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

REBUTTAL TESTIMONY

OF

SCOTT H. BURNHAM

ON BEHALF OF AUSTIN ENERGY

JULY 7, 2022

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I. INTRODUCTION

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

A. My name is Scott H. Burnham. I am a Partner at NewGen Strategies and Solutions, LLC's (NewGen) Energy Practice. My business address is NewGen Strategies and Solutions, LLC at 225 Union Blvd, Suite 450, Lakewood, Colorado 80228. NewGen is a consulting firm that specializes in utility rates, engineering economics, financial accounting, asset valuation, appraisals, and business strategy for electric, natural gas, water, and wastewater utilities. NewGen supports clients throughout the United States.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I have a Master of Business Administration degree from the University of Colorado. Prior to this, I was awarded a Master of Public Affairs and a Master of Science from Indiana University and a Bachelor of Science degree from Texas A&M University.

Q. WOULD YOU BRIEFLY DESCRIBE YOUR PROFESSIONAL EXPERIENCE?

A. I have over 18 years of experience in the areas of cost of service (COS) and rate design for electric utilities. I have worked with electric utility senior management teams, utility boards and city councils, and attorneys with respect to the strategy and technical fundamentals of COS and rate design. I have taught numerous classes in COS and rate design methodology through EUCI, an industry conference organization, as well as for clients. These classes teach industry methodologies adopted by the National Association of Regulatory Utility Commissioners (NARUC) and the American Public Power Association (APPA). I have been extensively involved in the development of unbundled COS and pricing models throughout my career and continue to do so on a regular basis. A summary of my qualifications is provided as Exhibit SHB-1 to this testimony.

Q. ON WHOSE BEHALF ARE YOU PRESENTING THIS TESTIMONY?

A. I am testifying on behalf of Austin Energy.

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

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will explain why selected COS and rate design recommendations by Participants are inappropriate for Austin Energy and should be rejected by the Impartial Hearing Examiner (IHE).

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

A. Yes. Specifically, I have reviewed the testimony of Clarence Johnson, representing the Independent Consumer Advocate (ICA), James Daniel representing NXP USA, Inc. (NXP), and Jeffry Pollock representing Texas Industrial Energy Consumers (TIEC). Additionally, I have reviewed the cross rebuttal testimony of ICA witness Clarence Johnson.

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

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

- COS issues pertaining to:

a. The proper allocation of Austin Energy production costs;

b. The proper classification of non-fuel operations and maintenance (O&M costs);

c. The proper allocation of distribution demand costs;

d. The proper allocation for primary distribution customers; and

e. The proper treatment of adjustments for demand losses.

- Rate Design issues pertaining to:

a. Certain primary customers.

II. COST OF SERVICE

Q. PLEASE SUMMARIZE COS ISSUES RAISED BY THE PARTICIPANTS THAT YOU ARE ADDRESSING IN YOUR REBUTTAL TESTIMONY.

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

1. **Proper Allocation of Production Demand Costs**. ICA witness Johnson recommends allocation of Austin Energy production costs using the Baseload, Intermediate and Peaking (BIP) method. NXP witness Daniel and TIEC witness Pollock recommend the use of the Average and Excess 4Coincident Peak (A&E 4CP) method. Austin Energy's use of the Electric Reliability Council of Texa (ERCOT) 12 Coincident Peak 12CP Peak Demand allocator is reasonable and justified, as explained in my testimony.

2. **Proper Classification of Non-Fuel O&M costs.** ICA witness Johnson recommends classification of Austin Energy production non-fuel operations and maintenance (O&M) expenses into energy and demand. I will explain why Austin Energy's classification approach for these expense items is appropriate and reasonable.

3. **Proper Allocation of Distribution Demand Related Costs.** NXP witness Daniel and TIEC witness Pollock recommend using the 1Non Coincident Peak (1NCP) allocation method for distribution demand related costs. I will explain in my testimony why Austin Energy's use of the 12NCP allocator for these infrastructure items is more appropriate.

4. **Proper Allocation for Primary Distribution Customers**. NXP witness Daniel and TIEC witness Pollock recommend developing a rate

class for primary customers that are directly served at the substation. I explain in my testimony that there are no customers that are directly served at the substation and primary distribution customers are appropriately allocated primary distribution costs.

5. **Proper Use of Loss Factors**. NXP witness Daniel and TIEC witness Pollock recommend the use of different loss factors in the COS study. I will explain in my testimony why Austin Energy's use of the loss factors in the COS study is appropriate.

A. Allocation of Production Costs

Q. ICA WITNESS JOHNSON RECOMMENDS THAT DEMAND-RELATED PRODUCTION COSTS BE ALLOCATED TO RATE CLASSES USING THE BIP ALLOCATION METHOD. IS THE BIP ALLOCATION METHOD A REASONABLE METHOD FOR AUSTIN ENERGY?

A. No, the BIP allocation method is not appropriate for Austin Energy. This is because the BIP method is a production stacking method where baseload, intermediate, and peaking units are dispatched to meet Austin Energy's load. This allocation method is not relevant to the ERCOT nodal market, where generation units are economically dispatched into the market and not dispatched to serve Austin Energy's hourly load requirements. Generation resource terms such as baseload, intermediate, and peaking, which used to serve utilities' load, no longer have traditional meanings in ERCOT due to the structure of the ERCOT market. In this market, categorizing units as baseload, intermediate, and peaking is much less meaningful. Therefore, similar BIP categories are not relevant.

The primary concern of Austin Energy is having effective hedges to protect its customers from market price risk. These hedges can be physical or financial in nature, but in total must be sufficient to manage the market price risk for Austin Energy's total load. Power plants provide a valuable hedging tool. However, to be effective, these assets must be available and dispatchable when called into service by ERCOT.

With high availability, Austin Energy generation resources can effectively act as a financial hedge. When ERCOT market prices are high and its generation resources are available, Austin Energy simultaneously buys and sells power resulting in a net power cost equal to its cost of power production. Therefore, Austin Energy customers are protected from adverse market conditions when prices are high. During periods of low market prices, Austin Energy may only buy power from the ERCOT market (and not sell power into the ERCOT market) at a price below Austin Energy's power production costs. This approach helps keep retail rates low. Austin Energy's customers are responsible for fixed costs associated with its generation resources even if the assets are not dispatched into the ERCOT market. To make this hedge effective, Austin Energy must have its generation resource portfolio available, in a readiness state, and sufficient to meet its system load.

Q. DOES THE FINANCIAL HEDGE RELY ON GENERATION RESOURCE CAPACITY OR ENERGY CAPABILITIES?

A. One measure of the effectiveness of Austin Energy's financial hedge is the available unit capacity compared to its system demand.

