWG, kcmil or inch)	Type	Code Word	Austin Energy Stock Number	Ampacity ~1	Overall Diameter (inch)	Weight (lb/ft)	Ultimate Breaking Strength (lb)
Bare All Aluminum Overhead Conductor							
4/0, 7~4	AAC	OXLIP	0000000851	380	0.5220	0.1987	3,830.00
795, 37~2	AAC	ARBUTUS	0000004530	900	1.0260	0.7464	13,900.00
Bare ACSR Aluminum Overhead Conductor							
1/0, 6/1~4	ACSR	RAVEN	0000004537	230	0.3980	0.1453	4,380.00
4/0, 6/1	ACSR	PENGUIN	0000004538	340	0.5630	0.2911	8,350.00
336, 26/7	ACSR	LINNET	0000004540	530	0.7200	0.4625	14,100.00
795, 26/7	ACSR	DRAKE	0000004539	900	1.1080	1.0940	31,500.00
Bare Copper and Copperweld Conductor							
# 6, 1	Solid MHD Bare		0000004523	120	0.1620	0.0795	1,010.00
# 6, 1	Solid SD Bare		0000004527	120	0.1620	0.0795	762.90
# 4, 1	Solid MHD Bare		0000004522	170	0.2043	0.1264	1,584.00
# 2, 7	Stranded SD Bare		0000004533	230	0.2920	0.2049	2,007.00
# 2, 1	Solid MHD Bare		0000004521	220	0.2576	0.2009	2,450.00
1/0, 19	Stranded MHD Bare		0000004524	310	0.3730	0.3257	3,803.00
2/0, 19	Stranded SD Bare		0000001211	360	0.4190	0.4109	4,025.00
4/0, 19	Stranded MHD Bare		0000004525	480	0.5280	0.6533	7,479.00
2A	Copperweld		0000000710	240	0.3660	0.2568	5,876.00
6A	Copperweld		0000004529	140	0.2300	0.1016	2,585.00

The ampacity is based on a conductor temperature of 75.0 deg. C, 25.0 deg. C ambient temperature, 2 ft/sec cross wind, 0.5 Emissivity,

Line No.	Description	Total Company	Residential	Secondary Voltage < 10 kW	Secondary Voltage ≥ 10 < 300 kW	Secondary Voltage ≥ 300 kW	Primary Voltage < 3 MW	Primary Voltage ≥ 3 < 20 MW	Primary Voltage ≥ 20 MW @ 85% aLF	Transmission
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Power Production Expenses	$ 441,148,830	$ 181,105,254	$ 9,906,472	$ 89,318,490	$ 69,576,597	$ 10,003,393	$ 28,120,910	$ 44,008,407	$ 1,002,691
2	Transmission Expense	168,293,778	77,840,147	3,548,977	36,596,201	23,763,682	3,359,316	8,008,279	12,746,121	563,755
3	Distribution Expense	86,264,830	42,408,993	2,814,004	17,406,853	11,883,513	1,310,325	3,092,628	1,237,174	64,412
4	Customer and Information Expense	55,470,497	39,875,985	3,503,944	3,061,406	5,793,389	598,971	1,533,901	889,743	155,883
5	General and Administrative Expense	233,439,866	142,492,577	9,129,042	32,951,578	21,595,096	2,817,507	6,684,523	10,051,441	426,648
6	Total Operations and Maintenance Expense	984,617,801	483,722,956	28,902,440	179,334,527	132,612,278	18,089,512	47,440,242	68,932,887	2,213,388
7	Depreciation and Amortization of CIAC	146,765,700	73,865,676	3,976,386	29,036,369	19,097,385	2,243,027	5,239,307	8,006,780	232,018
8	Other Expenses	8,922,794	6,312,783	422,566	892,629	616,347	72,581	182,333	243,772	8,259
9	Cash Flow Return									
10	Debt Service	143,115,070	62,057,039	3,478,378	30,296,085	21,422,698	2,656,536	6,888,369	10,487,297	209,629
11	Non-Nuclear Decommissioning	8,000,000	3,943,945	157,642	1,603,734	1,070,395	153,122	356,308	584,341	25,086
12	General Fund Transfer	114,000,000	61,235,486	3,577,116	20,037,459	13,308,381	1,633,511	3,837,357	5,798,551	190,642
13	Internally-Generated Funds for Construction	96,960,744	46,781,467	2,760,070	19,692,677	12,955,351	1,394,117	3,273,014	4,805,953	101,102
14	Less: Depreciation Expense	(146,765,700)	(73,865,676)	(3,976,386)	(29,036,369)	(19,097,385)	(2,243,027)	(5,239,307)	(8,006,780)	(232,018)
15	Less: CIAC	(43,627,981)	(20,190,952)	(1,254,365)	(9,166,599)	(6,053,458)	(583,763)	(1,364,683)	(1,924,175)	(14,979)
16	Less: Interest and Dividend Income	(4,270,316)	(2,142,053)	(109,933)	(839,216)	(552,809)	(70,522)	(165,487)	(258,571)	(9,364)
17	Total Cash Flow Return	167,411,817	77,819,256	4,632,523	32,587,770	23,053,174	2,939,974	7,585,571	11,486,616	270,099
18	Less: Other Revenues	(136,368,862)	(65,483,457)	(3,130,316)	(28,720,601)	(18,639,994)	(2,569,900)	(6,115,681)	(9,679,549)	(415,958)
19	**TOTAL RETAIL ELECTRIC REVENUE REQUIREM**	**1,171,349,251**	**576,237,214**	**34,803,599**	**213,130,695**	**156,739,190**	**20,775,194**	**54,331,772**	**78,990,505**	**2,307,805**
20	Less: PSA Recovery	(329,232,528)	(121,249,889)	(7,493,792)	(67,533,986)	(55,834,299)	(8,094,708)	(24,098,567)	(37,359,604)	(644,484)
21	Less: Regulatory Recovery	(128,219,574)	(58,508,213)	(2,718,037)	(27,777,686)	(18,344,989)	(2,598,491)	(6,317,819)	(10,029,981)	(417,745)
22	Less: Community Benefit	(30,745,700)	(15,325,971)	(923,787)	(5,681,076)	(4,176,804)	(552,145)	(1,444,132)	(2,182,970)	(61,041)
23	**BASE RATE REVENUE REQUIREMENT**	**$ 683,151,448**	**$ 381,153,142**	**$ 23,667,983**	**$ 112,137,947**	**$ 78,383,098**	**$ 9,529,850**	**$ 22,471,254**	**$ 29,417,951**	**$ 1,184,535**

Exhibit NXP-JWD-6
Page 1 of 2

Line No.	Description	Transmission Voltage ≥ 20 MW @ 85% aLF	Service Area Street Lighting	City-Owned Private Outdoor Lighting	Customer-Owned Non-Metered Lighting	Customer-Owned Metered Lighting
	(a)	(k)	(l)	(m)	(n)	(o)
1	Power Production Expenses	$ 6,337,990	$ 1,159,283	$ 407,936	$ 51,324	$ 150,084
2	Transmission Expense	1,831,653	-	-	-	35,646
3	Distribution Expense	97,136	4,804,462	1,010,088	17,229	118,013
4	Customer and Information Expense	51,961	-	-	-	5,313
5	General and Administrative Expense	1,142,603	4,985,113	1,042,264	16,264	105,209
6	Total Operations and Maintenance Expense	9,461,343	10,948,858	2,460,288	84,818	414,265
7	Depreciation and Amortization of CIAC	752,822	3,458,995	733,151	16,911	106,873
8	Other Expenses	21,374	120,373	25,437	544	3,796
9	Cash Flow Return					
10	Debt Service	1,121,489	3,602,692	765,742	19,422	109,693
11	Non-Nuclear Decommissioning	84,102	15,074	3,885	625	1,742
12	General Fund Transfer	548,634	3,092,723	650,963	12,336	76,840
13	Internally-Generated Funds for Construction	289,247	3,962,218	832,360	14,161	99,008
14	Less: Depreciation Expense	(752,822)	(3,458,995)	(733,151)	(16,911)	(106,873)
15	Less: CIAC	(26,619)	(2,464,222)	(517,284)	(8,500)	(58,383)
16	Less: Interest and Dividend Income	(29,938)	(74,041)	(15,698)	(379)	(2,305)
17	Total Cash Flow Return	1,234,093	4,675,448	986,817	20,755	119,722
18	Less: Other Revenues	(1,345,102)	(186,408)	(41,126)	(1,944)	(38,827)
19	**TOTAL RETAIL ELECTRIC REVENUE REQUIREM**	**10,124,530**	**19,017,266**	**4,164,567**	**121,084**	**605,829**
20	Less: PSA Recovery	(5,432,020)	(1,054,006)	(271,632)	(43,734)	(121,808)
21	Less: Regulatory Recovery	(1,442,962)	(27,060)	(6,974)	(1,123)	(28,495)
22	Less: Community Benefit	(269,270)	-	(109,173)	(3,222)	(16,109)
23	**BASE RATE REVENUE REQUIREMENT**	**$ 2,980,278**	**$ 17,936,200**	**$ 3,776,789**	**$ 73,005**	**$ 439,417**

Exhibit NXP-JWD-6
Page 2 of 2

NXP's Proposed Revenue Distribution

Line No.	Rate Class	Current Base Rate Revenues (Excl. Street Lighting)	NXP Base Rate Cost of Service (Excl. Steet Lighting)	$ Increase at Cost of Service	% Increase at Cost of Service	Move Increase Classes 1/3 toward Cost of Service	Resulting Revenue (Surplus)/Deficiency	Revenue Requirement Distribution of Classes Above COS	Assigment of Surplus/(Deficiency)	Proposed Incr./(Decr.) - $	Proposed Incr./(Decr.) - %	Proposed Base Rate Revenue Distribution	Subsidy (Paid)/Received at Proposed Revenue Distribution - $
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	Residential	$ 298,139,951	$ 381,153,142	$ 83,013,191	27.8%	$ 27,671,064	$ 55,342,127	0.0%	$ -	$ 27,671,064	9.3%	$ 325,811,015	$ 55,342,127
2	Secondary Voltage < 10 kW	22,062,516	23,667,983	1,605,467	7.3%	535,156	1,070,311	0.0%	-	535,156	2.4%	22,597,672	1,070,311
3	Secondary Voltage ≥ 10 < 300 kW	146,379,682	112,137,947	(34,241,735)	-23.4%	-	(34,241,735)	45.7%	(1,214,192)	(1,214,192)	-0.8%	145,165,491	(33,027,543)
4	Secondary Voltage ≥ 300 kW	97,431,981	78,383,098	(19,048,883)	-19.6%	-	(19,048,883)	31.9%	(848,706)	(848,706)	-0.9%	96,583,276	(18,200,178)
5	Primary Voltage < 3 MW	8,571,888	9,529,850	957,962	11.2%	319,321	638,641	0.0%	-	319,321	3.7%	8,891,209	638,641
6	Primary Voltage ≥ 3 < 20 MW	24,590,380	22,471,254	(2,119,126)	-8.6%	-	(2,119,126)	9.2%	(243,311)	(243,311)	-1.0%	24,347,069	(1,875,815)
7	Primary Voltage ≥ 20 MW @ 85% aLF	33,906,126	29,417,951	(4,488,175)	-13.2%	-	(4,488,175)	12.0%	(318,528)	(318,528)	-0.9%	33,587,598	(4,169,647)
8	Transmission	801,058	1,184,535	383,478	47.9%	127,826	255,652	0.0%	-	127,826	16.0%	928,884	255,652
9	Transmission Voltage ≥ 20 MW @ 85% aLF	4,236,381	2,980,278	(1,256,103)	-29.7%	-	(1,256,103)	1.2%	(32,269)	(32,269)	-0.8%	4,204,112	(1,223,834)
10	Service Area Street Lighting	-	-	-	n/a	-	-	0.0%	-	-	n/a	-	-
11	City-Owned Private Outdoor Lighting	2,141,558	3,776,789	1,635,231	76.4%	545,077	1,090,154	0.0%	-	545,077	25.5%	2,686,635	1,090,154
12	Customer-Owned Non-Metered Lighting	45,878	73,005	27,127	59.1%	9,042	18,085	0.0%	-	9,042	19.7%	54,920	18,085
13	Customer-Owned Metered Lighting	316,344	439,417	123,072	38.9%	41,024	82,048	0.0%	-	41,024	13.0%	357,368	82,048
14	**Total***	**$ 638,623,744**	**$ 665,215,248**	**$ 26,591,505**	**4.2%**	**$ 29,248,510**	**$ (2,657,005)**	**100.0%**	**$ (2,657,005)**	**$ 26,591,505**	**4.2%**	**$ 665,215,248**	**$ -**

* Excludes $17,936,200 for Street Lighting

Charles E. Loy, CPA
Principal

EDUCATION: BBA Accounting, University of Texas at Austin
Certified Public Accountant, Texas

PROFESSIONAL MEMBERSHIPS:

American Water Works Association
National Association of Water Companies
Water Environment Federation
Texas Society of Certified Public Accountants
American Gas Association
American Public Gas Association
Texas Gas Association

EXPERIENCE:

Mr. Loy has over 25 years of experience helping organizations meet challenges arising in both regulated and competitive environments within in the utility industry.

2001-Present GDS Associates, Inc.: Principal – Mr. Loy started with GDS in June of 2001. His focus is on regulatory accounting and finance. He is experienced in natural gas, water, wastewater, and electric regulatory and accounting matters. Mr. Loy assisted a number of and gas distribution, gas transmission, water and electric clients with rate case filings before FERC and various regulatory authorities in a number of states. He has assisted with the financial analysis of wholesale purchase power and retail aggregation projects as a result of the deregulation of the electric industry in Texas. He has conducted analysis and developed recommendations regarding the Southwest Power Administration's rate increase on behalf of member clients. He has participated in a number of natural gas and electric projects involving rate increases, acquisition/merger analysis/assistance as well as other special projects.

1999-2001 AquaSource Inc.: General Manager Rates and Regulatory Affairs - AquaSource Inc., a wholly owned subsidiary of DQE Inc and parent of Duquesne Light. AquaSource was formed in 1997 to take advantage of the consolidation in the water and wastewater industries and spent three years and more than $400 million acquiring water and wastewater companies. Mr. Loy's duties included directing the compilation and filing of rate cases, acquisition analyses and related filings, regulatory commission/governmental relations in the twelve states in which AquaSource operates. Additionally, he supervised a professional staff located throughout the country and assisted in business development, developer contract negotiations and other special projects. His appointment came in the middle of AquaSource's aggressive acquisition phase. Accordingly, his first year was spent primarily working to clean up a very chaotic regulatory situation regarding acquisitions.

1993-1999 Citizens Utilities Company: Manager, Regulatory Affairs – Mr. Loy served as Project Manager of numerous multiple-company water and wastewater rate case filings, in Ohio, Illinois, Pennsylvania and Arizona. In those cases, he prepared and presented testimony, developed revenue requirement calculations, generated revenue and expense pro forma adjustments, performed working capital lead/lag studies, and evaluated rate design/cost of service issues. He proposed surcharge mechanisms for purchased water, a reverse osmosis process, and contract waste treatment. Additionally, Mr. Loy designed and directed the development of the multiple company revenue requirement models that generated filing schedules. In the fall of 1997, Citizens promoted Mr. Loy to Manager Regulatory Affairs. In the new position, he supervised the staff responsible for all regulatory activity involving gas, electric and water/wastewater in ten states. He was a key member of a team that negotiated a multimillion-dollar water and wastewater agreement with a major developer in Phoenix on behalf of Citizens. In addition, he assisted with the valuation, operational analysis and due diligence of utility acquisitions.

1989-1993 Southern Union Gas Company: Rate Manager – Mr. Loy joined Southern Union as Sr. Internal Auditor. In that capacity, he contributed to multiple projects pertaining to the upcoming merger with a large publicly traded corporation. These projects included supervising audits of gas purchases, accounts receivable, accounts payable and oil and gas holdings. He was promoted to Rate Manager reporting to the Vice President of Regulatory Affairs. In that capacity, he supervised a team of four directing the preparation and implementation of 16 rate increase applications before various municipal and state regulatory bodies, and led negotiating sessions with elected and municipal officials. In addition to improving efficiency, he developed several rate mechanisms that resulted in increased earnings. One such efficiency was the Weather Normalization Adjustment Clause (WNAC). By eliminating weather-sensitive fluctuations, the WNAC increased earnings as much as 12%. He also developed a Cost of Service Adjustment Clause (CSAC) which was established in several smaller municipal jurisdictions. The CSAC allowed annual rate increases without the time and expense of major rate filings. Also, Mr. Loy performed analysis and due diligence for numerous municipal and private acquisitions.