Q. GIVEN THAT THE HEDGE IS BASED ON AVAILABLE CAPACITY, WHY IS THE BIP METHOD FLAWED?

A. The fundamental flaw with the BIP method is that it assumes that a resource, like a baseload unit, will be dispatched to serve load given the load profile and resource planning needs of the utility. The BIP method classifies costs based on the demand and energy needs of the system regardless of cost. However, in ERCOT, generation assets are dispatched based on market needs and price competitiveness with price being the primary factor under uncongested circumstances. In ERCOT, higher capacity factors of Austin Energy's coal (Fayette Power Project (FPP)) and nuclear (South Texas Project (STP)) units cited by ICA witness Johnson are not the result of baseload units serving load, but rather a recognition that these resources are low-cost market resources and are often called on to serve the market. These assets must perform when dispatched into the ERCOT market to provide value, therefore asset availability and associated capacity are critical. In the ERCOT nodal market, all generating units monetize their capacity value through the market clearing price. However, BIP ignores both by assigning zero capacity value to FPP and STP baseload units and assumes that these units will be dispatched into the market at any price. Therefore, BIP severely understates the capacity value of these low-cost generation resources which are often called upon to serve ERCOT load. Further, the effectiveness of the physical hedge provided by the generation fleet is a function of available capacity to offset Austin Energy's load requirements.

Therefore, fixed production costs are most appropriately associated with Austin Energy's peak load requirements, not energy. As a result, energy allocation methods, like BIP, are not appropriate.

Q. WHAT IS THE BASIS FOR UNIT DISPATCH IN ERCOT?

A. Within the ERCOT wholesale market, all generation units are economically dispatched into the market based on a bid price established by the owner. Austin Energy's bid price considers fuel cost, fuel delivery, variable O&M (VOM), startup and shutdown costs, and other factors. Given this price, ERCOT dispatches Austin Energy's generation units to serve overall market load requirements. In low price market conditions, Austin Energy generation resources may not be dispatched for long periods of time. Conversely, during high price market conditions, all Austin Energy generation resources may be dispatched. Because generation dispatch is dictated by market prices, at any given hour during the year, unit dispatch does not equal Austin Energy system load requirements. This is significantly different from the traditional vertically integrated monopoly utility model in which the BIP allocation method and other production dispatch methods were developed. Within this traditional business model, generation resources were dispatched hourly to meet system load requirements. A portfolio of generation assets often included different types of generation resources that could be categorized as baseload, intermediate, and peaking units. In this paradigm, some combination of these resources was utilized to meet a utility's system load for each hour of the year. This relationship between the hourly dispatch of generation and the hourly system load requirements no longer exists in ERCOT. Therefore, BIP and other similar generation allocation methods that heavily weigh energy use should be rejected.

Q. HOW DID THE IHE RESPOND TO MR. JOHNSON'S RECOMMENDATION TO USE THE BIP METHOD IN AUSTIN ENERGY'S 2016 RATE REVIEW?

A. The IHE recommended against the use of the BIP methodology for allocating production because it "ignores the reality of the market in which Austin Energy operates" and places too much emphasis on the market paradigm of a fully integrated utility in the non-ERCOT services areas in Texas.[1]

[1] Austin Energy's 2016 Rate Review, Impartial Hearing Examiner's Report at 166-168 (Jul. 15, 2016) (2016 IHE Report).

Q. ARE YOU AWARE OF OTHER UTILITIES IN TEXAS USING THE BIP METHOD?

A. I am not aware of any utilities in Texas using the BIP method.

Q. HOW DOES AUSTIN ENERGY MEET ITS SYSTEM LOAD REQUIREMENTS?

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

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

A. As mentioned in my testimony, the bids from generation resources dictate the dispatch of generation units in ERCOT given market conditions. Because of market conditions, with the exception of STP, Austin Energy cycles all generation units within the limits of the resource technology. Cycling is required to take advantage of market opportunities and, protect Austin Energy customers from high market prices, and act as a financial hedge. Austin Energy's generation portfolio is dispatched in the market for the financial benefit of all Austin Energy customers. Dispatchable demand, as measured by availability of generation resources, is a valuable economic component provided by the Austin Energy generation portfolio.

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

A. STP is a nuclear resource whose unit operation is strictly controlled by the United States Nuclear Regulatory Commission guidelines and dictated by the unique nature of its technology and fuel source. STP therefore operates in a "must run" situation regardless of market economic conditions.

Q. HOW DOES CAPACITY RELATE TO COST ALLOCATION?

A. To protect customers, Austin Energy must have enough available capacity to cover its load. This creates a physical and financial hedge in the market to the benefit of all customers. The hedge is based on capacity, not energy, so a customer or customer class capacity or peak demand requirements should be reflected in the cost allocation process. Allocation methods must be based on class capacity contribution or coincident peaks (CPs), specifically 12CPs.

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

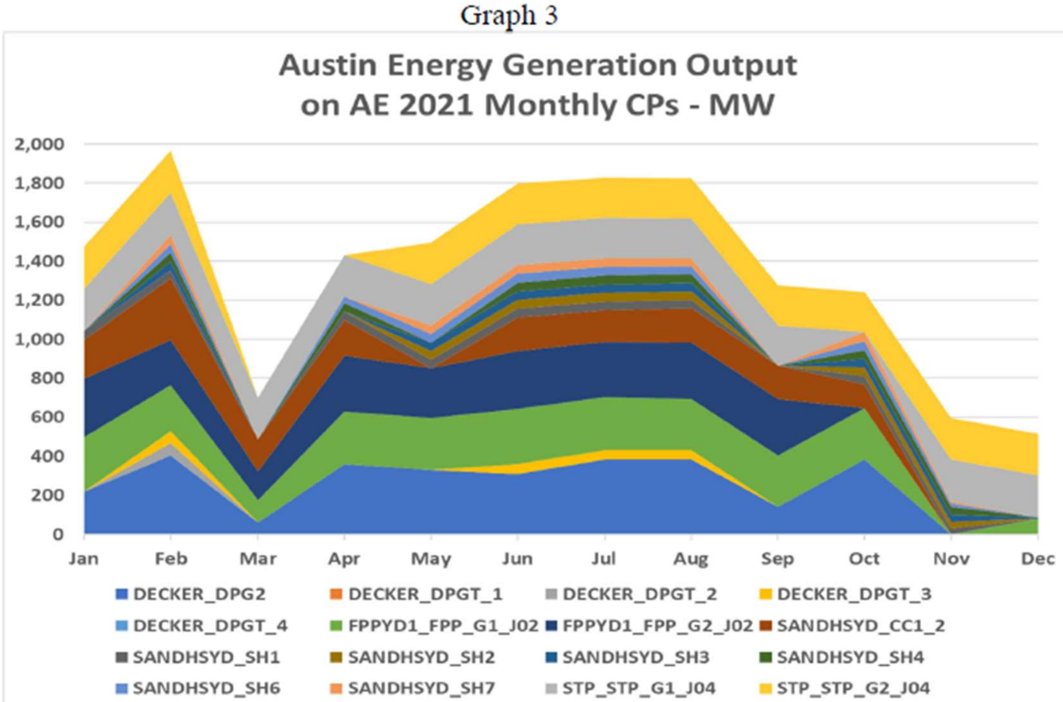
A. Yes. Austin Energy's generation assets that are available and dispatchable when market economics are favorable provide an important capacity value and financial hedge to Austin Energy customers. The effectiveness of Austin Energy's financial hedge is this availability, as measured in megawatts (MWs) compared to Austin Energy's system peak demands. Having enough dispatchable capacity to cover peak demand requirements is one way that Austin Energy manages market price risk. Therefore, demand-related costs associated with Austin Energy's generation portfolio are incurred to serve as a financial hedge. The financial hedge can only be effective if available capacity meets or exceeds the system peak. Demand-related costs associated with system capacity are incurred to meet system peaks. The proper reflection of this cost causation relationship is the use of a 12CP allocation method.