1987-1989 Diversified Utility Consultants, Inc.: Sr. Accounting Analyst - Diversified Utility Consultants (DUC) is a consulting firm which represents consumers' interests in rate case proceedings. The firm's clients include municipalities and various state-supported consumer agencies. As a Sr. Accounting Analyst, Mr. Loy worked on seven electric rate cases, two gas rate cases and one water rate case.

Prior to 1987 Mr. Loy spent summers in college rough necking, both offshore and onshore, on oil and gas drilling rigs. His first job after college was in the oil & gas industry where he started in accounts receivable and specialized in collecting past due accounts. He was in the Joint Interest Auditing Department where he reviewed drilling costs and negotiated refunds for the company and its joint interest owners.

Regulatory Experience:

Mr. Loy has presented testimony and/or participated in cases before the following regulatory bodies:

Pennsylvania Public Utility Commission – Water/Wastewater, Steam
Public Utilities Commission of Ohio – Water/Wastewater, Gas
Indiana Regulatory Commission – Water/Wastewater
Idaho Public Utilities Commission- Water
Illinois Commerce Commission – Water/Wastewater
Arizona Corporation Commission – Water/Wastewater, Conservation Rates, Reclaimed Water
Arkansas Public Utility Commission - Water
Oklahoma Corporation Commission – Gas
Hawaii Public Utilities Commission – Water/Wastewater
Texas Railroad Commission - Gas
Texas Public Utilities Commission – Electric, Water/Wastewater
Texas Commission on Environmental Quality – Water/Wastewater, Conservation Rates
Delaware Public Service Commission – Water, Conservation Rates
New Mexico Public Regulation Commission – Water/Wastewater, Conservation rates
New York Public Service Commission – Water
Public Service Commission of Montana - Gas
Public Service Commission of South Carolina – Water/Wastewater
Public Service Commission of West Virginia - Gas
Connecticut Department of Public Utility Control - Water
New Jersey Board of Public Utilities - Water
El Paso Public Utilities Board – Gas
Federal Energy Regulatory Commission -Gas

LIST OF TESTIMONY, EXPERT PROCEEDINGS, AND ENGAGEMENTS BY CHARLES E. LOY, CPA

GAS UTILITY RATES AND REGULATION EXPERIENCE

Railroad Commission of Texas

GUD Docket OS-20-00005136
Prepared cost of service and rate design and testimony of behalf of CoServ Gas, Ltd 2020 application, to increase rates in the incorporated and unincorporated areas it serves.

GUD Docket OS-20-00004865
Prepared consolidated filing and testimony of behalf of Universal Natural Gas, Inc., to Increase and Consolidate Rates in the Unincorporated Areas Served by Universal Natural Gas, LLC, d/b/a Universal Natural Gas, Inc. Consumers Gas Company, LLC d/b/a Consumers Gas Company Inc., Enertex NB, LLC, and Gas Energy, LLC

GUD Docket OS-20-00004866
Prepared consolidated filing and testimony of behalf of Hooks Gas Pipeline, LLC to Increase and Consolidate Rates for Hooks Gas Pipeline, LLC, Texas Gas Pipeline Company, LLC, and 1486 Gas Pipeline, LLC

GUD Docket 10988
Prepared filing and testimony of behalf of EPCOR Texas Gas 2020 rate increase for the environs of the City of Magnolia.

GUD Docket 10190
Prepared filing and testimony of behalf of Hughes Natural Gas 2012 rate increase for the environs of the City of Magnolia.

GUD Docket 10083
Prepared filing and testimony of behalf of Hughes Natural Gas 2011 rate increase for the incorporated area of the City of Magnolia and environs.

GUD Docket 9731
Prepared filing and testimony of behalf of Hughes Natural Gas 2007 rate increase for the environs of the City of Magnolia.

GUD Docket 9488-9512
Prepared filing and testimony of behalf of West Texas Gas 2004 rate increase for the environs of cities served.

GUD Docket 8033
Filed testimony on behalf of Southern Union Gas Company's 1991 appeal for a rate increase in South Jefferson County.

Railroad Commission of Texas-cont.

GUD Docket 7878
Filed testimony and prepared the rate filing on behalf of Southern Union Gas Company's 1991 request for a rate increase in the Austin environs.

GUD Docket 6968
Assisted in the analysis of Southern Union Gas Company's 1987 appeal for a rate increase on the behalf of the City of Austin

Public Service Commission of Montana
Docket D2017.9.80
Filed testimony and prepared the cost of service and rate design, developed and explained the proposed Gas Infrastructure Reliability Clause (GIRC) and addressed the negative acquisition adjustment in the Energy West Montana's 2017/2018 rate filing.

Public Utility Commission of Ohio
Case Nos. 18-1720-GA-AIR; 18-1721-GA-ATA; 18-1722-GA-AAM
Filed testimony and prepared the cost of service and rate design, developed and explained the proposed Gas Infrastructure Clause in Northeast Ohio's 2018/2019 rate filing.

Oklahoma Corporation Commission
Docket No. 001345
Presented testimony and prepared the rate filing on behalf of Southern Union Gas Company's 1992 rate request.

Pennsylvania Public Utility Commission
Docket No. 2013-2386293
Assisted the University of Pennsylvania with the analysis of Veolia Energy Philadelphia Inc.'s 2013 steam rate case.

Docket No. 2009-2111011
Assisted the University of Pennsylvania with the analysis of Trigen-Philadelphia Energy Corp's 2009 steam rate case.

Public Service Commission of West Virginia
Case No. 20-0746-G-42T
Filed testimony on behalf of the Gas and Oil Association of West Virginia Inc. regarding Hope Gas Inc.'s 2020 Application for a rate increase impacting the Gathering class.

Case No. 19-0549-G-BC
Filed testimony on behalf of the Independent Oil and Gas Association of West Virginia Inc. regarding Hope Gas Inc.'s 2019 Application for consent and approval for an asset conveyance agreement with an affiliate.

Federal Energy Regulatory Commission
Docket No. RP19-1353-000
Filed testimony on behalf of municipal and LDC customers of Northern Natural Gas' 2019 rate increase Section 4 rate increase.

FERC-cont.

Docket No. RP09-791-000
Assist municipal customers of MoGas analyze issues in FERC 2009 gas transportation rate case.

City of Austin

- Presented testimony and prepared filing as well as conducted settlement negotiations associated with Southern Union's 1993 rate request.
- Presented testimony and prepared filing on behalf of Southern Union Gas Company's 1991 rate request.
- Assisted in the analysis of Southern Union Gas Company's 1987 rate request on behalf of the City of Austin.

City of El Paso Public Service Board

- Presented testimony and prepared filing as well as participated in the settlement negotiations of Southern Union's 1993 rate request.
- Presented testimony and prepared filing on behalf of Southern Union Gas Company 1991 rate request.
- Presented testimony and prepared the filing on behalf of Southern Union Gas Company 1990 request.

City of Port Arthur

- Presented testimony and prepared filing on behalf of Southern Union Gas Company's 1991 rate request.
- Participated in Southern Union Gas Company's 1990 rate request.

City of Monahans

- Presented testimony and prepared filing on behalf of Southern Unions Gas Company's 1992 rate request.
- Assisted in the analysis of Southern Union Gas Company's 1989 rate request on the behalf of the City of Monahans.

City of Borger

- Prepared testimony and prepared the filing on behalf of Southern Union Gas Company's 1992 rate request.

City of Borger-cont.

- Participated in Southern Union Gas Company's 1989 rate request on the behalf of the City of Borger.

City of Galveston

- Presented testimony and prepared the filing on behalf of Southern Union Gas Company's 1992 rate request.

Other Gas Related Engagements

City of Laurens, South Carolina
Developed cost of service and rate design study 2018

Lower Valley Energy Distribution Cooperative – Afton, Wyoming
Developed cost of service and rate design study 2017/2018

City of Clinton, South Carolina
Developed cost of service and rate design study 2016/2017

City of Alexandria, Louisiana
Financial review, allocated cost of service and rate study for the gas system 2012/2013

Other Gas Related Engagements-cont.

City of George West, Texas
Gas utility rate study 2011/2012
EPCOR
Report and analysis of Gas IOU's and their regulation in the State of Texas

Mitchell County Utility
Assist with divestiture of gas utility assets

EPCOR Natural Gas
Ongoing assistance with GRIP filings

Markwest Energy Partners
Ongoing transportation rates and regulatory consulting

Consolidated Asset Management Services (CAMS)
Ongoing assistance regarding RRC Transmission pipeline issues

Alamo Transmission
Assisted with initial tariff development and related cost of service

Dynamic Energy Concepts Incorporated
Assisted with the review of gas contracts, tariffs, analyzed usage data and assessed procurement practices for a number of US Veteran Hospitals across the country.

ELECTRIC UTILITY RATES AND REGULATION EXPERIENCE

Public Utility Commission of Texas
Docket No, 51611
Prepared a cash working capital study and testimony on behalf of Sharyland Utilities L.L.C's's 2020 Rate Application to establish transmission rates.

Docket No.51546
Prepared the 2019/2020 Application for Interim Update of Wholesale Transmission Rates and testimony for Wood County Electric COOP

Docket No.51526
Prepared the 2019/2020 Application for Update of Wholesale Transmission Rates and testimony for the Brownsville Public Utility Board.

Docket No.51195
Prepared the 2019/2020 Application for Interim Update of Wholesale Transmission Rates and testimony for Houston County Electric COOP

Public Utility Commission of Texas-cont.

Docket No.50288
Prepared the 2018/2019 Application for Update of Wholesale Transmission Rates and testimony for the Kerrville Public Utility Board.

Docket No.50263
Prepared the 2018/2019 Application for Interim Update of Wholesale Transmission Rates and testimony for Houston County Electric COOP

Docket No. 49584
Prepared the 2018/2019 Application for Interim Update of Wholesale Transmission Rates and testimony for Pedernales Electric COOP

Docket No. 48840
Prepared the 2018/2019 Application for Interim Update of Wholesale Transmission Rates and testimony for Guadalupe Valley Electric COOP

Docket No. 48002
Prepared the 2018 Application for Interim Update of Wholesale Transmission Rates and testimony for Guadalupe Valley Electric COOP

Docket No. 46710
Prepared the 2016/2017 Application for Interim Update of Wholesale Transmission Rates and testimony for Guadalupe Valley Electric COOP.

Docket No, 45414
Prepared a cash working capital study and testimony on behalf of Sharyland Utilities L.P.'s 2016 Rate Application to establish retail distribution rates.

Docket No. 43731
Prepared a cash working capital study and testimony on behalf of Cross Texas Transmission LLC 2015 Rate Application to establish rates.

Docket No. 41474
Prepared a cash working capital study and testimony on behalf of Sharyland Utilities L.P.'s 2013 Rate Application to establish retail distribution rates.

Docket No. 31250
Presented testimony and rate filing on behalf of Rio Grande Electrical Cooperatives 2005 Change in rates for wholesale transmission service.

Docket No. 8702
Assisted in the analysis of Gulf States Utilities 1987 rate request.

Docket 8646
Assisted in the analysis of Central Power & Light's 1988 rate request.

Public Utility Commission of Texas-cont.

Docket 7661
Assisted in the analysis of the City of Fredericksburg's proposed amendment to Certificate of Convenience.

Docket 7510
Assisted in the analysis of West Texas Utilities Company's 1987 rate request.

Federal Energy Regulatory Commission
Docket No. ER88-202-0000
Assisted in the analysis of the Maine Yankee Atomic Power Plant Decommissioning.

Docket No. ER88-224-0000
Assisted in the analysis of the Carolina Power & Light Company Atomic Power Plant Decommissioning.

City of Bryan
- Developed and programmed data management system for the city electric department.

City of Fredericksburg
- Organized and performed an electric rate survey of Central Texas.
- Assisted in a load and rate design study.

City of Austin
- Assisted in the analysis of the City Electric Utility Department's 1989 rate request.

Other Electric Related Engagements

Dynamic Energy Concepts Incorporated
Assisted with the review of electric contracts, tariffs, analyzed usage data and assessed procurement practices for a number of US Veteran Hospitals across the country

H.E. Butt Grocery Company
Electricity procurement assistance and analysis of supply alternatives

Martin Marietta Materials
Electricity procurement assistance and analysis of supply alternatives

C.H. Guenther & Son, Inc.
Electricity procurement assistance and analysis of supply alternatives

Van Tuyl, Inc.
Electricity procurement assistance and analysis of supply alternatives

Northeast Texas Electrical Cooperative
- Ongoing review/analysis of Southwest Power Administration's annual Integrated Power Repayment Studies and resulting rates.
- Ongoing review/analysis of Southwest Electric Power Company's annual formulary wholesale rate adjustments.

Other Electric Related Engagements-cont.

Tex-La Electric Cooperative

- Ongoing review/analysis of Southwest Power Administration's annual Integrated Power Repayment Studies and resulting rates.

- Ongoing review/analysis of Southwest Electric Power Company's annual formulary wholesale rate adjustments

Sam Rayburn G&T Electrical Cooperative

- Ongoing review/analysis of Southwest Power Administration's annual Integrated Power Repayment Studies and resulting rates.

- Ongoing review/analysis of Southwest Power Administration's annual Robert D. Willis Power Repayment Studies and resulting rates.

East Texas Electrical Cooperative

- Ongoing review/analysis of Southwest Electric Power Company's annual formulary wholesale rate adjustments

- Ongoing review/analysis of Southwest Power Administration's annual Robert D. Willis Power Repayment Studies and resulting rates.

WATER UTILITY RATES AND REGULATION EXPERIENCE

Arizona Corporation Commission
Docket No. WS-01303A-006-0403
Presented testimony, prepared the Cost of Service study and rate design on behalf of Arizona-American Sun City and Sun City West Wastewater rate request.

Docket No. WS-01303A-06-0403
Presented testimony, prepared the Cost of Service study and rate design on behalf of Arizona-American Anthem/Aqua Fria Water and Wastewater rate request.

Docket No. WS-01303A-06-0014
Presented testimony, prepared the Cost of Service study, rate design, and assisted with the preparation of the revenue requirements on behalf of Arizona-American Mohave Water and Wastewater rate request.

Docket No. W-01656A-98-0577, SW-02334A-98-0577
Presented testimony for approval of a Central Arizona Project Water utilization plan, the implementation of a Groundwater Savings Fee and the recovery of deferred project costs.

Docket WS-02334A-98-0569
Presented a filing for the approval of an agreement relating to a wastewater plant de-nitrification project with the Sun City Recreation Centers and Del Webb Corporation.

Arizona Corporation Commission-cont.

Docket U-3454-97-599
Prepared and presented a filing for the approval of a CCN to provide water and wastewater services to Del Webb's Anthem project and the approval of two related agreements.

Docket No. E-1032-95-417 ET AL.
Presented testimony and prepared the rate filing on behalf of Citizens Utilities Maricopa County water properties 1995 rate request.

Arkansas Public Service Commission
Docket No. 09-130-U
Presented pro forma adjustments to revenues and prepared the Cost of Service study and rate design on behalf of United Water Arkansas's 2009 rate request.

Docket No. 06-160-U
Presented testimony, prepared the Cost of Service study and rate design on behalf of United Water Arkansas's 2006 rate request.

Docket No. 03-161-U
Presented testimony, prepared the Cost of Service study, rate design, and assisted with the preparation of the revenue requirements on behalf of United Water Arkansas's 2003 rate request.

Connecticut Department of Public Utility Control
Docket No. 07-05-44
Prepared the rate filing and supporting testimony on behalf of United Water Connecticut's 2007 water rate request.

Public Service Commission of South Carolina
Docket No. 2019 -281-S
Represented the Commission Staff in the analysis and recommended accounting treatment of a IOU's purchase of donated property from a Municipality.

Docket No. 2014-346-WS
Represented ratepayers in Daufuskie Island Utility Company's 2014 Request for Increase for Water and Sewer Rates and in the Rehearing or Supreme Court Remand in 2017. Filed Testimony in both proceedings.

Public Service Commission of Delaware
PSC Docket No. 16-0163
Presented testimony, prepared the Revenue Requirements Schedules, Cost of Service study and rate design on behalf of SUEZ Water Delaware's 2016 rate request

PSC Docket No. 09-60
Presented testimony, prepared the Cost of Service study and rate design on behalf of United Water Delaware's 2009 rate request.

PSC Docket No. 06-174
resented testimony, prepared the Cost of Service study, rate design, revenue normalization and cash working capital requirements on behalf of United Water Delaware's 2006 rate request.

Hawaii Public Utilities Commission
Docket 2019-0057
Filed testimony on revenue requirements, rate design and original cost trending study on behalf of Kalaeloa Water Company's water and wastewater systems.

Idaho Public Utilities Commission
Case No. UWI-W-09-01
Presented testimony, prepared revenue and expense pro forma adjustments, and proposed rate design on behalf of United Water Idaho, Inc. 2010 rate request.