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

A. Yes, a physical hedge simply means that Austin Energy generation resources meet or exceed system load requirements. The 12CP allocation method appropriately recognizes the benefit of the capacity hedge over a greater number of peak hours during the year. This is shown in Figure 1, as provided in NXP witness Daniel's testimony.[2]

Figure 1 – Austin Energy Generation Output

Graph 3



As indicated, Austin Energy resources were significantly dispatched to meet ERCOT load during non-summer months, including January, February, April, May, and October of 2021.

Q. IS THE CAPACITY VALUE OF AUSTIN ENERGY'S GENERATION RESOURCES LIMITED TO THE FOUR SUMMER MONTHS IN ERCOT?

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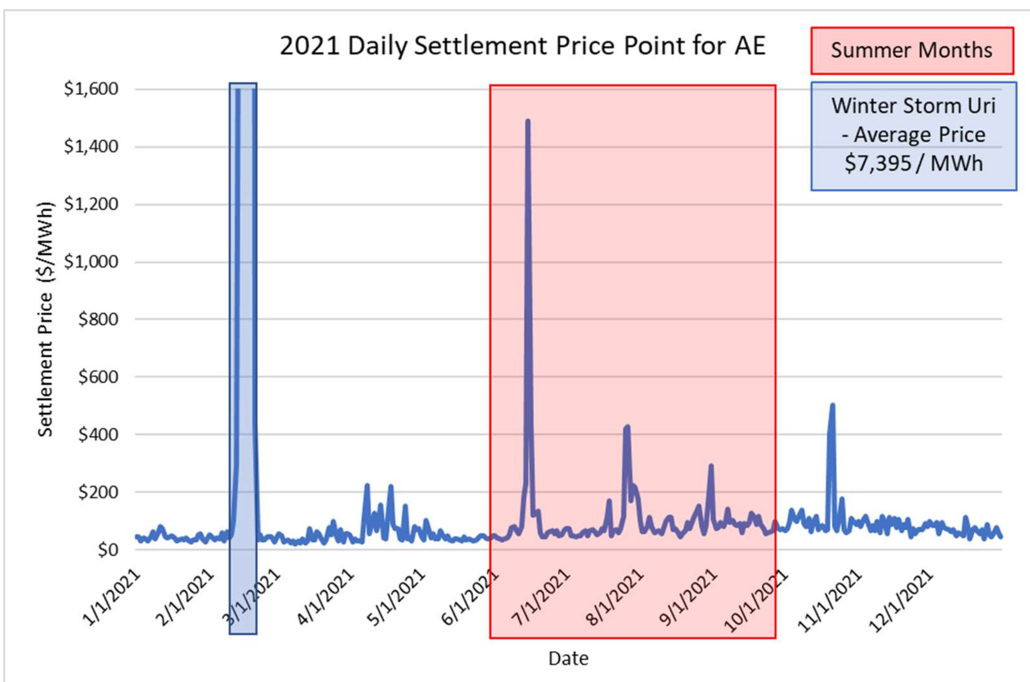
[2] NXP Position Statement at 23 (Jun. 22, 2022).

A. No. As shown in Figure 1, the capacity value of Austin Energy's resources is realized throughout the year and is not limited to the four summer months in ERCOT. As experienced during Winter Storm Uri in February 2021, Austin Energy was able to provide generation when a large portion of the ERCOT market was not able to do so. During Winter Storm Uri, average market prices were $7,395/MWh. Additionally, in 2021, ERCOT market prices experience significant increases during periods outside of the four summer months (June, July, August, September), as indicated in Figure 2, which shows the peak daily market price in $/MWh for 2021 for the Austin Energy node. As indicated, there were several days during the non-summer months, exclusive of Winter Storm Uri, which experienced an hourly price greater than $100/MWh. This proves that Austin Energy generation resources provide value to Austin Energy customers throughout the year.

Figure 2 – 2021 Daily Settlement Point Price for Austin Energy



Q. IS THE FINANCIAL HEDGE PROVIDED BY AUSTIN ENERGY'S GENERATION PORTFOLIO COMPRISED OF BOTH PRICE AND VOLUME?

A. Yes. As shown in Figure 1 (volume) and Figure 2 (price), the hedge is both price and volume. Together, they provide a physical hedge to meet Austin Energy's load as well as a financial hedge to dispatch to the ERCOT market to benefit Austin Energy customers throughout the year.

Q. NXP AND TIEC RECOMMEND USE OF THE A&E 4CP ALLOCATION METHOD. DO YOU AGREE WITH THEIR RECOMMENDATIONS?

A. No. It is true that the Austin Energy physical hedge is related to the annual system peak. However, the financial hedge benefits customers throughout the year with stable and low rates, therefore, the financial benefit must be considered. Given these reasons, the 12CP allocation approach is more equitable than the A&E 4CP method for allocating production demand costs. As discussed earlier in my testimony, Austin Energy generation assets are dispatched to the ERCOT market, not to serve Austin Energy load. As demonstrated by ICA witness Johnson, the A&E 4CP method is similar to a 4CP demand allocator.[3] However, a 12CP allocation approach is superior to a 4CP allocation approach because the 12CP recognizes the hedging value provided to customers by Austin Energy's generation portfolio over a greater percentage of peak hours. Given the unpredictability of market prices throughout the year, the benefit to Austin Energy ratepayers is more appropriately recognized over a larger number of hours.

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[3] Independent Consumer Advocate's (ICA) Cross Rebuttal Presentation of Clarence L Johnson at 6-7 (Jul. 1, 2022) (Johnson Cross-Rebuttal).

Q. WHAT IS THE HISTORY OF THE AUSTIN ENERGY PRODUCTION DEMAND COST ALLOCATION METHOD AND WHY DID IT CHANGE OVER TIME?

A. In the 2012 Cost-of-Service Study, the rate review test year was based on fiscal year (FY) 2009 operating results, which was a pre-nodal market test year. When the 2012 Cost-of-Service Study was completed, it included the A&E 4CP method. In the 2016 Cost-of-Service Study, based on several years of actual data operating in the ERCOT nodal market, Austin Energy recognized that an effective capacity hedge was a key benefit to its customers in the ERCOT nodal market, which justified utilizing an ERCOT CP basis. At that time, Austin Energy recognized that the benefit of the hedge was year-round and not just during the summer peak demand months. Accordingly, the previous demand allocator of A&E 4CP, which was essentially a 4CP allocator, was modified to a 12CP allocator. The 12CP allocator was recommended by the IHE in the 2016 Base Rate Review.[4]

Q. IS THERE A BENEFIT TO AUSTIN ENERGY RATE PAYERS TO MAINTAINING CONSISTENCY IN THE DEMAND COST ALLOCATION?

A. Yes. Austin Energy changed its demand cost allocation to the 12CP methodology in 2016. As indicated previously, the 12CP methodology provides an appropriate price signal for customers to shift load from peak demand hours in the market and provides a recognition of the value of the Austin Energy generation resources during the entire year. Consistency in cost allocation is an important element in rate design, assuming there have been no significant changes in the underlying power market operations. A consistent cost allocation method sends a consistent price signal to customers to

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[4] 2016 IHE Report at 166.

influence their electricity usage. Changing cost allocation methods sends a confusing price signal to customers, which limits the ability of customers to make optimal investments and electricity usage decisions. Maintaining the 12CP allocation methodology established in 2016 would provide consistency in Austin Energy's ratemaking process.

Q. WHAT IS THE IMPACT OF CHANGING THE 12CP ALLOCATION METHODOLOGY TO AN A&E 4CP ALLOCATION METHODOLOGY ON THE AUSTIN ENERGY CUSTOMER CLASSES?

A. The A&E 4CP has been described by ICA witness Johnson as equivalent to a 4CP allocator, as implemented by the Public Utility Commission of Texas (PUC).[5] The impact of shifting the 12CP demand cost allocation to a 4CP allocation methodology is presented by each rate class in the Table 1 below.

[5] Johnson Cross-Rebuttal at 6-7.

Table 1
Production Demand-Related Costs
Comparison of 12CP and 4 CP Cost Allocation by Austin Energy Customer Class ($000)

	12CP-ERCOT Peak	4CP-ERCOT Peak	% Change
Residential	$111,343	$117,148	5.21%
Secondary Voltage < 10 kW	$5,686	$5,341	(6.07%)
Secondary Voltage ≥ 10 < 300 kW	$53,298	$55,077	3.34%
Secondary Voltage ≥ 300 kW	$38,277	$35,764	(6.57%)
Primary Voltage < 3 MW	$5,162	$5,056	(2.07%)
Primary Voltage ≥ 3 < 20 MW	$13,541	$12,052	(11.00%)
Primary Voltage ≥ 20 MW @ 85% ALF	$22,066	$19,183	(13.07%)
Transmission	$521	$848	62.78%
Transmission Voltage ≥ 20 MW @ 85% ALF	$3,173	$2,757	(13.13%)
Service Area Street Lighting	$116	$-	N/A
City-Owned Private Outdoor Lighting	$24	$-	N/A
Customer-Owned Non-Metered Lighting	$4	$-	N/A
Customer-Owned Metered Lighting	$66	$54	(18.62%)
Total	**$253,279**	**$253,279**	**0.00%**

As shown above, shifting from 12CP to 4CP increases the residential customer class allocation by approximately 5.2% as a result of the shift from a 12CP production demand cost allocation to a 4CP production demand cost allocation.

Q. WHY DID AUSTIN ENERGY USE THE ERCOT 12CP IN CALCULATING THE 12CP ALLOCATOR?

A. Austin Energy's use of the ERCOT 12CP recognizes that there may be cost benefits associated with load diversity in the power market. The use of the ERCOT 12CP allocator develops an inherent pricing signal that encourages customers to move load from the ERCOT peak times. This pricing signal can provide long-term cost benefits on the system production systems. The ERCOT 4CP methodology is currently in use to determine what Austin Energy pays for its transmission service, which is based on the utility's contribution to the ERCOT 4CP.

B. Classification of Production Costs

Q. MR. JOHNSON RECOMMENDS RECLASSIFYING CERTAIN PRODUCTION NON-FUEL O&M EXPENSES TO INCLUDE ENERGY AND DEMAND. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No. The methodology ICA witness Johnson references for defining demand and energy portions of production accounts in the NARUC Electric Utility Cost Allocation Manual (CAM) were developed when the electric utility industry was comprised entirely of vertically integrated utilities operating in a monopoly business environment. Historically, utilities enjoyed predictable load growth with no direct competition and fixed costs could be recovered through energy charges with little financial risk. Generation assets directly served load and were dispatched regardless of cost. A common practice in rate design was to recover a large portion of fixed costs in energy charges contrary to COS results. With a large percentage of fixed costs included in energy rates, increases in energy sales associated with load growth provided long-term economic benefits to utilities. This cost classification and rate design approach no longer works in the current utility business environment.

As indicated earlier in my testimony, the ERCOT business environment is structured differently from the monopoly generation environment of vertically integrated utilities that existed when NARUC's CAM Cost Accounting classification guidelines were published. The changes in the ERCOT power market have impacted Austin Energy's business operations. Austin Energy is faced with a competitive wholesale power market, aggressive conservation and demand response goals, increased interest in distributed generation options by customers, and long-term, low-load growth projections. All these factors create load uncertainty, energy volatility, and greater revenue instability. Fixed cost recovery is no longer a certainty in the ERCOT power market or through retail rates.

Q. HOW DOES AUSTIN ENERGY'S CLASSIFICATION OF PRODUCTION COSTS DIFFER FROM THE NARUC CAM?

A. Austin Energy classifies fuel and recoverable purchased power, as well as the O&M portion of the Nacogdoches Plant, as energy-related expenses as noted by ICA witness Johnson in his testimony. This classification is consistent with the short-run view and represents a large percentage of Austin Energy's short-run variable costs. Use of the short-run view closely reflects actual variable costs incurred by Austin Energy when its generation resources units are dispatched into the ERCOT market. When Austin Energy bids generation into the market based on its short-run variable costs such as fuel costs (including delivery), variable O&M, and unit start-up and shut-down costs.