***Indiana Utility Regulatory* Commission**
Cause No. 41842
Prepared the filing and presented testimony for the Petition of Utility Center Inc. for the recovery of Distribution System Improvement Charges -2001

Cause No. 41559
Prepared the filing and presented testimony for a Certificate of Territorial Authority to render Sewage service.- 2000

Cause No. 41968
Directed the preparation of Utility Center Inc.' request for authority to increase its rates and charges for water and sewer service. -2000

Illinois Commerce Commission
Docket No. 94-0481
Presented testimony and prepared the filing on behalf of Citizens Utilities Company of Illinois 1994 rate request.

Docket No. 95-0633
Presented testimony on behalf of Citizens Utilities Company of Illinois in Tudor Park Apartments vs. Citizens Utilities of Illinois.- 1995

Docket No. 97-0372
Presented testimony on behalf of Citizens Utilities of Illinois in the Application for Consent to and Approval of a Contract with Affiliated Interests. 1997

State Board of New Jersey Public Utilities
BPU Docket No. WRO702125
Prepared and presented testimony on the determination of the cash working capital requirements on behalf of United Water New Jerseys 2007 rate request.

New Mexico Public Regulation Commission
Case No. 18-00124-UT
Presented testimony and assisted with the preparation of the water rate filing on behalf of EPCOR Water New Mexico Clovis District 2018/2019 Rate Request

Case No. 11-00196-UT
Presented testimony and assisted with the preparation of the water rate filing on behalf of New Mexico American Water Company Clovis District 2011 Rate Request

New Mexico Public Regulation Commission-cont

Case No. 09-00156-UT
Presented testimony and prepared the water rate filing on behalf of New Mexico American Water Company Edgewood District 2009 Rate Request

Case No. 07-00435-UT
Presented testimony and prepared the water and wastewater rate filing on behalf of New Mexico Utilities Inc.2007 Rate Request

Case No. 08-00134-UT
Presented testimony and prepared the water rate filing on behalf of New Mexico –American Water Co.2008 Rate Request

New York Public Service Commission
Presented testimony, prepared the Cost of Service study and rate design on behalf of United Water New Rochelle's 2010 rate request.

Public Utilities Commission of Ohio
Docket No. 98-178-WS-AIR
Presented testimony and prepared the filing on behalf of Citizens Utilities Company of Ohio 1998 rate request.

Docket No. 94-1237
Presented testimony and prepared the filing on behalf of Citizens Utilities Company of Ohio 1994 rate request.

Pennsylvania Public Utility Commission
Docket Nos. R-2018-3002645and R-2018-3002647
Filed testimony on behalf of People's Natural Gas of Pittsburgh regarding Pittsburgh Water and Sewer Authority's 2018 rate increase request.

Docket No. R-2009-2122887
Presented testimony, prepared the Cost of Service study and rate design on behalf of United Water Pennsylvania's 2009 rate request.

Docket No. R-00051186
Assisted with analysis/filing preparation of United Water Pennsylvania, Inc. 2005 Rate Case.

Docket No. R-00953300
Presented testimony on behalf of Citizens Utilities Company of Pennsylvania 1995 rate request.

Public Utility Commission of Texas
Docket 50197
Application for a 2019 Water Rate Tariff Change for Timbercrest Partners LLC. Prepared the application for a Class B Water Utility.

Docket 49367
Petition by Out of District Ratepayers Appealing the Water Rates Established by the El Paso Water Control and Improvement District No. 4. Filed an Affidavit on behalf of the WCID and assisted in settlement negotiations.

Public Utility Commission of Texas-cont.

Docket 49892
Application for a 2019 Water Rate Tariff Change for Concho Rural Water Corporation. Prepared the application for a Class B Water Utility.

Docket 47680
Application for a 2018 Sewer Rate Tariff Change of Bolivar Utility Services Assisted with the preparation of the application and filed supporting testimony.

Docket 43242
Application for a 2014 Water Rate Tariff Change of Wiedenfeld Water Works. Prepared the application and filed testimony

Docket 44911
Application for a 2015 Sewer Rate Tariff Change of Bolivar Utility Services. Assisted in the preparation of the application

Docket 44809
Application for a 2015 Water/Sewer Rate Tariff Change of Quadvest LP. Prepared the application and filed testimony

Docket 47680
Application for a 2018 Sewer Rate Tariff Change of Bolivar Utility Services. Assisted in the preparation of the application and filed testimony

Texas Commission of Environmental Quality
SOAH Docket 582-14-3415
Application for a 2013 Water Rate/Tariff Change of Canyon Lake Water Service Company
Prepared the application and filed testimony on behalf of Canyon Lake WSC.

SOAH Docket No. 582-14-3384
Application for a 2013 Water and Sewer Rate/Tariff Change of SWWC Inc.
Prepared application on behalf of SWWC, Inc.

SOAH 582-14-3381
Application for a 2013 Water and Sewer Rate/Tariff Change of Monarch Utilities LP
Prepared application on behalf of SWWC, Inc.

SOAH Docket No. 582-12-0224
STM Application of Monarch Utilities I, L.P. to Transfer Water and Sewer Facilities and Certificates of Convenience and Necessity – provided assistance

Application 37531-R
Application for a Water Rate/Tariff Change of Quadvest L.P. Prepared application on behalf of Quadvest L.P.
Prepared application on behalf of Quadvest L.P.

***Texas Commission of Environmental Quality*-cont.**

Applications 37507-R and 37508-R
Application for a Water and Sewer Rate/Tariff Change of Ranch Utilities, Inc. Prepared application on behalf of Ranch Utilities, Inc.

Application 37317-R
Application for a Water Rate/Tariff Change of Wiedenfeld Water Works, Inc. Prepared application on behalf of Wiedenfeld Water Works, Inc.

Applications 37234-R and 37235-R
Application for a Water and Sewer Rate/Tariff Change of Aqua Texas, Inc. North and Southwest Regions Prepared application on behalf of Aqua Texas, Inc.

SOAH Docket No, 582-12-0224
Application for a Water and Sewer Rate/Tariff Change of Monarch Utilities LP
Prepared application on behalf of SWWC, Inc.

SOAH Docket No. 582-11-1468
Application for a 2010 Water Rate/Tariff Change of Canyon Lake Water Service Company
Prepared the application and filed testimony on behalf of Canyon Lake WSC.

SOAH Docket No. 582-11-1458
Application for a Water and Sewer Rate/Tariff Change of Aqua Texas, Inc. Southeast Region
Prepared application on behalf of Aqua Texas, Inc.

Docket No. 0580-UCR
Application for a 2009 Water Rate/Tariff Change of Canyon Lake Water Service Company
Prepared the application on behalf of Canyon Lake WSC.

Docket No. 35850-R
Application for a 2007 Water Rate/Tariff Change of Canyon Lake Water Service Company
Prepared the application on behalf of Canyon Lake WSC.

Docket No. 33763-R
Application for a 2007 Water and Sewer Rate/Tariff Change of Midway, Inc. For the City of Oak Point Service area. Filing initially made with the City of Oak Point.

Docket Nos. 35748-R & 35747-R
Application for a Water and Sewer Rate/Tariff Change of Monarch Utilities LP
Prepared the application on behalf of Monarch.

Docket No. 2006-0072-UCR
Application for a Water and Sewer Rate/Tariff Change of Aqua Texas, Inc
Prepared application and presented testimony on behalf of Aqua Texas, Inc.

***Texas Commission of Environmental Quality*-cont.**

Docket No. 2007-0478-UCR
Application for a Water and Sewer Rate/Tariff Change of Texas American Water Inc.
Prepared the application on behalf of Texas American Water.

Docket No. 2005-0114-UCR
Application for a Water and Sewer Rate/Tariff Change of Aqua Texas, Inc
Presented Testimony on behalf of Aqua Texas, Inc.

Docket No. 2004-2029-UCR
Application for a Water and Sewer Rate/Tariff Change of Walker Water Works, Inc.
Prepared the application on behalf of Texas American Water.

Application Nos. 34658-R & 34659-R
Application for a Water and Sewer Rate/Tariff Change of Southwest Utilities, Inc.
Prepared the application on behalf of Texas American Water.

Docket Nos. 2000-1074-UCR, 2000-1075-UCR, 2000-1366 UCR through 2000-1369 UCR
Assisted in the preparation and presentation of the Aqua Source 2000 rate increase

Application No. 7371-R (Texas Water Commission)
Assisted in the analysis of Southern Utilities 1988 rate request on the behalf of Southern Utilities customers.

Other Water Related Engagements and Expert Proceedings

Hawaii Water Service Company
Regulatory Filing Assistance Regarding the Acquisition of Kalaeloa Water Company

Ector County Municipal Utility District
Assisted with wholesale water rate contract negotiations with the City of Odessa

South Carolina Office of Regulatory Staff
Assisted with the review of Palmetto Utilities Inc. Certain Assets acquired from City of Columbia, S.C.

The Landings Association – Savannah, Georgia
Assist with the annual review of water and sewer rate adjustments proposed by Utilities Inc of Georgia according to Settlement Agreement

The City of Hutto, Texas
Independent Valuation, Assessment and Analysis of the Proposed Acquisition of a Wholesale Water Supply Company by the City of Hutto

EPCOR Water
- Assist with the Valuation and Analysis Associated with the Proposed Condemnation of the Bullhead City Water Utility
- Assist with the Analysis Regarding the Rate Consolidation Options for EPCOR's 11 Arizona Rate Districts

Other Water Related Engagements and Expert Proceedings-cont.

Woodland Oaks Utilities, Conroe Texas
Assist with the Texas PUC Transition

City of Laurens, South Carolina
Developed water/wastewater cost of service and rate design study 2018

City of Clinton, South Carolina
Developed cost of service and rate design study 2016/2017

City of Vinton, Texas
Valuation and Analysis of Hillside Water Works Divestiture

City of Alexandria, Louisiana
Financial review, allocated cost of service and rate study for the gas system 2012/2013

Town of Providence Village, Texas
Developed Expert Witness Report for Denton County Court Cause No. 2011-60876-393
Analysis of Divestiture and Operating Agreements between Mustang SUD and Providence Village WCID

City of Page, Arizona
Developed retail water and wastewater rate model, recommended retail water and wastewater rates and provided results and recommendations in a written report and presentation to the City of Page Council

Mitchell County Utility, Texas
Assist with valuation, analysis, and divestiture of MCU's water utility assets

City of Longview, Texas
Ongoing assistance with development of annual formulary wholesale water and wastewater rates.

Aqua Texas, Inc.
Calculations and updates of Regional Uniform CIAC Fees

Dripping Springs WSC, Hays County WCID 1&2
Review and analysis of West Travis County Public Utility Agency wholesale rate cost of service and rate increase 2012.

SWWC Inc.

- Decertification analysis and valuation of the CCN for Crosswinds Divestiture
- Decertification analysis and valuation of the CCN for TXI Divestiture
- Decertification analysis and valuation of the CCN for Tower Terrace/Kilgore Tract Divestiture
- Decertification analysis and valuation of the CCN for Villages at Warner Ranch Divestiture
- Long term forecast of all components of the revenue requirements of all Texas utilities
- City of Blue Mound Condemnation of SWWC Water Utility- Valuation Assistance

Other Water Related Engagements and Expert Proceedings-cont.

- Assist with Analysis of Public Water Supply Divestiture in Louisiana
- Monarch Stock, Merger, Transfer (STM) Application Assistance

Crystal Clear WSC
Decertification analysis and valuation of the CCN for Texas GLO development area around New Braunfels Texas

Woodbine Development Corp.
Analysis and assistance with LCRA Windmill Ranch wholesale wastewater services contract renegotiations.

Canyon Lake Water Supply Company (San Jose Water)
- Valuation and Analysis of Clear Water Estates Acquisition for PUC STM Filing
- Valuation and Analysis of HEB Water and Wastewater Asset Divestiture
- Analysis and Forecast Regarding the Proposed Merger of Rebecca Creek Municipal Utility District
- Valuation of Bulverde Systems Purchased from Blanco River Authority

Aransas Bay Utilities Company, LLC
Valuation and Analysis of Water and Wastewater Assets for Proposed Divestiture.

Global Water Resources
Expert witness before American Arbitration Association regarding the financial standing and regulatory status of Global Water.

Corix Utilities
Assistance with due diligence, regulatory strategy analysis and bid preparation regarding the LCRA retail water and wastewater divestiture

Golden State Water Company
Assistance with analysis and bid concerning divestiture of SWWC Inc.

SUEZ Utilities
- Texas Regulatory Assessment of Water/Wastewater Utility Divestiture
- City of Scranton Wastewater Concession (Privatization) Due Diligence/Analysis
- City of O'Fallon, Illinois Water/Wastewater Concession (Privatization) Due Diligence/Analysis
- City of Rahway, New Jersey Concession Project (Privatization) Due Diligence/Analysis
- McKeesport Pennsylvania Concession (Privatization) Due Diligence/Analysis

Austin Apartment Association
Represented the Multi-Family water and wastewater classes in the City of Austin's Public Involvement Committee to review the 2017 water and wastewater rate study.

Other Water Related Engagements and Expert Proceedings-cont.

Greater Austin Water Forum
Assisted industrial class water users with analysis and participation in the City of Austin 2008 Cost of Service Study.

New Mexico Utilities
Review/analysis and critique report on Albuquerque Bernalillo County Water Utility Authority's Cost of Service Wholesale Wastewater Rate Model

Hays County Water Control & Improvement District No. 1 and No. 2
Developed 2015/2016 retail water and wastewater rate model, recommended retail water and wastewater rates and provided results and recommendations in a written report and presentation to the Boards of each utility.

LIST OF TESTIMONY, EXPERT PROCEEDINGS, AND ENGAGEMENTS BY CHARLES E. LOY, CPA

GAS UTILITY RATES AND REGULATION EXPERIENCE

Railroad Commission of Texas

GUD Docket OS-21-00007153
Prepared the filing schedules on behalf of Universal Gas for the Review and Securitization of Extraordinary Costs due to winter storm Uri.

GUD Docket OS-21-00007058
Assisted with the preparation of the filing schedules on behalf of CoServ Natural Gas Ltd. for the Review and Securitization of Extraordinary Costs due to winter storm Uri.

GUD Docket OS-20-00005136
Prepared cost of service and rate design and testimony of behalf of CoServ Gas, Ltd 2020 application, to increase rates in the incorporated and unincorporated areas it serves.

GUD Docket OS-20-00004865
Prepared consolidated filing and testimony of behalf of Universal Natural Gas, Inc., to Increase and Consolidate Rates in the Unincorporated Areas Served by Universal Natural Gas, LLC, d/b/a Universal Natural Gas, Inc. Consumers Gas Company, LLC d/b/a Consumers Gas Company Inc., Enertex NB, LLC, and Gas Energy, LLC

GUD Docket OS-20-00004866
Prepared consolidated filing and testimony of behalf of Hooks Gas Pipeline, LLC to Increase and Consolidate Rates for Hooks Gas Pipeline, LLC, Texas Gas Pipeline Company, LLC, and 1486 Gas Pipeline, LLC

GUD Docket 10988
Prepared filing and testimony of behalf of EPCOR Texas Gas 2020 rate increase for the environs of the City of Magnolia.

GUD Docket 10190
Prepared filing and testimony of behalf of Hughes Natural Gas 2012 rate increase for the environs of the City of Magnolia.

GUD Docket 10083
Prepared filing and testimony of behalf of Hughes Natural Gas 2011 rate increase for the incorporated area of the City of Magnolia and environs.

GUD Docket 9731
Prepared filing and testimony of behalf of Hughes Natural Gas 2007 rate increase for the environs of the City of Magnolia.

Railroad Commission of Texas-cont.

GUD Docket 9488-9512
Prepared filing and testimony of behalf of West Texas Gas 2004 rate increase for the environs of cities served.

GUD Docket 8033
Filed testimony on behalf of Southern Union Gas Company's 1991 appeal for a rate increase in South Jefferson County.

GUD Docket 7878
Filed testimony and prepared the rate filing on behalf of Southern Union Gas Company's 1991 request for a rate increase in the Austin environs.

GUD Docket 6968
Assisted in the analysis of Southern Union Gas Company's 1987 appeal for a rate increase on the behalf of the City of Austin

Public Service Commission of Montana
Docket D2017.9.80
Filed testimony and prepared the cost of service and rate design, developed and explained the proposed Gas Infrastructure Reliability Clause (GIRC) and addressed the negative acquisition adjustment in the Energy West Montana's 2017/2018 rate filing.

Public Utility Commission of Ohio
Case Nos. 18-1720-GA-AIR; 18-1721-GA-ATA; 18-1722-GA-AAM
Filed testimony and prepared the cost of service and rate design, developed and explained the proposed Gas Infrastructure Clause in Northeast Ohio's 2018/2019 rate filing.