Austin Energy's classification of production variable costs aligns with the the manner in which generation resources are dispatched in ERCOT and reflects costs Austin Energy will recover its production variable costs from the ERCOT market when its units are dispatched to serve ERCOT load. Other costs above and beyond Austin Energy's short-run variable costs may be recovered from the ERCOT market, but there is no guarantee this will occur. Therefore, Austin Energy customers are ultimately responsible for some or all of the generation costs above its short-run variable costs. Because it is proper to recognize short-run variable costs as energy related, it is also proper to recognize other O&M expenses as demand related. Austin Energy generation assets must be in a state of "readiness to serve," or operationally available, when market conditions provide economic opportunities for dispatch. Prudent O&M practices are fundamental in keeping units available to operate on short notice. As noted earlier in my testimony, generation resource availability is a critical performance indicator that measures the availability of a unit to operate when the unit is "in the money," or struck in the market. With high availability, Austin Energy generation resources can effectively act as a financial hedge and protect customers from costly market events. Non-fuel-related O&M expenses ensure high availability and capacity-on-demand for all Austin Energy generation resources. Therefore, these O&M expenses are properly classified as demand-related costs in the nodal market. For these reasons, ICA witness Johnson's production function classification recommendations should be rejected.

Q. WHAT DID THE IHE RECOMMEND ON THIS ISSUE IN THE 2016 BASE RATE REVIEW?

A. The IHE found that Austin Energy dispatches its production units to meet market demand and is no longer based on the paradigm in the NARUC CAM. Further, the IHE agreed that Austin Energy's classification of production variable costs aligns with the economics of generation dispatch in ERCOT and reflects costs Austin Energy will recover from the market.[6]

C. Allocation of Distribution Costs

Q. NXP WITNESS DANIEL AND TIEC WITNESS POLLOCK RECOMMEND USING THE 1NCP ALLOCATION METHOD FOR SUBSTATIONS, POLES, AND CONDUCTORS RATHER THAN 12NCP. DO YOU AGREE WITH THEIR RECOMMENDATIONS?

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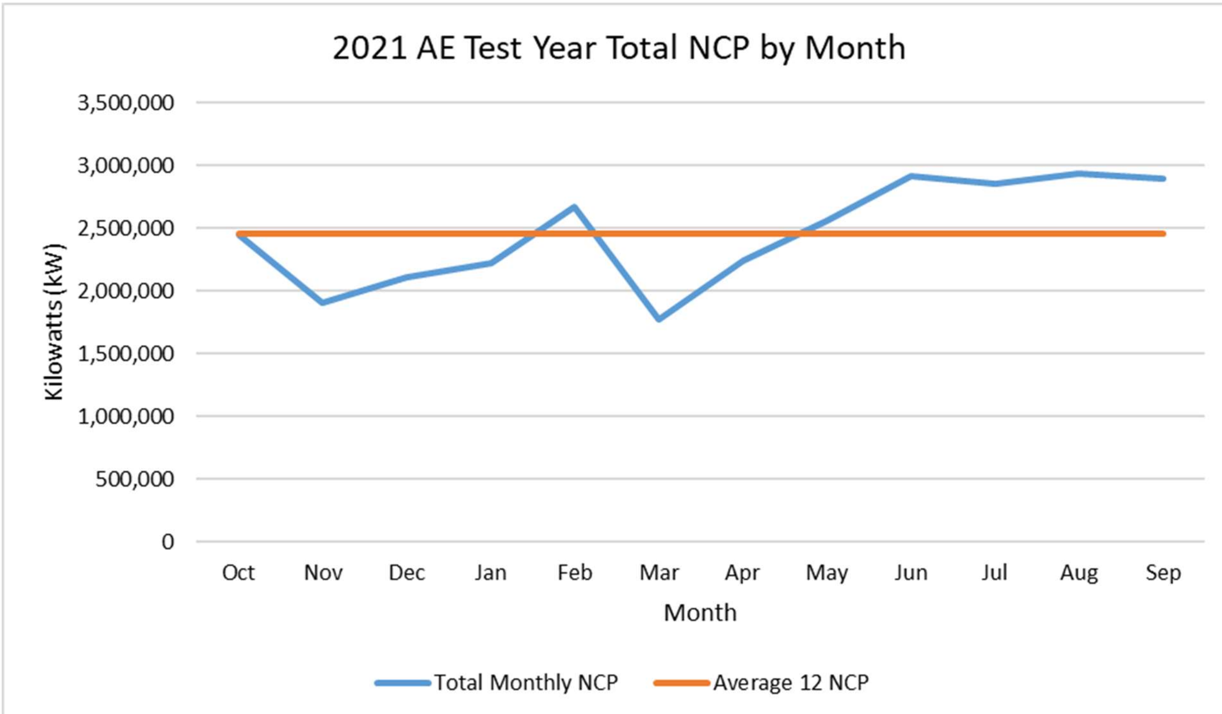
[6] 2016 IHE Report at 149.

A. No. I agree that non-coincident peak (NCP) is the proper method for allocating distribution costs, but the use of 12NCP is more equitable than 1NCP. The NCP allocation method recognizes that distribution infrastructure is sized to meet the localized maximum demands on the system. These localized demands are best measured by class non-coincident peaks (NCP). Use of a 12NCP method recognizes that distribution capacity provides value to customers throughout the year—not just during the peak hour during the summer. Because the NCP calculation is done at the class level, off-peak or seasonal customers may not be fully accounted for in a 1NCP calculation. A 12NCP calculation solves this problem. This is important as customers are installing distributed generation options and are able to shift load. From a cost allocation perspective, certain rate classes may be able to avoid a portion of distribution demand related costs by shifting demand during NCP periods. If the demand measure is a single hour (i.e., the 1NCP), the ability to shift and avoid cost responsibility is easier compared to a 12NCP method.

Q. CAN YOU EXPLAIN WHY A 12NCP APPROACH IS A MORE EQUITABLE APPROACH FOR DISTRIBUTION DEMAND COST ALLOCATION THAN A 1NCP APPROACH?

A. Yes. As indicated in the graphic below, there is sufficient variability in the monthly system NCP over the test year period (Fiscal Year [FY] 2021). A 1NCP method does not capture the variability in load and may result in certain classes not being assigned sufficient costs (the "free rider" dilemma). The 12NCP approach captures more of the diversity in the load for the customer classes and therefore does a better job of assigning costs and reduces the potential for free riders. Class contributions to the NCP vary throughout the year; therefore, an annual measure (12NCP) is fair and reasonable as it accounts for each class's use and benefit associated with the distribution system.