Oklahoma Corporation Commission
Docket No. 001345
Presented testimony and prepared the rate filing on behalf of Southern Union Gas Company's 1992 rate request.

Pennsylvania Public Utility Commission
Docket No. 2013-2386293
Assisted the University of Pennsylvania with the analysis of Veolia Energy Philadelphia Inc.'s 2013 steam rate case.

Docket No. 2009-2111011
Assisted the University of Pennsylvania with the analysis of Trigen-Philadelphia Energy Corp's 2009 steam rate case.

Public Service Commission of West Virginia
Case No. 20-0746-G-42T
Filed testimony on behalf of the Gas and Oil Association of West Virginia Inc. regarding Hope Gas Inc.'s 2020 Application for a rate increase impacting the Gathering class.

Case No. 19-0549-G-BC
Filed testimony on behalf of the Independent Oil and Gas Association of West Virginia Inc. regarding Hope Gas Inc.'s 2019 Application for consent and approval for an asset conveyance agreement with an affiliate.

Federal Energy Regulatory Commission
Docket No. RP19-1353-000
Filed testimony on behalf of municipal and LDC customers of Northern Natural Gas' 2019 rate increase Section 4 rate increase.

Docket No. RP09-791-000
Assist municipal customers of MoGas analyze issues in FERC 2009 gas transportation rate case.

City of Austin
- Presented testimony and prepared filing as well as conducted settlement negotiations associated with Southern Union's 1993 rate request.
- Presented testimony and prepared filing on behalf of Southern Union Gas Company's 1991 rate request.
- Assisted in the analysis of Southern Union Gas Company's 1987 rate request on behalf of the City of Austin.

City of El Paso Public Service Board
- Presented testimony and prepared filing as well as participated in the settlement negotiations of Southern Union's 1993 rate request.
- Presented testimony and prepared filing on behalf of Southern Union Gas Company 1991 rate request.
- Presented testimony and prepared the filing on behalf of Southern Union Gas Company 1990 request.

City of Port Arthur
- Presented testimony and prepared filing on behalf of Southern Union Gas Company's 1991 rate request.
- Participated in Southern Union Gas Company's 1990 rate request.

City of Monahans
- Presented testimony and prepared filing on behalf of Southern Unions Gas Company's 1992 rate request.
- Assisted in the analysis of Southern Union Gas Company's 1989 rate request on the behalf of the City of Monahans.

City of Borger
- Prepared testimony and prepared the filing on behalf of Southern Union Gas Company's 1992 rate request.

City of Borger-cont.
- Participated in Southern Union Gas Company's 1989 rate request on the behalf of the City of Borger.

City of Galveston
- Presented testimony and prepared the filing on behalf of Southern Union Gas Company's 1992 rate request.

Other Gas Related Engagements

City of Laurens, South Carolina
Developed cost of service and rate design study 2018

Lower Valley Energy Distribution Cooperative – Afton, Wyoming
Developed cost of service and rate design study 2017/2018

City of Clinton, South Carolina
Developed cost of service and rate design study 2016/2017

Other Gas Related Engagements-cont.

City of Alexandria, Louisiana
Financial review, allocated cost of service and rate study for the gas system 2012/2013

City of George West, Texas
Gas utility rate study 2011/2012

EPCOR
Report and analysis of Gas IOU's and their regulation in the State of Texas

Mitchell County Utility
Assist with divestiture of gas utility assets

EPCOR Natural Gas
Ongoing assistance with GRIP filings

Markwest Energy Partners
Ongoing transportation rates and regulatory consulting

Consolidated Asset Management Services (CAMS)
Ongoing assistance regarding RRC Transmission pipeline issues

Alamo Transmission
Assisted with initial tariff development and related cost of service

Dynamic Energy Concepts Incorporated
Assisted with the review of gas contracts, tariffs, analyzed usage data and assessed procurement practices for a number of US Veteran Hospitals across the country.

ELECTRIC UTILITY RATES AND REGULATION EXPERIENCE

Public Utility Commission of Texas
Docket No, 51611
Prepared a cash working capital study and testimony on behalf of Sharyland Utilities L.L.C's's 2020 Rate Application to establish transmission rates.

Docket No.51546
Prepared the 2019/2020 Application for Interim Update of Wholesale Transmission Rates and testimony for Wood County Electric COOP

Docket No.51526
Prepared the 2019/2020 Application for Update of Wholesale Transmission Rates and testimony for the Brownsville Public Utility Board.

Public Utility Commission of Texas-cont.

Docket No.51195
Prepared the 2019/2020 Application for Interim Update of Wholesale Transmission Rates and testimony for Houston County Electric COOP

Docket No.50288
Prepared the 2018/2019 Application for Update of Wholesale Transmission Rates and testimony for the Kerrville Public Utility Board.

Docket No.50263
Prepared the 2018/2019 Application for Interim Update of Wholesale Transmission Rates and testimony for Houston County Electric COOP

Docket No. 49584
Prepared the 2018/2019 Application for Interim Update of Wholesale Transmission Rates and testimony for Pedernales Electric COOP

Docket No. 48840
Prepared the 2018/2019 Application for Interim Update of Wholesale Transmission Rates and testimony for Guadalupe Valley Electric COOP

Docket No. 48002
Prepared the 2018 Application for Interim Update of Wholesale Transmission Rates and testimony for Guadalupe Valley Electric COOP

Docket No. 46710
Prepared the 2016/2017 Application for Interim Update of Wholesale Transmission Rates and testimony for Guadalupe Valley Electric COOP.

Docket No, 45414
Prepared a cash working capital study and testimony on behalf of Sharyland Utilities L.P.'s 2016 Rate Application to establish retail distribution rates.

Docket No. 43731
Prepared a cash working capital study and testimony on behalf of Cross Texas Transmission LLC 2015 Rate Application to establish rates.

Docket No. 41474
Prepared a cash working capital study and testimony on behalf of Sharyland Utilities L.P.'s 2013 Rate Application to establish retail distribution rates.

Docket No. 31250
Presented testimony and rate filing on behalf of Rio Grande Electrical Cooperatives 2005 Change in rates for wholesale transmission service.

Public Utility Commission of Texas-cont.

Docket No. 8702
Assisted in the analysis of Gulf States Utilities 1987 rate request.

Docket 8646
Assisted in the analysis of Central Power & Light's 1988 rate request.

Docket 7661
Assisted in the analysis of the City of Fredericksburg's proposed amendment to Certificate of Convenience.

Docket 7510
Assisted in the analysis of West Texas Utilities Company's 1987 rate request.

Federal Energy Regulatory Commission
Docket No. ER88-202-0000
Assisted in the analysis of the Maine Yankee Atomic Power Plant Decommissioning.

Docket No. ER88-224-0000
Assisted in the analysis of the Carolina Power & Light Company Atomic Power Plant Decommissioning.

City of Fredericksburg
- Organized and performed an electric rate survey of Central Texas.
- Assisted in a load and rate design study.

City of Austin
- Assisted in the analysis of the City Electric Utility Department's 1989 rate request.

Other Electric Related Engagements
Dynamic Energy Concepts Incorporated
Assisted with the review of electric contracts, tariffs, analyzed usage data and assessed procurement practices for a number of US Veteran Hospitals across the country

H.E. Butt Grocery Company
Electricity procurement assistance and analysis of supply alternatives

Martin Marietta Materials
Electricity procurement assistance and analysis of supply alternatives

C.H. Guenther & Son, Inc.
Electricity procurement assistance and analysis of supply alternatives

Van Tuyl, Inc.
Electricity procurement assistance and analysis of supply alternatives

Northeast Texas Electrical Cooperative
- Ongoing review/analysis of Southwest Power Administration's annual Integrated Power Repayment Studies and resulting rates.

Other Electric Related Engagements-cont.

- Review/analysis of Southwest Electric Power Company's annual formulary wholesale rate adjustments.

Tex-La Electric Cooperative

- Review/analysis of Southwest Power Administration's annual Integrated Power Repayment Studies and resulting rates.

- Review/analysis of Southwest Electric Power Company's annual formulary wholesale rate adjustments

Sam Rayburn G&T Electrical Cooperative

- Review/analysis of Southwest Power Administration's annual Integrated Power Repayment Studies and resulting rates.

- Review/analysis of Southwest Power Administration's annual Robert D. Willis Power Repayment Studies and resulting rates.

East Texas Electrical Cooperative

- Review/analysis of Southwest Electric Power Company's annual formulary wholesale rate adjustments

- Review/analysis of Southwest Power Administration's annual Robert D. Willis Power Repayment Studies and resulting rates.

WATER UTILITY RATES AND REGULATION EXPERIENCE

Arizona Corporation Commission
Docket No. WS-01303A-006-0403
Presented testimony, prepared the Cost of Service study and rate design on behalf of Arizona-American Sun City and Sun City West Wastewater rate request.

Docket No. WS-01303A-06-0403
Presented testimony, prepared the Cost of Service study and rate design on behalf of Arizona-American Anthem/Aqua Fria Water and Wastewater rate request.

Docket No. WS-01303A-06-0014
Presented testimony, prepared the Cost of Service study, rate design, and assisted with the preparation of the revenue requirements on behalf of Arizona-American Mohave Water and Wastewater rate request.

Docket No. W-01656A-98-0577, SW-02334A-98-0577
Presented testimony for approval of a Central Arizona Project Water utilization plan, the implementation of a Groundwater Savings Fee and the recovery of deferred project costs.

Arizona Corporation Commission-cont

Docket WS-02334A-98-0569
Presented a filing for the approval of an agreement relating to a wastewater plant de-nitrification project with the Sun City Recreation Centers and Del Webb Corporation.

Docket U-3454-97-599
Prepared and presented a filing for the approval of a CCN to provide water and wastewater services to Del Webb's Anthem project and the approval of two related agreements.

Docket No. E-1032-95-417 ET AL.
Presented testimony and prepared the rate filing on behalf of Citizens Utilities Maricopa County water properties 1995 rate request.

Arkansas Public Service Commission
Docket No. 09-130-U
Presented pro forma adjustments to revenues and prepared the Cost of Service study and rate design on behalf of United Water Arkansas's 2009 rate request.

Docket No. 06-160-U
Presented testimony, prepared the Cost of Service study and rate design on behalf of United Water Arkansas's 2006 rate request.

Docket No. 03-161-U
Presented testimony, prepared the Cost of Service study, rate design, and assisted with the preparation of the revenue requirements on behalf of United Water Arkansas's 2003 rate request.

Connecticut Department of Public Utility Control
Docket No. 07-05-44
Prepared the rate filing and supporting testimony on behalf of United Water Connecticut's 2007 water rate request.

Public Service Commission of South Carolina
Docket No. 2019 -281-S
Represented the Commission Staff in the analysis and recommended accounting treatment of a IOU's purchase of donated property from a Municipality.

Docket No. 2014-346-WS
Represented ratepayers in Daufuskie Island Utility Company's 2014 Request for Increase for Water and Sewer Rates and in the Rehearing or Supreme Court Remand in 2017. Filed Testimony in both proceedings.

Public Service Commission of Delaware
PSC Docket No. 16-0163
Presented testimony, prepared the Revenue Requirements Schedules, Cost of Service study and rate design on behalf of SUEZ Water Delaware's 2016 rate request

PSC Docket No. 09-60
Presented testimony, prepared the Cost of Service study and rate design on behalf of United Water Delaware's 2009 rate request.

Public Service Commission of Delaware-cont.

PSC Docket No. 06-174
Presented testimony, prepared the Cost of Service study, rate design, revenue normalization and cash working capital requirements on behalf of United Water Delaware's 2006 rate request.

Hawaii Public Utilities Commission
Docket 2019-0057
Filed testimony on revenue requirements, rate design and original cost trending study on behalf of Kalaeloa Water Company's water and wastewater systems.

Idaho Public Utilities Commission
Case No. UWI-W-09-01
Presented testimony, prepared revenue and expense pro forma adjustments, and proposed rate design on behalf of United Water Idaho, Inc. 2010 rate request.

***Indiana Utility Regulatory* Commission**
Cause No. 41842
Prepared the filing and presented testimony for the Petition of Utility Center Inc. for the recovery of Distribution System Improvement Charges -2001

Cause No. 41559
Prepared the filing and presented testimony for a Certificate of Territorial Authority to render Sewage service.-2000

Cause No. 41968
Directed the preparation of Utility Center Inc.' request for authority to increase its rates and charges for water and sewer service. -2000

Illinois Commerce Commission
Docket No. 94-0481
Presented testimony and prepared the filing on behalf of Citizens Utilities Company of Illinois 1994 rate request.

Docket No. 95-0633
Presented testimony on behalf of Citizens Utilities Company of Illinois in Tudor Park Apartments vs. Citizens Utilities of Illinois.- 1995

Docket No. 97-0372
Presented testimony on behalf of Citizens Utilities of Illinois in the Application for Consent to and Approval of a Contract with Affiliated Interests. 1997

State Board of New Jersey Public Utilities
BPU Docket No. WRO702125
Prepared and presented testimony on the determination of the cash working capital requirements on behalf of United Water New Jerseys 2007 rate request.

New Mexico Public Regulation Commission
Case No. 18-00124-UT
Presented testimony and assisted with the preparation of the water rate filing on behalf of EPCOR Water New Mexico Clovis District 2018/2019 Rate Request

New Mexico Public Regulation Commission-cont

Case No. 11-00196-UT
Presented testimony and assisted with the preparation of the water rate filing on behalf of New Mexico American Water Company Clovis District 2011 Rate Request

Case No. 09-00156-UT
Presented testimony and prepared the water rate filing on behalf of New Mexico American Water Company Edgewood District 2009 Rate Request

Case No. 07-00435-UT
Presented testimony and prepared the water and wastewater rate filing on behalf of New Mexico Utilities Inc.2007 Rate Request

Case No. 08-00134-UT
Presented testimony and prepared the water rate filing on behalf of New Mexico –American Water Co.2008 Rate Request

New York Public Service Commission
Presented testimony, prepared the Cost of Service study and rate design on behalf of United Water New Rochelle's 2010 rate request.

Public Utilities Commission of Ohio
Docket No. 98-178-WS-AIR
Presented testimony and prepared the filing on behalf of Citizens Utilities Company of Ohio 1998 rate request.

Docket No. 94-1237
Presented testimony and prepared the filing on behalf of Citizens Utilities Company of Ohio 1994 rate request.

Pennsylvania Public Utility Commission
Docket Nos. R-2018-3002645and R-2018-3002647
Filed testimony on behalf of People's Natural Gas of Pittsburgh regarding Pittsburgh Water and Sewer Authority's 2018 rate increase request.

Docket No. R-2009-2122887
Presented testimony, prepared the Cost of Service study and rate design on behalf of United Water Pennsylvania's 2009 rate request.

Docket No. R-00051186
Assisted with analysis/filing preparation of United Water Pennsylvania, Inc. 2005 Rate Case.

Docket No. R-00953300
Presented testimony on behalf of Citizens Utilities Company of Pennsylvania 1995 rate request.

Public Utility Commission of Texas
Docket 50197
Application for a 2019 Water Rate Tariff Change for Timbercrest Partners LLC. Prepared the application for a Class B Water Utility.

Public Utility Commission of Texas-cont.

Docket 49367
Petition by Out of District Ratepayers Appealing the Water Rates Established by the El Paso Water Control and Improvement District No. 4. Filed an Affidavit on behalf of the WCID and assisted in settlement negotiations.

Docket 49892
Application for a 2019 Water Rate Tariff Change for Concho Rural Water Corporation. Prepared the application for a Class B Water Utility.

Docket 47680
Application for a 2018 Sewer Rate Tariff Change of Bolivar Utility Services Assisted with the preparation of the application and filed supporting testimony.

Docket 43242
Application for a 2014 Water Rate Tariff Change of Wiedenfeld Water Works. Prepared the application and filed testimony

Docket 44911
Application for a 2015 Sewer Rate Tariff Change of Bolivar Utility Services. Assisted in the preparation of the application

Docket 44809
Application for a 2015 Water/Sewer Rate Tariff Change of Quadvest LP. Prepared the application and filed testimony

Docket 47680
Application for a 2018 Sewer Rate Tariff Change of Bolivar Utility Services. Assisted in the preparation of the application and filed testimony

Texas Commission of Environmental Quality
SOAH Docket 582-14-3415
Application for a 2013 Water Rate/Tariff Change of Canyon Lake Water Service Company
Prepared the application and filed testimony on behalf of Canyon Lake WSC.

SOAH Docket No. 582-14-3384
Application for a 2013 Water and Sewer Rate/Tariff Change of SWWC Inc.
Prepared application on behalf of SWWC, Inc.

SOAH 582-14-3381
Application for a 2013 Water and Sewer Rate/Tariff Change of Monarch Utilities LP
Prepared application on behalf of SWWC, Inc.

SOAH Docket No. 582-12-0224
STM Application of Monarch Utilities I, L.P. to Transfer Water and Sewer Facilities and Certificates of Convenience and Necessity – provided assistance

***Texas Commission of Environmental Quality*-cont.**

Application 37531-R
Application for a Water Rate/Tariff Change of Quadvest L.P. Prepared application on behalf of Quadvest L.P. Prepared application on behalf of Quadvest L.P.

Applications 37507-R and 37508-R
Application for a Water and Sewer Rate/Tariff Change of Ranch Utilities, Inc. Prepared application on behalf of Ranch Utilities, Inc.

Application 37317-R
Application for a Water Rate/Tariff Change of Wiedenfeld Water Works, Inc. Prepared application on behalf of Wiedenfeld Water Works, Inc.

Applications 37234-R and 37235-R
Application for a Water and Sewer Rate/Tariff Change of Aqua Texas, Inc. North and Southwest Regions Prepared application on behalf of Aqua Texas, Inc.

SOAH Docket No, 582-12-0224
Application for a Water and Sewer Rate/Tariff Change of Monarch Utilities LP
Prepared application on behalf of SWWC, Inc.

SOAH Docket No. 582-11-1468
Application for a 2010 Water Rate/Tariff Change of Canyon Lake Water Service Company
Prepared the application and filed testimony on behalf of Canyon Lake WSC.

SOAH Docket No. 582-11-1458
Application for a Water and Sewer Rate/Tariff Change of Aqua Texas, Inc. Southeast Region
Prepared application on behalf of Aqua Texas, Inc.

Docket No. 0580-UCR
Application for a 2009 Water Rate/Tariff Change of Canyon Lake Water Service Company
Prepared the application on behalf of Canyon Lake WSC.

Docket No. 35850-R
Application for a 2007 Water Rate/Tariff Change of Canyon Lake Water Service Company
Prepared the application on behalf of Canyon Lake WSC.

Docket No. 33763-R
Application for a 2007 Water and Sewer Rate/Tariff Change of Midway, Inc. For the City of Oak Point Service area. Filing initially made with the City of Oak Point.

Docket Nos. 35748-R & 35747-R
Application for a Water and Sewer Rate/Tariff Change of Monarch Utilities LP
Prepared the application on behalf of Monarch.

***Texas Commission of Environmental Quality*-cont.**

Docket No. 2006-0072-UCR
Application for a Water and Sewer Rate/Tariff Change of Aqua Texas, Inc
Prepared application and presented testimony on behalf of Aqua Texas, Inc.

Docket No. 2007-0478-UCR
Application for a Water and Sewer Rate/Tariff Change of Texas American Water Inc.
Prepared the application on behalf of Texas American Water.

Docket No. 2005-0114-UCR
Application for a Water and Sewer Rate/Tariff Change of Aqua Texas, Inc
Presented Testimony on behalf of Aqua Texas, Inc.

Docket No. 2004-2029-UCR
Application for a Water and Sewer Rate/Tariff Change of Walker Water Works, Inc.
Prepared the application on behalf of Texas American Water.

Application Nos. 34658-R & 34659-R
Application for a Water and Sewer Rate/Tariff Change of Southwest Utilities, Inc.
Prepared the application on behalf of Texas American Water.

Docket Nos. 2000-1074-UCR, 2000-1075-UCR, 2000-1366 UCR through 2000-1369 UCR
Assisted in the preparation and presentation of the Aqua Source 2000 rate increase

Application No. 7371-R (Texas Water Commission)
Assisted in the analysis of Southern Utilities 1988 rate request on the behalf of Southern Utilities customers.

Other Water Related Engagements and Expert Proceedings

Hawaii Water Service Company
Regulatory Filing Assistance Regarding the Acquisition of Kalaeloa Water Company

Ector County Municipal Utility District
Assisted with wholesale water rate contract negotiations with the City of Odessa

South Carolina Office of Regulatory Staff
Assisted with the review of Palmetto Utilities Inc. Certain Assets acquired from City of Columbia, S.C.

The Landings Association – Savannah, Georgia
Assist with the annual review of water and sewer rate adjustments proposed by Utilities Inc of Georgia according to Settlement Agreement

The City of Hutto, Texas
Independent Valuation, Assessment and Analysis of the Proposed Acquisition of a Wholesale Water Supply Company by the City of Hutto

Other Water Related Engagements and Expert Proceedings-cont.

EPCOR Water

- Assist with the Valuation and Analysis Associated with the Proposed Condemnation of the Bullhead City Water Utility
- Assist with the Analysis Regarding the Rate Consolidation Options for EPCOR's 11 Arizona Rate Districts

Woodland Oaks Utilities, Conroe Texas
Assist with the Texas PUC Transition

City of Laurens, South Carolina
Developed water/wastewater cost of service and rate design study 2018

City of Clinton, South Carolina
Developed cost of service and rate design study 2016/2017

City of Vinton, Texas
Valuation and Analysis of Hillside Water Works Divestiture

City of Alexandria, Louisiana
Financial review, allocated cost of service and rate study for the gas system 2012/2013

Town of Providence Village, Texas
Developed Expert Witness Report for Denton County Court Cause No. 2011-60876-393
Analysis of Divestiture and Operating Agreements between Mustang SUD and Providence Village WCID

City of Page, Arizona
Developed retail water and wastewater rate model, recommended retail water and wastewater rates and provided results and recommendations in a written report and presentation to the City of Page Council

Mitchell County Utility, Texas
Assist with valuation, analysis, and divestiture of MCU's water utility assets

City of Longview, Texas
Ongoing assistance with development of annual formulary wholesale water and wastewater rates.

Aqua Texas, Inc.
Calculations and updates of Regional Uniform CIAC Fees

Dripping Springs WSC, Hays County WCID 1&2
Review and analysis of West Travis County Public Utility Agency wholesale rate cost of service and rate increase 2012.

Other Water Related Engagements and Expert Proceedings-cont.

SWWC Inc.

- Decertification analysis and valuation of the CCN for Crosswinds Divestiture
- Decertification analysis and valuation of the CCN for TXI Divestiture
- Decertification analysis and valuation of the CCN for Tower Terrace/Kilgore Tract Divestiture
- Decertification analysis and valuation of the CCN for Villages at Warner Ranch Divestiture
- Long term forecast of all components of the revenue requirements of all Texas utilities
- City of Blue Mound Condemnation of SWWC Water Utility- Valuation Assistance
- Assist with Analysis of Public Water Supply Divestiture in Louisiana
- Monarch Stock, Merger, Transfer (STM) Application Assistance

Crystal Clear WSC
Decertification analysis and valuation of the CCN for Texas GLO development area around New Braunfels Texas

Woodbine Development Corp.
Analysis and assistance with LCRA Windmill Ranch wholesale wastewater services contract renegotiations.

Canyon Lake Water Supply Company (San Jose Water)

- Valuation and Analysis of Clear Water Estates Acquisition for PUC STM Filing
- Valuation and Analysis of HEB Water and Wastewater Asset Divestiture
- Analysis and Forecast Regarding the Proposed Merger of Rebecca Creek Municipal Utility District
- Valuation of Bulverde Systems Purchased from Blanco River Authority

Aransas Bay Utilities Company, LLC
Valuation and Analysis of Water and Wastewater Assets for Proposed Divestiture.

Global Water Resources
Expert witness before American Arbitration Association regarding the financial standing and regulatory status of Global Water.

Corix Utilities
Assistance with due diligence, regulatory strategy analysis and bid preparation regarding the LCRA retail water and wastewater divestiture

Golden State Water Company
Assistance with analysis and bid concerning divestiture of SWWC Inc.

SUEZ Utilities

- Texas Regulatory Assessment of Water/Wastewater Utility Divestiture
- City of Scranton Wastewater Concession (Privatization) Due Diligence/Analysis

Other Water Related Engagements and Expert Proceedings-cont.

- City of O'Fallon, Illinois Water/Wastewater Concession (Privatization) Due Diligence/Analysis
- City of Rahway, New Jersey Concession Project (Privatization) Due Diligence/Analysis
- McKeesport Pennsylvania Concession (Privatization) Due Diligence/Analysis

Austin Apartment Association
Represented the Multi-Family water and wastewater classes in the City of Austin's Public Involvement Committee to review the 2017 water and wastewater rate study.

Greater Austin Water Forum
Assisted industrial class water users with analysis and participation in the City of Austin 2008 Cost of Service Study.

New Mexico Utilities
Review/analysis and critique report on Albuquerque Bernalillo County Water Utility Authority's Cost of Service Wholesale Wastewater Rate Model

Hays County Water Control & Improvement District No. 1 and No. 2
Developed 2015/2016 retail water and wastewater rate model, recommended retail water and wastewater rates and provided results and recommendations in a written report and presentation to the Boards of each utility.

PUBLIC UTILITY COMMISSION OF TEXAS

Project No. 21276

Modification of Rate Filing Package for Transmission Rates

TRANSMISSION COST OF SERVICE

RATE FILING PACKAGE
FOR
NON-INVESTOR OWNED TRANMISSION SERVICE PROVIDERS
IN THE ELECTRIC RELIABILITY COUNCIL OF TEXAS

(Non-IOU TCOS-RFP)
Pursuant to §25.192

As Adopted in December 16, 1999 Open Meeting

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GENERAL INSTRUCTIONS

The following instructions are applicable to all schedules required in the Transmission Cost of Service Rate Filing Package (TCOS-RFP) for non-investor owned transmission service providers (TSP) in ERCOT, unless otherwise noted.

1. Unless otherwise indicated, the information required in this filing will be taken from the accounts and records prescribed in the Federal Energy Regulatory Commission (FERC) chart of accounts or the chart of accounts as prescribed by the municipal governing body. All future references to "FERC" accounts in the TCOS RFP shall include the appropriate accounts of the municipal utility that are consistent with the FERC chart of accounts.

2. For the filing of the TCOS-FP, the following terms have the following meaning:
   a. Historic Year –Historic Year shall be the most recent fiscal year or calendar year. For the TSPs filing its TCOS application by May 15, 2000, the Historic Year can be the twelve month period ended September 30, 1999.
   b. Forecast Year –Forecast Year shall be the twelve-month period ended December 31, 2002 or the fiscal year ending in 2002.

   A TSP may use a 2002 forecasted test year only if it files its TCOS application by May 15, 2000 and only if it agrees to extend the effective date to January 1, 2002.

3. For the filing of the TCOS-RFP, the information reported shall be based on the Historic Year. The TSP shall use this Historic Year as the basis from which to forecast its transmission cost of service and billing determinants for the Forecast Year. All rate base items for the Forecast Year shall be reflected at their Forecast Year-end amounts. For the Forecast Year, expense items such as depreciation expense, operations and maintenance expense, taxes and return shall be based on forecasted amounts. Detailed supporting documentation shall be provided for all forecast adjustments.

4. For the Historic Year, costs shall be unbundled into the following three functions:
   a. Generation (GEN)
   b. Transmission (TRAN)
   c. Distribution (DIST)

   All references in these instructions to "the three functions" shall mean the three functions described in this paragraph (General Instruction No. 4) and the term "functionalize" shall mean the separation of costs into three functions. Of these functions, only the transmission will be projected for the Forecast Year.

5. A river authority, and one or more of its wholesale electric customers, may elect to file a combined transmission cost of service for the river authority and customer transmission cost of service requirements, that are not otherwise recoverable through transmission lease agreements with the river authorities allowed by PURA §35.007(b). The river

authority shall file information in sufficient detail to allow the commission to evaluate the reasonableness and prudence of the each customer's transmission cost of service.

6. A river authority shall be required to provide supplemental information and meet filing requirements in accordance with rules and procedures established by the PUC for securitization of stranded costs for river authorities at such time as such rules and procedures go into effect.

7. **Schedule referencing:** Schedules shall be referenced by schedule number and name as indicated in each instruction and shall identify the witness sponsoring the schedule. Schedules, which are not applicable, shall be so designated and include an explanation of why it is not applicable.

8. **Schedule format:** Schedules which require information by FERC account shall be in accordance with the following instructions:
Column (1): information as reported on the TSP's financial statements
Column (2): the adjustment necessary to remove non-regulated or non-electric amount from column (1) and items prohibited by statute or commission rule
Column (3): the electric information only (col.(1)-col.(2)+col.(3))
Column (4): the electric amount(s) transferred from one FERC account to another pursuant to General Instruction No. 9(b)
Column (5): Column (4) + Column (5)
Column (6): Allocation of the total in column (6) to Texas
Column (7): Allocation of column (6) to GEN function.
Column (8): Allocation of column (6) to TRAN function.
Column (9): Allocation of column (6) to DIST function.

Note 1: The TSP shall provide workpapers which detail the amounts transferred from one FERC account to another pursuant to General Instruction No. 9(b). Supporting calculations and the basis for each transferred item shall also be included in these workpapers.
Note 2: The TSP shall provide workpapers, which detail the allocations of column (6) to columns (7) through (9). These workpapers shall contain all supporting calculations and the basis for such allocations.
Note 3: Utilities shall provide workpapers which detail the affiliated items included and support the allocation methods used to derive the amounts included.
Note 4: These schedules attempt to provide a complete listing of accounts. However, if the TSP has accounts on its books not included in the schedule listing, those accounts should be added.

9. **Reclassification & Transfers:**
(a) Reclassifications between accounts shall be allowed consistent with commission rule. Reclassifications shall be documented in the appropriate schedules and amounts placed in the appropriate columns as generation, transmission or distribution. Reclassified costs should not be transferred from one account to

another and should not appear in column (4) referenced in General Instruction No. 8.

(b) Transfers shall only be used to make accounting adjustments in accordance with FERC accounting instructions.

10. **Adjustments:** Adjustments to historic period balances shall be made for the removal of items not allowed to be included in the TSPs cost of service by statute or Commission rule. Additionally, adjustments shall be made to the Historic Year to remove nonrecurring costs and normalize extraordinary expenditures. Workpapers detailing and explaining the adjustments made shall be provided.

11. **Functionalization:** Costs and rate base items shall be assigned to the three functions using the following three-step process and shall be consistent with PUCT Substantive Rule 25.192. No common costs will be assigned to regulated wholesale transmission function by default. If the TSP cannot meet its burden of proof, the costs in question will not be assigned to the wholesale transmission function.

a. For each FERC account, costs and rate base items shall be directly assigned to functions to the extent possible, and all relevant workpapers provided.

b. The TSP shall provide detailed workpapers documenting the nature of any costs or rate base items that cannot be directly assigned. For adequately documented items, the utility may derive an account-specific functionalization factor based on the directly assigned costs or appropriate cost-causation principles. The utility must justify the assignment of common costs to regulated functions, and must present evidence to support any such assignment.

c. If adequately documented costs or rate base items remain for which direct assignment or account-specific functionalization cannot be identified, the appropriate functionalization factor prescribed in Schedule F may be used. These functionalization factors shall only be used as a last resort. If a utility deems a functionalization factor other than the factor prescribed in Schedule F, to be necessary, the utility shall provide a detailed justification for the chosen functionalization factor.

After the Commission adopts this form, TSPs shall make reasonable changes in their cost accounting and or cost tracking system to ensure that costs are assigned directly to the cost objects and allocated based on the cost causation principles to the users and ensure that future cost information for the wholesale transmission function is collected in compliance with the three-step process described above and §25.192 on a forward going basis.

12. **Workpapers:** Concurrently with the filing of copies of the TCOS-RFP pursuant to Procedural Rule 22.71, the TSP must also separately file with the Commission corresponding complete sets of workpapers used in the preparation of certain schedules, subject to the provisions of General Instruction No. 15 dealing with voluminous workpapers. The TSP shall also concurrently file copies of its entire direct case, including all testimony and exhibits pursuant to Procedural Rule 22.71. In addition one complete set of the same TCOS-RFP, testimony, exhibits and workpapers shall be

delivered to the Office of Public Counsel on the date of filing. Upon request by any person moving to intervene (which request may be made prior to any anticipated rate filing), on the date of filing the TSP will furnish to such person one complete set of the same TCOS-RFP, testimony, exhibits and workpapers filed with the Commission.

a. Workpaper referencing format: The workpaper reference shall always begin with the characters "WP/" followed by the schedule to which the workpaper refers. Ascending numbers shall then reference specific workpapers. The resulting series of workpapers shall have a pyramid structure, with the top workpaper (the workpaper with the least complicated reference, for example WP/A-1) being the workpaper which directly reflects the amounts shown on a particular schedule (in this case, Schedule A-1). The next level down the pyramid (using the A-1 series, this would be WP/A-1/1) would contain information which explains a portion of the top workpaper (in this case, WP/A-1). Each successive level down the pyramid would explain something from the next higher level.

b. Workpaper content: All assumptions, calculations, sources, and data supporting allocation or functionalization of the historic period expenses and/or balances as well as the forecasted year expenses and/or balances shall be included in the workpaper supporting each schedule. Supporting documentation for each forecast adjustment shall be included in sufficient detail to allow parties to replicate the adjustment. In addition, specific numbers which "tie" between the schedule and the workpaper must be referenced on both the workpaper and the schedule.

c. Workpaper location: All workpapers not considered voluminous (See General Instruction No. 15, below) shall be organized and appear in the same order as the schedules they support.