Q. WHAT DO OTHER MUNICIPALLY OWNED UTILITIES (MOUS) IN TEXAS UTILIZE A 12NCP METHOD TO ALLOCATE DISTRIBUTION COSTS?

A. Yes, other MOUs in Texas utilize a 12NCP method to allocate distribution costs. Specifically, Bryan Texas Utilities and Greenville Electric Utilities (Greenville, Texas) utilize the 12NCP method used to allocate distribution costs.

Q. WHAT IS THE IMPACT OF USING A 1NCP COST ALLOCATOR COMPARED TO A 12NCP COST ALLOCATOR FOR POLES, CONDUCTORS, AND SUBSTATIONS?

A. The use of a 1NCP cost allocator in place of a 12NCP cost allocator for poles, conductors, and substations would result in a shift in cost responsibility for distribution costs from the non-residential customers to the residential and small commercial (secondary voltage < 10 kilowatt [kW]) customers. I have calculated that impact in the Table 2 provided below:

Table 2
Distribution Demand-Related Costs TY
Comparison of 12NCP and 1NCP Cost Allocation by Austin Energy Customer Class ($000)

	12 NCP	1 NCP	% Change
Residential	$121,820	$124,755	2.41%
Secondary Voltage < 10 kW	$6,439	$7,848	21.89%
Secondary Voltage ≥ 10 < 300 kW	$57,472	$57,574	0.18%
Secondary Voltage ≥ 300 kW	$40,393	$38,654	(4.30%)
Primary Voltage < 3 MW	$3,907	$4,076	4.32%
Primary Voltage ≥ 3 < 20 MW	$10,437	$9,613	(7.90%)
Primary Voltage ≥ 20 MW @ 85% ALF	$15,579	$13,562	(12.95%)
Transmission	$155	$155	0.00%
Transmission Voltage ≥ 20 MW @ 85% ALF	$267	$267	0.00%
Service Area Street Lighting	$1,277	$1,221	0.00%
City-Owned Private Outdoor Lighting	$325	$353	8.40%
Customer-Owned Non-Metered Lighting	$52	$57	8.57%
Customer-Owned Metered Lighting	$390	$379	(2.70%)
Total	**$258,514**	**$258,514**	**0.00%**

Q. DOES ICA WITNESS JOHNSON AGREE WITH AUSTIN ENERGY'S 12 NCP METHOD OF ALLOCATING DISTRIBUTION COSTS?

A. Yes. In ICA witness Johnson's cross rebuttal testimony, he indicates that 12NCP is within the range of reason for allocating distribution costs because it recognizes the load diversity and localized nature of distribution planning.[7] I agree with ICA witness Johnson on this point.

[7] Johnson Cross-Rebuttal at 8-9.

D. Losses used for CP/NCP

Q. NXP WITNESS DANIEL AND TIEC WITNESS POLLOCK RECOMMEND THE USE OF DEMAND LOSSES FOR CP COST ALLOCATION.[8] DO YOU AGREE WITH THIS RECOMMENDATION?

A. Yes, ideally demand losses should be utilized to adjust load. However, Austin Energy only has a demand loss measured for the peak hour of the year (1CP). Austin Energy does not have a demand loss measured for each peak hour of the month applicable to the 12CP cost allocation. Losses would be expected to be different at different loads and different ambient temperatures throughout the year. Therefore, the use of the average energy loss as a proxy for the 12CP demand loss is reasonable.

Q. NXP WITNESS DANIEL AND TIEC WITNESS POLLOCK RECOMMEND THE USE OF DEMAND LOSSES FOR NCP COST ALLOCATION.[9] DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. The NCP of a customer class may occur at any time during the month and the losses associated with the peak for the class would prove difficult to measure on a consistent and regular basis. Therefore, the use of the average energy losses as a proxy for the 12NCP demand loss is reasonable.

Q. TIEC WITNESS POLLOCK PROVIDED EXHIBITS TO HIS TESTIMONY REGARDING PROPOSED LOSS CALCULATIONS.[10] DO YOU AGREE WITH THE PROPOSED LOSS CALCULATIONS HE PROVIDED?

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[8] Direct Testimony of Jeffry Pollock, on behalf of Texas Industrial Energy Consumers (TIEC) at 36 (Jun. 22, 2022) (Pollock Direct); NXP Statement of Position at 37-38 (Jun. 22, 2022).

[9] *Id*.

[10] Pollock Direct; *See* Exhibit JP-8.

A. No. Based on a review by Austin Energy of the TIEC Loss Factor spreadsheet, there are several concerns with the analysis provided. One concern is that the same demand loss factor appears to have been applied to the CP hour and similarly the same demand loss factor for the NCP hour for each month, which does not take into account variations in demand or ambient conditions by season.

E. Primary Substation Cost Allocation and New Rate Class

Q. NXP WITNESS DANIEL AND TIEC WITNESS POLLOCK RECOMMEND REMOVING THE ALLOCATION OF PRIMARY DISTRIBUTION POLES AND LINES FOR THE PRIMARY VOLTAGE ABOVE 20,000 KW CLASS TO CREATE A SEPARATE RATE CLASS.[11] DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. Austin Energy serves three primary >= 20,000 kW customers. None of these customers are served directly from any substation on Austin Energy's system, as Austin Energy's policy does not allow this to occur. The point of interconnection (POI) for all customers is outside of the Austin Energy substation. Austin Energy must install and maintain the primary distribution poles and lines to serve customers up to the POI regardless of the geographic location of the interconnection point. Distribution feeders can be direct or shared and are comprised of some combination of Austin Energy owned and maintained overhead and/or underground conductors. Further, distribution feeder lengths vary between a few hundred feet up to several miles and there is no direct correlation between the location of the substation and a customer's property. In addition, it is common ratemaking practice to recover system costs on a class average basis regardless of the physical location of the interconnection. Therefore, primary

[11] Pollock Direct at 31-34; NXP Statement of Position at 32-34.

voltage customers should be allocated costs for the primary distribution poles and lines that are part of these feeders.

Q. NXP WITNESS DANIEL AND TIEC WITNESS POLLOCK INDICATED IN THEIR TESTIMONY THAT HIGH LOAD FACTOR VOLTAGE (=> 20,000 KW) CUSTOMERS ARE DIRECTLY CONNECTED TO AN AUSTIN ENERGY DISTRIBUTION SUBSTATION THROUGH DEDICATED FEEDERS.[12] IS THIS TRUE?

A. No. They relied on a discovery response that was subsequently revised. Initially, Austin Energy's response to TIEC TC2-1A and in the second technical conference, Austin Energy stated that all customers in the primary are "directly" connected to Austin Energy substations.[13] Austin Energy subsequently revised that response to state that there are no primary >=20,000 kW customers that are served directly from the substation.[14] Austin Energy does not allow customer-owned equipment in its substations for safety concerns. Therefore, no customers are allowed to directly connect to Austin Energy substations. This was corrected by Austin Energy in an amended response to TIEC TC2-1A.[15]

Q. NXP WITNESS DANIEL AND TIEC WITNESS POLLOCK BOTH REFERENCE AN ONCOR RATE CASE AS RATIONALE FOR AUSTIN ENERGY TO EXCLUDE PRIMARY DISTRIBUTION COSTS TO THESE

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[12] *Id*.

[13] "Austin Energy's Technical Conference 2-Follow Up Responses (May 27, 2022)."

[14] "Austin Energy's Technical Conference-Amended Follow Up Responses (Jun. 10, 2022)" (Provided as Exhibit SHB-2).

[15] *Id*.

CUSTOMERS.[16] IS THE ONCOR RATE CASE RELEVANT TO AUSTIN ENERGY'S BASE RATE REVIEW?

A. No. The Oncor rate case is not relevant to Austin Energy's situation for primary voltage distribution customers. As noted in the Order on Rehearing, the PUC approved the creation of a new primary substation rate class for Oncor. However, this approval was conditioned upon customers "construct[ing] and maintain[ing] the distribution facilities themselves".[17] In contrast, Austin Energy owns and maintains the distribution facilities necessary to serve its primary voltage customers load up to the point of interconnection.

Q DO YOU AGREE WITH NXP WITNESS DANIEL THAT BASED ON AUSTIN ENERGY'S AMENDED TECHNICAL CONFERENCE RESPONSE, SPECIFIC COSTS FOR SELECTED PRIMARY DISTRIBUTION SYSTEM FACILITIES SHOULD BE RECOVERED IN A UNIQUE FACILITIES CHARGE?

A. No. Primary distribution customers are within the primary distribution class and should be allocated a proportional share of the costs for the primary distribution system as developed by Austin Energy and included in the proposed base rate charge.

Q. DOES ICA WITNESS JOHNSON AGREE WITH AUSTIN ENERGY'S APPROACH TO ALLOCATE PRIMARY DISTRIBUTION COSTS TO CUSTOMERS NEAR OR ADJACENT TO SUBSTATIONS?

A. Yes. In ICA witness Johnson's cross rebuttal testimony, he agrees with Austin Energy's approach to allocate primary distribution costs to customers near or adjacent

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[16] Pollock Direct at 31-34. NXP Statement of Position 32-34.

[17] *Application of Oncor Electric Delivery Company LLP for Authority to Change Rates*, PUC Docket No. 35717, Order on Rehearing at 11 (Nov. 30, 2009).

to substations as it is consistent with average cost ratemaking principles.[18] Further, he states that the complaint by TIEC witness Pollock and NXP witness Daniel that some industrial customers do not use all of the primary facilities is not a valid reason for shifting primary voltage costs onto other customers.[19] Additionally, he states that the TIEC proposal is a form of geographic ratemaking, which is avoided by average cost ratemaking. I agree with ICA witness Johnson on this point.

III. RATE DESIGN

Q. DO YOU AGREE WITH TIEC WITNESS POLLOCK REGARDING HIS RECOMMENDATION FOR THE CREATION OF A PRIMARY SUBSTATION RATE CLASS?

A. No. As indicated previously in my testimony, there are no customers that directly connect to Austin Energy's substations. Therefore, there is no basis for a Primary Substation rate class.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE PRIMARY DISTRIBUTION CUSTOMER CLASS?

A. Yes. Primary Voltage >= 20,000 kW >85% average load factor (ALF) customers, as well as Primary Voltage >= 3,000 kW and < 20,000 kW customers, are receiving a benefit in their base rates as a result of not being served by the secondary distribution system. Thus, these three customers are already in a unique rate class.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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[18] Johnson Cross-Rebuttal at 9-10.

[19] *Id*.

NewGen Strategies & Solutions

Scott H. Burnham
Partner
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Mr. Scott Burnham joined NewGen Strategies and Solutions, LLC (NewGen) in April 2016. He offers over 22 years of experience in the areas of cost of service (COS) and rate design analysis, financial feasibility, asset valuation, and restructuring for electric utilities.

Mr. Burnham leads the comprehensive and independent review of cost of service and retail rate design practices for various electric utilities, including analyzing the impacts of net metering, feed-in tariffs, and ways to enhance fixed cost recovery in the face of increasing levels of distributed generation on clients' systems. Additionally, he has taught numerous classes on cost of service and rate design methodology, including courses for Electric Utility Consultants, Inc.

Mr. Burnham conducts acquisition, privatization, and competitive assessments, which includes the development and evaluation of financial models that provide clients with an assessment of the impacts associated with several technical and financial feasibility alternatives. These analyses include impacts to projected net operating results from potential financings, investments, and other client actions. His efforts have involved assessing public versus private utility ownership, developing sales and revenue summaries, analyzing utility investment options, and reviewing power price trends.

EDUCATION

- Master of Business Administration in Finance, University of Colorado
- Master of Public Affairs and Master of Science, Indiana University
- Bachelor of Science, Texas A&M University

KEY EXPERTISE

- Retail Rate and Cost of Service
- Unbundled Cost Analysis
- Rates Negotiation
- Economic Evaluation
- Feasibility and Financial Analyses

RELEVANT EXPERIENCE

Cost of Service and Rate Design

Mr. Burnham participates in and leads the review of cost of service and retail rate design practices for numerous electric utilities. Services provided include development of historical and projected revenue requirements and defensible cost allocation methodologies to apply to clients' customer classes. He has utilized COS methodologies unbundling approaches, cost classification techniques, cost allocation methods, and rate design alternatives. He has provided the technical and financial analysis associated with the distribution, transmission, and generation functions of the utility.

Mr. Burnham has led projects requiring re-classification of large energy users within the system from contract rates to tariff rates. Mr. Burnham has determined fixed cost allocation by customer class from detailed feeder analysis, provided testimony support of revenue requirement in a litigated hearing process, and developed testimony to support utility response for Feed-In Tariff programs.

Mr. Burnham has provided the methodology and analysis to determine the value associated with various distributed solar technologies and has explored rate options that are designed to improve fixed cost recovery in the face of increasing levels of distributed generation on clients' systems. This has included working with clients on reforming existing net energy metering rates. He has also reviewed existing COS analysis associated with the street lighting and traffic lighting retail rate classes. He has developed specific rates and rate programs for the industrial customer base, including the development of interruptible rate offerings that provided a benefit to both the industrial customer and the client.