13. **Electronic files:** To the maximum extent possible, the Non-IOU TCOS-RFP, testimony and schedules shall be also provided to all participants on diskette or CD-ROM format on the date of filing. Any numerical data provided electronically shall be in Microsoft Excel (preferred), Lotus Symphony, Lotus 1-2-3, or ASCII formats on MS-DOS formatted computer diskette or CD-ROM.

14. **Confidentiality:** If the TSP claims that requested information is confidential, a statement to that effect shall be included in the filing package in the schedule where the information is requested. All information requested in the schedule for which the TSP does not claim confidentiality shall be included in the filing package schedule. The TSP shall include as part of Schedule W a signed statement by its attorney that presents, for each schedule for which the TSP claims that the requested information is confidential, the claimed reasons that the information should be treated as confidential and that states that the attorney has reviewed the information sufficiently to state in good faith that the information is confidential.

Until a protective order is issued, the TSP shall provide ORA or a party granted intervenor status the information claimed to be confidential if the party agrees to be bound by the draft protective order contained in Schedule W as if it had been issued. Use of the draft protective order contained in Schedule W as a confidentiality agreement pending issuance of a protective order does not preclude issuance of a protective order that differs from the draft protective order contained in Schedule W.

15. **Voluminous material:** For any individual schedule or supporting workpaper that consists of 100 or more pages and is not available electronically, the company may designate such information as voluminous. All voluminous material shall be made available in a designated location in Austin on the date of filing. If the volume of the data meet the threshold for the "freight car doctrine" [eight (8) linear feet of document], the requested material shall be made available at its normal repository on the date of filing. The TSP shall provide a schedule detailing all normal repositories and cross-reference all TCOS-RFP schedules to the information contained in those repositories. For the purpose of General Instruction No. 15, each subpart of each section is a separate schedule (e.g., Schedule A-1, B-1, C-1, etc., are all separate schedules). The TSP shall deliver a hard copy of all voluminous materials not subject to the "freight car doctrine" to both the Office of Regulatory Affairs/Legal Division and the Office of Public Utility Counsel on the day of filing the TCOS-RFP application.

16. **Attached forms:** Certain schedule titles are followed by "(see attached form)." Where such a notation appears, the format for the schedule is provided and is to be followed.

DEFINITION OF TERMS AND ACRONYMS

A&G	Administrative and General
ADIT	Accumulated Deferred Income Tax
CWIP	Construction Work In Progress
DSC	Debt Service Coverage
EPHFU	Electric Plant Held For Future Use
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
IOU	Investor-Owned utility
M & S	Materials & Supplies
O & M	Operations & Maintenance
ORA	Office of Regulatory Affairs
PUC/PUCT	Public Utility Commission of Texas
PURA	Public Utility Regulatory Act
ROR	Rate of Return
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SOAH	State Office of Administrative Hearings
TCOS	Transmission Cost of Service
TCOS-FP	Transmission Cost of Service Filing Package
TIER	Times Interest Earned Ratio
TSP	Transmission Service Provider
4-CP	Average of Four Coincident Peak

SECTION I :
HISTORIC YEAR DATA

Schedule A: Summary of Total Cost of Service by Function (See Attached Form)

This schedule shall summarize the TSP's overall cost of service functionalized for the Historic Year including but not limited to, non-fuel operations and maintenance expenses, eligible fuel and purchased power expenses (if applicable[1]), non-eligible fuel and purchased power expense (if applicable), depreciation expenses, federal income taxes if applicable, taxes other than income taxes, and the return or coverage developed from the supporting schedules described herein. For any expenses in eligible or non-eligible fuel and purchased power expenses that are not included in generation costs, the FERC account for this expense and an explanation of why this expense is not included in the Generation function shall be included. Presentation shall be such that amounts can be readily determined and all costs to be included in TCOS shall be referenced to the detailed schedules B through E and/or the appropriate workpapers, computations, and analyses. This schedule should also show the derivation of the new wholesale transmission rate calculated by dividing the total transmission revenue requirement by the most recent total system ERCOT 4-CP at the time of application.

[1] Municipally Owned Utilities and TSPs without generation do not have to distinguish between eligible and ineligible fuel and purchased power costs. These entities shall report their total fuel cost and total purchased power cost.

SCHEDULE B: RATE BASE

Schedule B: Summary of Rate Base by Function (See Attached Form)

The schedule shall summarize the TSP's overall rate base as of end of the Historic Year, separated into three functions. Presentation shall be such that amounts can be readily determined and all items included shall be referenced to the detailed schedules and/or the appropriate workpapers, computations, and analyses. Supporting information may include one-line diagrams (marked to identify transmission, distribution and common facilities) of all distribution substations for which the high side (transmission voltage related equipment) is included in transmission rate base, functionalization factors or other documentation necessary to support the separation of rate base items (including "common" facilities) into the three functions.

Schedule B-1: Original Cost of Plant

This schedule shall summarize the amounts of plant by FERC accounts 301-388 of the Uniform System of Accounts as of the end of the Historic Year, functionalized pursuant to General Instruction No 11. Utilities may reclassify some amounts among functions, consistent with Commission's Substantive Rule 25.192(b). Any reclassification of plant shall be made in accordance with General Instruction No. 9. This schedule shall tie to the book balances at the end of the Historic Year. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule B-2: General Plant Functionalization

This schedule shall detail the amounts of general plant for the Historic Year by FERC accounts 389-399, functionalized pursuant to General Instruction No. 11. Supporting workpapers that fully and clearly explain the functionalization of each account or sub account shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule B-3: Communication Equipment

This schedule shall show the balance of communication equipment for the Historic year in FERC Account 397, or other account (specify) where such equipment is booked, functionalized pursuant to General Instruction No. 11. For the purposes of General Instruction No. 11, equipment located at substations, which provide multiple functions, shall be functionalized on the same basis as common plant at that substation. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule B-4: Unbundled Construction Work in Progress

This schedule shall show the amount of Construction Work in Progress (CWIP) directly for the Historic Year, functionalized pursuant to General Instruction No. 11. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule B-5: Unbundled Accumulated Depreciation

This schedule shall include the accumulated provisions for depreciation detailed by primary account classification (e.g., 350-359, 360-373, 389, etc.) as of the end of the Historic Year, functionalized pursuant to General Instruction No. 11. A description of the methods and procedures followed in booking depreciation shall be included in this schedule. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F. All depreciation rates and methodologies shall be included by primary account classification.

Schedule B-6: Unbundled Plant Held for Future Use

This schedule shall show the amount of Electric Plant Held for Future Use (EPHFU) as of the end of the Historic Year functionalized pursuant to General Instruction No. 11. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule B-7: Unbundled Accumulated Provision Balances

This schedule shall show the ending balance (Historic Year) of each accumulated provision account (i.e., injuries and damages, property insurance, etc.) functionalized pursuant to General Instruction No. 11. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule B-8: Unbundled Materials and Supplies

This schedule shall show the total amount of Materials and Supplies (M&S) as of the end of the Historic Year functionalized pursuant to General Instruction No. 11. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule B-9: Unbundled Cash Working Capital

This schedule shall show the amount of Cash Working Capital included in each component of the unbundled rate base as of the end of the Historic Year, functionalized on the same basis as the underlying expense, and consistent with General Instruction No. 11. The amount to be included will be in accordance with P.U.C Subst. R. 25.231(c)(2)(B)(iii). Municipal utilities,cooperatives, and river authorities shall be allowed to use the one-eighth method to calculate cash working capital allowance. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule B-10: Unbundled Prepayments

This schedule shall show the amount of Prepayments as of the end of the Historic Year, functionalized on the same basis as the underlying expense, and consistent with General Instruction No. 11. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule B-11: Unbundled Other Rate Base Items

This schedule shall detail all other rate base items for the Historic Year not included in the previous categories, functionalized pursuant to General Instruction No. 11. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section and any functionalization factors shall be referenced to the appropriate factors in Schedule F. Supporting workpapers showing the derivation of the amounts shall also be included.

Schedule B-12: Unbundled Regulatory Assets (See Attached Form)

The TSP shall provide the total amount of regulatory assets detailed on asset-by-asset basis for the Historic Year, functionalized pursuant to the General Instruction No. 11. For each item that the TSP claims as regulatory asset, the TSP should identify with specificity the commission Order (including applicable pages) or other authority upon which it bases it claims. If the TSP relies upon an authority other than a commission Order as the basis of its claim, it should provide a copy of the document(s) it relies on. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

SCHEDULE C: RATE OF RETURN, DEBT SERVICE COVERAGE, CASH FLOW, OR TIMES INTEREST EARNED RATIO

The determination of final revenue requirements for a municipal utility, river authority, power agency, or electric cooperative may be based on any of the following methods at the election of the filing TSP.

Schedule C-1: Rate of Return Method

The rate of return may be the TSP's weighted average cost of capital based upon the TSP's capitalization at the end of the Historic Year. A schedule showing the calculation shall be provided. The cost of debt capital and owner's equity shall be the weighted average cost as of the end of the Historic Year. A cost of owner's equity equal to the average yield for bonds of an entity with the TSP's credit rating published in Moody's Credit Perspective or similar publication during the most recent three months plus two percent shall be presumed reasonable. The TSP shall justify the use of any other rate of return, and shall specify the special circumstances that warrant the use of a different rate of return. Supporting documentation shall be provided for the average bond yields used in the cost of equity calculation.

Description Of Schedules:
A schedule showing the calculation of the TSP's weighted average cost of capital shall be provided

Schedule C-2: Debt Service Coverage (DSC) Method:

A return based on the TSP's debt service expenses as of the end of the Historic Year, and the debt service coverage levels stated in the TSP's most recently issued bond and debt covenants plus additional coverage of 0.25 for municipal utilities and river authorities shall be presumed reasonable. To the extent the utility can show that short-term debt has been utilized in a cost-effective manner as a reasonable alternative to long-term financing, its principal and interest and an additional coverage of 0.25 may be included in calculating the return. The return for short-term debt shall not include the coverage that is specified in the bond and debt covenants unless the covenants include short-term debt service in the denominator of the DSC ratio that is used to calculate default on the debt. To the extent there are no minimum debt service coverage requirements in the TSP's bond resolutions, the Board of Director's policy, with respect to coverage, shall be considered. At the option of the TSP, the return or debt service coverage approved by a municipality's or a river authority's ratemaking authority, within three years of the TCOS, filing may be used. The TSP shall justify the use of any other debt service coverage, and shall specify the reasonable circumstances that support the use of different debt service coverage.

The Texas Municipal Power Agency or its successor in interest may, at its option, use the rate of return method for calculating its transmission cost of service. If the rate of return method is used, the return component for the transmission cost of service revenue requirement shall be sufficient to meet the transmission function's pro rata share of levelized debt service and debt service coverage ratio (1.50) and other annual debt obligations; provided, however, that the total levelized debt service may not exceed the total debt service under the current payment schedule.

Any additional revenue generated by the methodology described in this subsection shall be applied to reduce the agency's outstanding indebtedness.

An electric cooperative may, at its option, use the debt service coverage method for calculating its transmission cost of service. The debt service coverage levels stated in the cooperative’s most recent debt covenants plus additional coverage of 0.50 shall be presumed reasonable. To the extent that short-term debt is included in the calculation of these debt service coverage level covenants, it may be included in the debt service coverage used to calculate the transmission cost of service. To the extent there are no minimum debt service coverage requirements in the cooperative’s debt covenants, the Board of Director’s policy, with respect to coverage, shall be considered. At the option of the TSP, debt service coverage, based on rates approved by a cooperative’s ratemaking authority, within three years of the TCOS filing may be used. The cooperative shall justify the use of any other debt service coverage, and shall specify the reasonable circumstances that support the use of different debt service coverage.

Description of Schedules:

a. For utilities using the debt service coverage method, a schedule showing the debt service requirement for each debt issue outstanding at the end of the fiscal year shall be provided, as well as relevant excerpts of the bond and debt covenants supporting the debt service coverage utilized.
b. An additional schedule showing the calculation of return and rate of return on invested capital in total plant (rate base) shall be provided. Return is computed based on the amount of debt service requirements (net of capitalized interest) times the coverage ratio described above, less interest income and depreciation. Supporting fiscal or calendar year-end audited financial statements (if available) and any other documents necessary to support the TSP’s debt service requirement and other components in the return calculation, including the sources of interest income, shall be provided. In addition, the following financial ratios shall be provided, based on the requested debt service coverage ratio: *revenues per kWh; and net income per revenue dollar*. The percentage of revenues from generation and the percentage of revenues from distribution should be provided if unbundled, and if not unbundled, then generation and distribution revenues should be provided on a bundled basis. If the TSP has any unique characteristics, which might have a bearing on return, it should provide a narrative describing the characteristics.

Schedule C-3: Cash Flow Method

A TSP may elect to use the cash flow method for determining its transmission revenue requirement based on the Historic Year. If the TSP elects to use the cash flow method, the Commission shall consider reasonable cash needs in to the following categories:

A debt service (including principal and interest) for long- term and short-term debt;

B funding of reserve requirements on both long-term and short-term debt as set forth in revenue bond and debt ordinances;

C for municipal utilities, annual payments for transfers to the city’s general fund at rates established by the municipal utility’s governing authority, to the extent such amounts are not recovered through other elements of the TCOS.

D capital lease payments and/or finance lease payments;

E annual payments to provide internally generated funds for construction, system improvements, and repair and replacement;

Transfers to the general fund (which may have different names in different municipal utility systems), debt service, and funding of reserve requirements shall be functionalized, subject to commission review, to the transmission function on a basis comparable to that used to allocate such costs to the other functions of the municipal utility.

Lease payments and capital expenditures shall be included to the extent the can be directly assigned to the wholesale transmission function.

Transmission related costs other than the elements described above should be determined in accordance with the appropriate instructions contained in these rate-filing package.

Description of Schedules:

For utilities using the Cash Flow Method, a schedule showing the costs to be included shall be provided together with supporting documentation in the form of bond and debt covenants, adopted policies of the governing authority, approved budgets and other documentation supporting the Cash Flow Component as may be reasonably required by the Commission.

Schedule C-4: Times Interest Earned Method:

Generation and Transmission Cooperatives

Generation and Transmission Cooperatives may use a rate of return based on the TSP's interest expense requirement on long term debt outstanding as of the end of the Historic Year, and a net times-interest-earned ratio (Net TIER) of 1.05 plus additional coverage of 0.15 times shall be presumed reasonable. At the option of the TSP, the rate of return most recently approved by its governing body may be used if the rates were approved within three years of the TCOS filing. The TSP shall justify the use of any other rate of return, and specify the special circumstances that warrant the use of a different rate of return. Special circumstances for purposes of this subsection may include a showing of an equity ratio below 20 percent, or a showing that the proposed Net TIER is insufficient to meet the reasonable cash needs (particularly debt service and internal funds for transmission plant additions) of the TSP.

Description of Schedules:

a) A schedule showing the interest expense requirement for each long-term debt issue outstanding at the end of the Historic Year shall be provided.
b) An additional schedule showing the calculation of return and rate of return on invested capital in total plant (rate base) shall be provided. Return is computed based on the amount of interest expense requirement at the end of the year times the 1.20 times Net TIER, less non-operating margins, plus other interest expense and other deductions. Supporting year-end financial statements and any other documents necessary to support the debt outstanding at year-end and the calculation of return, including the sources of non-operating margins, shall be provided.

Electric Distribution Cooperatives

An electric distribution cooperative may use a rate of return based on the TSP's interest expense on long term debt outstanding at the end of the Historic Year, and a modified times interest earned ratio excluding capital credits (modified TIER) of 2.0 times shall be presumed reasonable. The TSP shall justify the use of any other rate of return, and shall specify the special circumstance that warrants use of a different rate of return.

Description of Schedules:

a) A schedule showing the interest expense requirement for each debt issue outstanding at the end of Historic Year shall be provided.
b) An additional schedule calculating return and rate of return on invested capital in total plant (rate base) shall be provided. Return is computed based on the amount of interest expense requirement at year end times the 2.0 times modified TIER, less non-operating income other than capital credits, plus other interest expense and other deductions. Supporting year-end financial statements and any other documents necessary to support the debt outstanding at year-end and the calculation of return, including the sources of non-operating income, shall be provided.

Municipal Utilities or River Authorities

Municipal Utilities or River Authorities electing to use the TIER method will be considered on a case-by-case basis.

SCHEDULE D: OPERATION & MAINTENANCE EXPENSES

Schedule D-1: O&M Expenses

This schedule shall include the TSP's overall operations and maintenance expenses according to FERC accounts 500-917 for the Historic Year, functionalized pursuant to General Instruction No. 11. The documentation shall itemize the wheeling expenses incurred for the old contracts on a contract by contract basis. Utilities may reclassify some amounts among functions, consistent with Commission's Substantive Rule 25.192(b). Any reclassification of expenses shall be made in accordance with General Instruction No. 9. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule D-2: A&G Expenses

This schedule shall show the annual expenses in FERC accounts 920-935 for the Historic Year, functionalized pursuant to General Instruction No. 11. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

<u>Schedule D-3: Payroll Expense Distribution</u>

This schedule shall present the payroll expense for the Historic Year by FERC primary account functionalized pursuant to General Instruction No. 11. For the purpose of General Instruction No. 11, Payroll Expenses shall be functionalized using the same factors as the respective accounts in the O&M schedules. For accounts, which are functionalized using a composite factor, the respective composite factors shall be developed based on Payroll information only. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

<u>Schedule D-5: Summary of Exclusions from Reporting Period (See Attached Form)</u>

This schedule shall present a summary of all reporting period expenditures for items not allowed to be included in the TSP's cost of service by statute or commission rule.

SCHEDULE E: OTHER ITEMS

Schedule E-1: Depreciation Expense

This schedule shall show the TSP's overall unbundled depreciation expense for the Historic Year for the TSP's plants and shall be based on Commission approved depreciation rates or an updated depreciation study. If a TSP does not have Commission approved depreciation rates, the TSP shall provide the basis for the depreciation rates used and explain the process by which the rates were established. Documentation supporting the approval of the depreciation rates used shall be provided. Plant depreciation rates and depreciation expense shall be shown by FERC Account, functionalized pursuant to General Instruction No. 11. All adjustments appearing on this schedule shall be referenced to detailed workpapers, computations, and analyses. Presentation shall be such that amounts can be readily determined and all costs to be included in each function shall be referenced to the detailed schedules and/or the appropriate workpapers, computations and analyses. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule E-2: Taxes Other Than Federal Income Taxes

This schedule shall show the amount of other taxes, excluding federal income taxes, assessed on or paid for by the TSP for the Historic Year, functionalized pursuant to General Instruction No. 11. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F. To the extent that PURA identifies the functionally separated business entities of the TSP that are responsible for payment of specific revenue related taxes, these taxes will be directly assigned to these entities in accordance with the statute.

Schedule E-3: Federal Income Tax

Federal Income Taxes shall be calculated using the return method for the Historic Year, functionalized pursuant to General Instruction 11. Supporting explanations and calculations shall be referenced to this schedule, and if not found elsewhere in the TCOS-RFP, shall be provided as workpapers to this schedule. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule E-4: Other Expenses

This schedule shall show all items not classified elsewhere, functionalized on the same basis as the underlying expense and consistent with General Instruction No. 11. All items shall be identified on an item by item basis and supporting workpapers shall be provided. Supporting workpapers that fully and clearly explain the functionalization of each account or subaccount shall be included in the workpaper section, and any functionalization factors shall be referenced to the appropriate factors in Schedule F.

Schedule E-5: Other Revenue Items (credit)

This schedule shall show all other revenue credits functionalized on the same basis as the underlying assets or activities and consistent with General Instruction No. 11. Wheeling revenues shall not be credited to Transmission function. Revenues from transmission of electric energy out of ERCOT over DC ties that is not recovered through rates for annual planned transmission service and revenue from monthly, weekly, and daily planned transmission service, however, shall be credited to Transmission. Supporting documentation shall be provided. The portion of the revenue credits functionalized to transmission function shall be deducted from the TSP's total cost of service for transmission.

Schedule E-6: Wheeling Revenue under Existing Contracts

This schedule shall detail the amount of wheeling revenues received under existing contracts on contract by contract basis.

SCHEDULE F: FUNCTIONALIZATION FACTORS

1. Provide a listing of functionalization factors and associated data, which shall include the following information for every factor, used to assign costs to a function:
   a. A narrative description of the functionalization factor if code designation is used.
   b. The relative (decimal representations of percentages) amounts constituting the functionalization factors.
   c. The absolute amounts constituting the factors. That is the data used as numerators and divisors in calculating the functionalization factors in b. above.

2. Provide workpapers and a narrative explanation to support the calculation of each functionalization factor listed in 1 above. To the extent that data provided elsewhere in this filing package are employed in directly developing the functionalization factors, workpapers shall be referenced directly to this data.

3. For direct assignment (General Instruction No. 11(a)) and account-specific assignment (General Instruction No. 11(b)) of costs, provide a narrative description of the justification for such assignment.

The following table lists factors, which may be used to functionalize costs pursuant to General Instruction No. 11 (c). For FERC accounts, which do not appear in this table, it is assumed that all costs will be functionalized pursuant to General Instruction Nos. 11(a) and 11(b).
This table is for reference and summary purposes only. Specific instructions given elsewhere in this rate-filing package control over any summary information presented in this table.

FERC Acct.	TITLE	SUBACCOUNT	ALLOCATOR
301	Organization	Revenue-Related Items	TOTREV
301	Organization	Plant-Related Items	PLTSVC-NX
302	Franchise and Consents	Revenue-Related Items	TOTREV
302	Franchise and Consents	Plant-Related Items	PLTSVC-NX
303	Misc. Intangible Plant	Revenue-Related Items	TOTREV
303	Misc. Intangible Plant	Plant-Related Items	PLTSVC-NX
310-346	Generation Plant		GEN (re-classify GEN/TRAN per 25.192 (b))
350-359	Transmission Plant		TRAN (re-classify TRAN/GEN or TRAN/DIST per 25.192 (b))
360-373	Distribution Plant		DIST (re-classify DIST/TRAN per 25.192(b))
389	Land and Land Rights		SQFT
390	Structures and Improvements		SQFT

391	Office Furniture and Equipment		SQFT
392	Transportation Equipment		MILE
393	Stores Equipment		PLTXGNL-N
394	Tools, Shop and Garage Equipment		PLTXGNL-N
395	Laboratory Equipment		PLTXGNL-N
396	Power Operated Equipment		PLTXGNL-N
397	Communication Equipment		Schedule B-5
398	Misc. Equipment		PLTXGNL-N
500-554	GEN O&M		GEN
555	Purchased Power	Wholesale	GEN/TRAN based on supplier info
555	Purchased Power	Cogenerator	GEN
555	Purchased Power	Economy Energy	GEN (TRAN for losses)
556	System Control and Load Dispatching		GEN/TRAN - direct assignment
557	Other Expenses		GEN
560-564, 566-574	Transmission O&M		TRAN
565	Wheeling Expenses (ERCOT)		DIST
580-598	Distribution O&M		DIST
901	Supervision		DIST
902	Meter Reading Expense		DIST
903.E	Customer Records and Collection Expenses	Collection Expenses	DIST
903.R	Customer Records and Collection Expenses	Customer Records	DIST
905	Misc. Customer Account Exp.		DIST
907-917	Customer Service & Information,Sales		DIST
920	A&G Salaries		PAYXAG
921	Office Supplies		PAYXAG
922	Admin. Expenses Transferred		PAYXAG
923	Outside Services		TOMXFP
924	Property Insurance Expense		PLTSVC-N
925	Injuries and Damages		PAYXAG
926	Pensions and Benefits		PAYXAG
927	Franchise Requirements		DIST
928	Regulatory Expenses		TOTREV (PUC assessment DIST)

930	Misc. General Expense	Plant-related	PLTSVC-N
930	Misc. General Expense	Personnel-related	PAYXAG
931	Rents		PAYXAG
935	Maint. Of General Plant		GNLPLT-N

Where a one or more of the three functions is listed in the Functionalization Factor column, the costs in that FERC account shall be assigned exclusively to the function(s) listed. The remaining functionalization factors in the above table are defined as follows:

C902_3	Composite allocator, comprised of FERC accounts 902 and 903
PAYROLL	Total Payroll
PAYXAG	Payroll, excluding Administrative and General Salaries and excluding Contract Labor
PAYXAGIC	Payroll excluding Administrative and General Salaries and including Contract Labor
PLTXGNL-N	Net Plant, excluding General Plant
PLTSVC-N	Net Plant in Service
PLTSVC-NX	Net Plant in Service, excluding Intangible Plant
SQFT	Building Square Footage allocator (Assume Human Resources (HR) occupies one tenth of the total office space, therefore one tenth of total expense and rate base items for which square feet is an appropriate cost driver such as furniture, heating etc. will be allocated to the HR cost center, later HR costs will be allocated based on payroll or number of employees (appropriate cost drivers for HR functions) to the user of the HR services.)
TOMXFP	Total Operations and Maintenance Expenses, excluding Fuel and Purchased Power
TOTREV	Total Revenue
TRB	Total Rate Base
MILE	Miles driven on the transportation equipment

SECTION II:
FORECAST YEAR DATA

Schedule A(f): Summary of Transmission Cost of Service (See Attached Form)

This schedule shall provide the TSP's Forecast Year unbundled cost of service for the transmission function. It shall begin with the Historic Year cost of service for this function as reported on Schedule A-1. An additional column shall present the forecast adjustments to the Historic Year which are necessary to reach the Forecast Year. All adjustments appearing on this schedule shall be referenced to detailed workpapers, computations, and analyses. Presentation shall be such that amounts can be readily determined and all costs to be included in each function shall be referenced to the detailed schedules B(f) through E(f) and/or the appropriate workpapers, computations and analyses.

SCHEDULE B(f): RATE BASE

Schedule B(f): Summary of Transmission Rate Base (See Attached Form)

This schedule shall provide the TSP's forecasted transmission rate base. It shall begin with the Historic Year rate base as reported on Schedule B for the transmission function. An additional column shall present the forecast adjustments to the Historic Year, which are necessary to reach the Forecast Year. Only plant in service projected to be in service at December 31, 2002 shall be allowed. All adjustments appearing on this schedule shall be referenced to detailed workpapers, computations, and analyses. Presentation shall be such that amounts can be readily determined and all costs to be included in each function shall be referenced to the detailed schedules B(f)-1 and B(f)-12 and/or the appropriate workpapers, computations and analyses.

Schedule B(f)-1: Original Cost of Transmission Plant

This schedule shall provide, by FERC account, the TSP's estimated plant balances as of the end of the Forecast Year for the transmission function. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-1. An additional column shall present forecast adjustments to the historic balances necessary to reach the plant balances expected to be in service at the end of the Forecast Year. Only plant in service projected to be in service at the end of the Forecast Year shall be allowed. All adjustments appearing on this schedule shall be referenced to detailed workpapers, computations, and analyses. Presentation shall be such that amounts can be readily determined and all costs to be included in each function shall be referenced to the detailed schedules and/or the appropriate workpapers, computations and analyses.

Schedule B(f)-2: General Plant Functionalized to Transmission

This schedule shall detail the amounts of general plant for the Forecast Year functionalized to transmission by FERC accounts 389-399. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-2. An additional column shall present forecast adjustments to the historic balances necessary to reach the plant balances expected to be in service at the end of the Forecast Year. Supporting workpapers that fully and clearly explain the forecast adjustments to each account shall be included in the workpaper section.

Schedule B(f)-3: Communication Equipment in Transmission

This schedule shall show the balance of communication equipment for the Forecast Year in FERC Account 397, or other account (specify) where such equipment is booked as reported on Schedules B(f)-1 and B(f)-2 and as functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-3. An additional column shall present forecast adjustments to the historic balances necessary to reach the plant balances expected to be in service at the end of the Forecast Year. Supporting workpapers that fully and clearly explain the forecast adjustments to each account shall be included in the workpaper section.

Schedule B(f)-4.: Unbundled Construction Work in Progress in Transmission

This schedule shall detail the amounts of construction work in progress for the Forecast Year functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-4. An additional column shall present forecast adjustments to the historic balances necessary to reach the plant balances expected to be in service at the end of the Forecast Year. Supporting workpapers that fully and clearly explain the forecast adjustments to each account shall be included in the workpaper section.

Schedule B(f)-5: Unbundled Accumulated Depreciation in Transmission

This schedule shall detail the accumulated provisions for depreciation by primary account classification (e.g., 350-359, 360-373, 389, etc.) for the Forecast Year that is functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-5. An additional column shall present forecast adjustments to the historic balances necessary to reach the account balances expected at the end of the Forecast Year. Supporting workpapers that fully and clearly explain the forecast adjustments to each account shall be included in the workpaper section.

Schedule B(f)-6: Unbundled Plant Held for Future Use in Transmission

This schedule shall show the amount of Electric Plant Held for Future Use (EPHFU) as of the end of the Forecast Year and as functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-6. Additional columns shall present forecast adjustments to the historic balances necessary to reach the plant balances expected to be in service at the end of the Forecast Year. Supporting workpapers that fully and clearly explain the forecast adjustments to each account shall be included in the workpaper section.

Schedule B(f)-7: Unbundled Accumulated Provision Balances in Transmission

This schedule shall show the ending balance (Forecast Year) of each accumulated provision account (i.e., injuries and damages, property insurance, etc.) as functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-7. An additional column shall present forecast adjustments to the historic balances necessary to reach the account balances expected at the end of the Forecast Year. Supporting workpapers that fully and clearly explain the forecast adjustments to the total amounts shall be included in the workpaper section.

Schedule B(f)-8: Materials and Supplies in Transmission

This schedule shall show the total amount of Materials and Supplies (M&S) as of the end of the Forecast Year and as functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-8. An additional column shall present forecast adjustments to the historic balances necessary to reach the account balances expected to be in service at the end of the Forecast Year. Supporting workpapers that fully and clearly explain the forecast adjustments to the total amount shall be included in the workpaper section.

Schedule B(f)-9: Cash Working Capital in Transmission

This schedule shall show the total amount of Cash Working Capital included in transmission rate base as of the end of the Forecast Year. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-9. An additional column shall present forecast adjustments to the historic balances necessary to reach the balances expected at the end of the Forecast Year. The amount to be included will be in accordance with PUC Substantive Rule 25.231(c)(2)(B)(iii). Supporting workpapers that fully and clearly explain the forecast adjustments to the total shall be included in the workpaper section.

Schedule B(f)-10: Prepayments in Transmission

This schedule shall show the amount of Prepayments as of the end of the Forecast Year and as functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-10. An additional column shall present forecast adjustments to the historic balances necessary to reach the account balances expected at the end of the Forecast Year. Supporting workpapers that fully and clearly explain the forecast adjustments to the total shall be included in the workpaper section.

Schedule B(f)-11: Other Rate Base Items in Transmission

This schedule shall detail all other rate base items for the Forecast Year not included in the previous categories that are functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-11. An additional column shall present forecast adjustments to the historic balances necessary to reach the plant balances expected to be in service at the end of the Forecast Year. Supporting workpapers shall be included showing the derivation of the amounts included.

Schedule B(f)-12: Regulatory Assets (See Attached Form)

The TSP shall provide the total amount of regulatory assets detail on an asset-by-asset basis for the Forecast Year as functionalized to the transmission function. It shall begin with the corresponding Historic Year-end balances presented on Schedule B-12. An additional column shall present forecast adjustments to the historic balances necessary to reach the asset balances expected at the end of the Forecast Year. Supporting workpapers that fully and clearly explain the forecast adjustments to the total shall be included in the workpaper section.

SCHEDULE C(f): RATE OF RETURN, DEBT SERVICE COVERAGE, CASH FLOW, OR TIMES INTEREST EARNED RATIO

Schedule C(f)-1: Rate of Return Method::
For utilities electing to make a transmission cost of service filing using a Forecast Year, a forecast showing the calculation of the TSP's weighted average cost of capital shall be provided.

Schedule C(f)-2: Debt Service Coverage Method:
For utilities required or electing to make a transmission cost of service filing on a Forecast Year, a forecast debt service coverage shall be used and supported with an appropriate schedule.

Schedule C(f)-3: Cash Flow Method:
For utilities required or electing to make a transmission cost of service filing on a Forecast Year, a forecast cash flow shall be used and supported with an appropriate schedule.

Schedule C(f)-4: Times Interest Earned Method:
For utilities required or electing to make a transmission cost of service filing on a Forecast Year, a forecast times interest earned shall be used and supported with an appropriate schedule.