Mr. Burnham has been responsible for leading the analysis and development of the presentations and reports and for presenting results and recommendations, including proposed rates before city councils and governing boards. Additionally, he has been involved in facilitating citizen's advisory groups and stakeholder processes to solicit input into rate design. Mr. Burnham's cost of service and rate design clients include:

- American Samoa Electric Utility, American Samoa
- Arizona Public Service Company, Arizona
- Aurora, Colorado
- Austin Energy, Texas
- Colorado Springs Utilities, Colorado
- Dover Electric System, Delaware
- Farmington Electric Utility System, New Mexico
- Fort Collins Utilities, Colorado
- Georgetown Electric Utility, Texas
- Lafayette Consolidated Government, Louisiana
- Platte River Power Authority, Colorado
- Redding Electric Utility, California
- Riverside Public Utilities, California
- San Francisco Public Utility Commission, California
- Silicon Valley Power, California
- South Carolina Public Service Authority (Santee Cooper), South Carolina
- Turlock Irrigation District, California
- Vermont Public Service Department, Vermont
- Virgin Islands Water and Power Authority, U.S. Virgin Islands

Feasibility Studies and Financial Analyses

Mr. Burnham has developed financial models designed to inform clients' decisions regarding the associated impacts of multiple technical and financial feasibility scenarios. Mr. Burnham reviews clients' financial projections and structures and develops pro forma financial models to determine projected revenue and costs associated with various projects and financing approaches for a variety of power generation facilities. These financial models focus on the development of operating results, debt service coverage ratios, and other applicable financial metrics within the terms of a proposed financing effort. His models and associated reports have been relied upon to assess investment decisions within the capital markets.

Mr. Burnham has developed projected operating results for consulting engineering reports and associated financing certifications; provided financial models that included the technical, financial, and economic input parameters to optimize value of multiple generation siting alternatives; and developed a pro forma financial model for portfolio financing of over 7,500 megawatts of generation capacity. Clients include:

- Arizona Public Service, Arizona
- Black Hills Energy, Colorado
- Brownsville Public Utilities Board, Texas
- Central Electric Cooperative, South Carolina
- City of Chicago, Illinois
- CORE Electric Company, Colorado
- City of Decorah, Iowa
- El Paso County, Colorado
- Ember Infrastructure LLC, New York
- Escalante H2 Power, Texas
- Fortis Capital Corp., Santiago, Chile
- Lafayette Consolidated Government, Louisiana
- Lehman Brothers, California
- Wyoming Municipal Power Agency, Wyoming

- Duke Energy, North Carolina

Asset Appraisals and Valuations

Mr. Burnham has conducted and managed appraisals and valuations for generation assets and transmission and distribution systems. These models have been used to determine the value of assets and asset-related cash flows, including royalties and municipal transfers. He also analyzes market data to determine comparable sales data for appraisal valuations. Additionally, he has assisted with the development of replacement and original cost less depreciation analyses. Mr. Burnham has assisted and conducted several on-site evaluations of asset condition, and observable operations and maintenance procedures. Clients include:

- Christian County Generation LLC, Nebraska
- City of Dallas Sanitation Services Department, Texas
- CPS Energy, Texas
- International Power America, Inc., Texas
- Nuclear Innovation North America, LLC, Texas
- Prisma Energy International, Istanbul, Turkey

WORKSHOPS AND PRESENTATIONS

Mr. Burnham has given numerous presentations and participated in training and workshops. These activities have focused on cost of service, ratemaking, and distributed energy resources. Host organizations and the topics Mr. Burnham presented are displayed below.

Electric Utility Consultants, Inc. (EUCI)

- *Introduction to Cost of Service Concepts and Techniques for Electric Utilities*
- *Distributed Energy – Cost / Benefit Analysis Summary / Methodology*
- *Introduction to Rate Design for Electric Utilities*

Indiana State Bar Association – Utility Law Section

- *Electric Ratemaking Workshop (CLE Credit Course)*

Municipal Electric System of Oklahoma (MESO)

- *Distributed Energy Resources Workshop*
- *Cost of Service / Rate Design Workshop*

American Public Power Association

- *Review of AMI Investment Decision (with LUS)*

RMEL (formerly Rocky Mountain Electrical League)

- *Cost of Service and Utility Rate Design*

Western Load Research Association

- *Integrating Load Analyses into the Cost of Service and Rate Design Process (with Redding Electric Utility)*

Northwest Public Power Association

- *Blue Sky Rates Facilitation Workshop*

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

AUSTIN ENERGY'S AMENDED RESPONSES TO QUESTIONS RELATED TO TECHNICAL CONFERENCE #1 AND #2

Austin Energy held Technical Conferences on Thursday, May 5, 2022 and Wednesday, May 18, 2022, to allow Participants to ask questions related to the 2022 Austin Energy Base Rate Review. Austin Energy answered all questions asked during the Technical Conferences either in person or via filed responses. Austin Energy now amends some of its responses to these questions.

Respectfully submitted,

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ATTORNEYS FOR THE CITY OF AUSTIN D/B/A AUSTIN ENERGY

Austin Energy's Amended Responses to Questions from Texas Industrial Energy Consumers (TIEC)

TIEC TC 1-2: Do any of the customers in the Primary Voltage Over 3 MW and Over 20 MW Over 85% ALF classes take delivery service directly from Austin Energy-owned distribution substations?

a. If so, what portion of the 12NCP loads of these classes is represented by customers taking delivery service directly from Austin-Energy owned substations?

b. What is Austin Energy's rationale for allocating the costs of primary distribution poles, towers, fixtures, overhead/underground conductors and devices, and conduit to customers that take service directly from a distribution substation?

ANSWER: No. After discussing the issue concerning direct service from a substation, there are customers that receive service from a direct feeder from a substation. All customers receiving service from a direct feeder receive power outside the substation. The point of interconnection, where the facilities change from Austin Energy to the customer, occurs outside the substation.

TIEC TC 2-1A: In its response to TIEC TC 1-2, Austin Energy stated that customers in the Primary Voltage Over 3 MW and Over 20 MW classes take delivery service directly from Austin Energy-owned distribution substations: Confirm that all of the Primary Voltage Over 20 MW customers are served directly from Austin Energy owned distribution substations. If not confirmed, list the customers who are not served directly from Austin Energy owned distribution substations.

ANSWER: Not confirmed.

TIEC TC 2-1B: In its response to TIEC TC 1-2, Austin Energy stated that customers in the Primary Voltage Over 3 MW and Over 20 MW classes take delivery service directly from Austin Energy-owned distribution substations: Confirm that all of the Primary Voltage Over 3 MW and less than 20 MW customers are served directly from Austin Energy owned distribution substations. If not confirmed, list the customers who are not served directly from Austin Energy owned distribution substations.

ANSWER: Not confirmed.