<u>SCHEDULE D(f): OPERATION & MAINTENANCE EXPENSES</u>

<u>Schedule D(f)-1: Transmission O&M Expenses</u>

This schedule shall include the TSP's overall operations and maintenance expenses according to FERC accounts 500 – 917 for the Forecast Year as functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule D-1. An additional column shall present forecast adjustments to the historic balances necessary to reach the Forecast Year expenses. Supporting workpapers that fully and clearly explain the forecast adjustments to the total shall be included in the workpaper section. Presentation shall be such that amounts can be readily determined and all costs to be included in each function shall be referenced to the detailed schedules and/or the appropriate workpapers, computations, and analyses.

<u>Schedule D(f)-2: A&G Expenses in Transmission</u>

This schedule shall show the annual expenses in FERC accounts 920-935 for the Forecast Year and as functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule D-3.1. An additional column shall present forecast adjustments to the historic expenses necessary to reach the Forecast Year expenses. Supporting workpapers that fully and clearly explain the forecast adjustments to the total amounts shall be included in the workpaper section.

SCHEDULE E(f): OTHER ITEMS

Schedule E(f)-1: Transmission Depreciation Expense

This schedule shall show the TSP's overall depreciation expense for plants functionalized to transmission for the Forecast Year and shall be based on Commission-approved depreciation rates. If a TSP does not have Commission approved depreciation rates, the TSP shall provide the basis for the depreciation rates used and explain the process by which the rates were established. Documentation supporting the approval of the depreciation rates used shall be provided. Plant depreciation rates and functionally unbundled depreciation expense shall be shown by FERC Account. To calculate the unbundled depreciation expense for the Forecast Year, the TSP shall begin with the Historic Year expense for transmission function. An additional column shall present the forecast adjustments to the Historic Year which are necessary to reach the Forecast Year. Only plant in service projected to be in service at December 31, 2002 shall be allowed. All adjustments appearing on this schedule shall be referenced to detailed workpapers, computations, and analyses. Presentation shall be such that amounts can be readily determined and all costs to be included in each function shall be referenced to the detailed schedules and/or the appropriate workpapers, computations and analyses.

Schedule E(f)-2: Taxes Other Than Federal Income Taxes in Transmission

This schedule shall show the amount of other taxes, excluding federal income taxes, for the Forecast Year functionalized to transmission. It shall begin with the corresponding Historic Year-end balances presented on Schedule E(f)-2. An additional column shall present forecast adjustments to the historic expenses necessary to reach the Forecast Year expenses.

Schedule E(f)-3: Federal Income Taxes

Federal Income Taxes will be calculated using the return method for the Forecast Year. Supporting explanations and calculations shall be referenced to this schedule, and if not found elsewhere in the TCOS-RFP, shall be provided as workpapers to this schedule. It shall begin with the corresponding Historic Year expenses presented on the corresponding Historic Year schedule. Additional columns shall present forecast adjustments to the historic expenses necessary to reach the Forecast Year expenses.

Schedule E(f)-4: Other Expenses in Transmission

This schedule shall show all items not classified elsewhere and functionalized to transmission. All items shall be identified on an item by item basis and supporting workpapers shall be provided. It shall begin with the corresponding Historic Year-end balances presented on Schedule E-4. An additional column shall present forecast adjustments to the historic expenses necessary to reach the Forecast year expenses.

Schedule E(f)-5: Other Revenue Items (credit) in Transmission

Other revenue credits shall be directly assigned or itemized and functionalized in this schedule. Supporting documentation shall be provided. It shall begin with the corresponding Historic Year-end balances presented on Schedule E-5. Additional columns shall present forecast adjustments to the historic expenses necessary to reach the Forecast Year revenues. Wheeling revenues shall not be credited to Transmission function. TSP’s share of the total ERCOT wide revenues (based on the ERCOT wide ISO forecast) from transmission of electric energy out of ERCOT over DC ties and revenue from monthly, weekly, and daily planned transmission service, that is not recovered through rates for annual planned transmission service however, shall be credited to Transmission revenue requirement of the TSP.

SECTION III
AFFILIATE DATA

General Instructions

1. The affiliate filing requirements apply to TSPs in ERCOT having affiliates that have provided services or property the value of which is included in one of the three functions.
2. The definition of transmission costs for purposes of this filing shall be coordinated and consistent with the definition of these costs in Commission Substantive Rule 25.341. Appropriate consideration should be given to the guidance provided by FERC through its account classification and functional descriptions.
3. For purposes of this filing, transmission costs shall include transmission–related, *e.g.*, transmission–related administrative and general (A&G) costs in support of Texas activities.
4. The term "per book" is the Historic Year without pro-forma adjustments.
5. The term "net requested" amount for an item is the Historic Year with pro-forma adjustments to the Forecast Year and represents the revenue requirement on which the revised transmission rates are to be set.

Guiding Principles

1. To the extent that the affiliate standard prescribed by §36.058 of PURA is applicable in this filing, it should only be applied to the transmission function. However, in order to satisfy the requirements of §36.058, the Commission and other parties will be provided the affiliate costs charged to the three functions as well as to the other affiliates.

2. Transmission costs shall be presented in sufficient detail (*e.g.*, transmission operations, transmission maintenance, FERC accounts 560 – 562, FERC accounts 568-574, or other logical groupings of services) to permit the Commission to conduct the review as required by PURA §36.058.

3. The following are examples of the types of evidence that may be presented to support the applicant's burden of proof for the recovery of affiliate costs:
   a. historical cost trends;
   b. process improvements aimed at achieving efficiency;
   c. benchmark data. It is acknowledged that benchmark comparisons may not be available for all transmission costs. To the extent that certain relevant costs are not included in the benchmark data used for comparison purposes, other evidence may be provided to address those costs. d. outsourcing results;
   e. proof of customer benefit;
   f. a showing that services are not duplicated at the TSP;
   g. comparison of Historic Year costs to costs that would be expected if the TSP were a stand-alone company; cost control processes (e.g., budget, billing, audits); reviews by independent third parties; operational performance statistics;

information regarding quality of management; service performance metrics; FTE statistics; and SAIDI/SAIFI data, FERC Form 1 data

The items listed above are for illustrative purposes only; the TSP shall provide whatever information necessary to meet its burden of proof.

4. Transmission expenses will include an assignment/allocation of amounts (hereinafter referred to as "assigned expenses") not recorded in transmission and distribution expense FERC accounts 560 – 574 (*e.g.*, A&G FERC accounts 920 – 935). The expenses accumulated under accounts 920-935 shall be aggregated in classes, with sufficient detail provided to enable the Commission to evaluate whether the expenses are reasonable.

SCHEDULE N: AFFILIATE DATA

Schedule N-1A:

Schedule showing transmission affiliate expenses by FERC account grouped and subtotaled by class of items for the Historic Year.

Schedule N-1B:

Schedule showing affiliate transmission expenses by FERC account grouped and subtotaled by class of items for the Forecast Year.

Schedule N-2A:

Schedule showing transmission affiliate expenses listed by affiliate by FERC account on a per book basis; specific pro-forma adjustments; and on an adjusted basis for the Historic Year

Schedule N-2B:

Schedule showing transmission affiliate expenses listed by affiliate by FERC account on an adjusted basis for the Historic Year; specific pro-forma adjustments; and on an adjusted basis for the Forecast Year

Schedule N-3A:

Organization chart for the TSP system showing all regulated and non-regulated affiliates as of the end of the Historic Year.

Schedule N-3B:

Organization chart for the TSP system showing all regulated and non-regulated affiliates as of the end of the Forecast Year.

Schedule N-4A:

Description of types of services provided by other affiliates to the TSP for the Historic Year.
Identify specific services provided by each affiliate.

Schedule N-4B:

Description of types of services provided by other affiliates to the TSP for the Forecast Year. Identify specific services provided by each affiliate.

Schedule N-5A:

Schedule showing transmission capital projects by affiliate. Amounts closed to total requested plant-in-service since the last base rate case or four years, whichever is shorter, unless ordered otherwise, and a discussion of the significant projects based on amount or project category.

Schedule N-5B:

Schedule showing transmission capital projects by affiliate amounts closed to plant-in-service from the end of the Historic Year to the end of the Forecast Year, unless ordered otherwise, and a discussion of the significant projects based on amount or project category.

Schedule N-6A:

Schedule showing adjustments to per book costs for the Historic Year including the description, purpose, and amount for each adjustment. This schedule must correlate with the Schedule N-2 listing pro-forma adjustments to Historic Year. For any adjustment where a difference exists between Schedule N-2 and this schedule reconciliation must be provided.

Schedule N-6B:

Schedule showing adjustments to per book costs for the Historic Year transmission costs including the description, purpose, and amount for each adjustment. This schedule must correlate with the Schedule 2A listing pro-forma adjustments to the adjusted Historic Year. For any adjustment where a difference exists between Schedule N-2A and this schedule a reconciliation must be provided.

Schedule N-7A:

For each class of affiliate charges in the Historic Year, this schedule will show the categories of services included in the affiliate transmission costs; the total amount in the Historic Year; a discussion of necessity and reasonableness of the services/costs; and a “no higher than” standard analysis.

Schedule N-7B:

For each class of affiliate charges in the Forecast Year, this schedule will show the categories of services included in the affiliate transmission costs; the total amount in the Forecast Year; a discussion of necessity and reasonableness of the services/costs; and a “no higher than” standard analysis.

Schedule N-8:

This schedule shall detail per book charges to other affiliate companies by FERC account. This schedule format should list the affiliate company providing the identified service.

Schedule N-9A:

Schedule N-9A applies to each TSP having affiliates that have provided services or property the value of which is included in one of the three functions. This schedule shall consist of a description of the affiliate billing process, including the manner in which costs are recorded by project/activity code or work order and the process by which costs are allocated to each affiliate. This schedule shall include allocation formulas and their derivations for the Historic Year.

Schedule N-9B:

Schedule N-9A applies to each TSP having affiliates that have provided services or property the value of which is included in one of the three functions. This schedule shall consist of a description of the affiliate billing process, including the manner in which costs are recorded by project/activity code or work order and the process by which costs are allocated to each affiliate. This schedule shall include allocation formulas and their derivations for the Forecast Year.

Schedule N-10A:

This schedule shall describe controls that are in place during the Historic Year to ensure appropriate billing for affiliate services. These controls shall include (but not be limited to) controls related to internal audits, external reviews, frequency with which allocation formulas are updated and internal procedures for challenges to affiliate expenses billed (such as billing review committees and processes for correction of billing errors).

Schedule N-10B:

This schedule shall describe controls that are in place during the Forecast Year to ensure appropriate billing for affiliate services. These controls shall include (but not be limited to) controls related to internal audits, external reviews, frequency with which allocation formulas are updated and internal procedures for challenges to affiliate expenses billed (such as billing review committees and processes for correction of billing errors).

Schedule N-11:

Schedule showing billing methods used by affiliates to bill net requested transmission costs to the TSP.

Schedule N-12:

This schedule shall show the amounts and percentages of each expense by function billed to the TSP and each affiliate for each billing method.

Workpapers shall be provided to show the calculation of the net requested affiliate amounts in the level of detail necessary for the Commission and other parties to duplicate and track the calculation of the costs Applicant has presented for recovery. These workpapers would include but not be limited to: a description of the manner in which the affiliate costs and schedules are presented; affiliate costs by witness, by class and by project/activity code or work order; project/activity or work order summaries; affiliate billings by FERC account and class; affiliate billings by class and project/activity code or work order; and affiliate billings by class, FERC account and by project/activity code or work order.

SECTION IV FORMS

Schedule W: Confidentiality Schedule

Sample Forms (Schedules : A, B, B-12, D-5, A(f), B(f), B(f)-12)

WORKPAPERS

Appendix B: Austin Energy Financial Policies

1. The term of debt generally shall not exceed the useful life of the asset, and in no case shall the term exceed 30 years.

2. Capitalized interest shall only be considered during the construction phase of a new facility if the construction period exceeds seven years. The time frame for capitalizing interest may be three years but not more than five years. Council approval shall be obtained before proceeding with financing that includes capitalized interest.

   Note: Austin Energy does not use capitalized interest.

3. Principal repayment delays shall be one to three years, but shall not exceed five years.

4. Austin Energy shall maintain either bond insurance policies or surety bonds issued by highly rated (AAA) bond insurance companies, a funded debt service reserve, or a combination of both for its existing revenue bond issues, in accordance with the Combined Utility Systems Revenue Bond Covenant.

5. A debt service reserve fund shall not be required to be established or maintained for the Parity Electric System Obligations so long as the "Pledged Net Revenues" of the System remaining after deducting the amounts expended for the Annual Debt Service Requirements for Prior First Lien and Prior Subordinate Lien Obligations is equal to or exceeds 150% of the Annual Debt Service Requirements of the Parity Electric Utility Obligations. If the "Pledged Net Revenues" do not equal or exceed 150% of the Annual Debt Service Requirements of the Parity Electric Utility Obligations, then a debt service reserve fund shall be established and maintained in accordance with the Supplemental Ordinance for such Parity Electric System Obligations.

6. Debt service coverage of a minimum of 2.0x shall be targeted for the Electric Utility Bonds. All short-term debt, including commercial paper, and non-revenue obligations will be included at 1.0x.

   Note: Debt service coverage for the FY 2017-18 Budget is 4.1x.

7. Short-term debt, including commercial paper, shall be used when authorized for interim financing of capital projects and fuel and materials inventories. The term of short-term debt will not exceed five years. Both tax-exempt and taxable commercial paper may be issued in order to comply with the Internal Revenue Service rules and regulations applicable to Austin Energy. Total short-term debt shall generally not exceed 20% of outstanding long-term debt.

8. Commercial paper may be used to finance capital improvements required for normal business operation for electric system additions, extensions, and improvements or improvements to comply with local, State and Federal mandates or regulations. However, this shall not apply to new nuclear generation units or conventional coal generation units.

   Commercial paper will be converted to refunding bonds when dictated by economic and business conditions. Both tax-exempt and taxable refunding bonds may be issued in order to comply with the Internal Revenue Service rules and regulations applicable to Austin Energy.

   Commercial paper may be used to finance voter approved revenue bond projects before the commercial paper is converted to refunding bonds.

9. Ongoing routine, preventive maintenance should be funded on a pay-as-you-go basis.

10. Austin Energy shall maintain a minimum quick ratio of 1.50 (current assets less inventory divided by current liabilities). The source of this information should be the Comprehensive Annual Financial Report.

11. Austin Energy shall maintain a minimum operating cash equivalent (also known as Working Capital) of 60 days of budgeted operations and maintenance expense, less power supply costs, plus the amount of additional monies required to bring the sum of all Austin Energy's reserves to no less than 150 days of operating and maintenance expense.

12. Net revenue generated by Austin Energy shall be used for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies, and other Austin Energy requirements. Once these obligations have been met, any remaining net revenues will be deposited in the following order into Austin Energy's reserve funds until each reserve reaches its minimum funding level: Working Capital, Contingency Reserve, Power Supply Stabilization Reserve, and then Capital Reserve. The sum of the four reserves shall be the cash equivalent of no less than 150 days of operating and maintenance expense.

13. The General Fund transfer shall not exceed 12% of Austin Energy three-year average revenues less power supply costs and on-site energy resource revenue, calculated using the current year estimate and the previous two years' actual revenues less power supply costs and on-site energy resource revenue from the City's Comprehensive Annual Financial Report.

14. Capital projects should be financed through a combination of cash, referred to as pay-as-you-go financing (equity contributions from current revenues), and debt. An equity contribution ratio between 35% and 60% is desirable.

15. The Capital Reserve shall be created and established for providing extensions, additions, replacements, and improvements to the electric system. The Capital Reserve shall maintain a minimum cash equivalent of 50% of the previous year's electric utility depreciation expense.

16. The Contingency Reserve shall be created and established for unanticipated or unforeseen events that reduce revenue or increase obligations, such as costs related to a natural disaster, extended unplanned plant outages, insurance deductibles, or unexpected costs created by Federal or State legislation. The Contingency Reserve may be used to fund unanticipated power supply expenses only after the Power Supply Stabilization Reserve has been fully depleted. The Contingency Reserve shall maintain an operating cash equivalent of 60 days of budgeted operations and maintenance expense, less power supply costs. In the event any portion of the Contingency Reserve is used, the balance will be replenished to the targeted funding level within two fiscal years.

17. Electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to support (1) the full cost (direct and indirect) of operations including depreciation, (2) debt service, (3) General Fund transfer, (4) equity funding of capital investments, (5) requisite deposits of all reserve accounts, (6) sufficient annual debt service requirements of the Parity Electric Utility Obligations and other bond covenant requirements, if applicable, and (7) any other current obligations. In addition, Austin Energy may recommend to Council in the budget directing excess net revenues for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies and other Austin Energy requirements such as working capital.

    In addition to these requirements, electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to ensure a minimum debt service coverage of 2.0x on electric utility revenue bonds.

    A rate adequacy review shall be completed every five years, at a minimum, through performing a cost of service study.