AUSTIN ENERGY 2016 RATE REVIEW

AUSTIN ENERGY'S TARIFF PACKAGE UPDATE OF THE 2009 COST OF SERVICE STUDY AND PROPOSAL TO CHANGE BASE ELECTRIC RATES	**§ § § §**	**BEFORE THE CITY OF AUSTIN IMPARTIAL HEARING EXAMINER**

DIRECT TESTIMONY AND EXHIBITS OF

GARY L. GOBLE

ON BEHALF OF

NXP SEMICONDUCTOR, INC.

AND

SAMSUNG AUSTIN SEMICONDUCTOR, INC.

MAY 3, 2016

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I. INTRODUCTION, QUALIFICATIONS, AND EXPERIENCE

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

A. My name is Gary L. Goble. I am a management consultant with the firm Management Applications Consulting, Inc. ("MAC"). MAC's primary offices are located at 1103 Rocky Drive, Suite 201, Reading, Pennsylvania 19609. My office is located at 11400 West Parmer Lane, #44, Cedar Park, Texas 78613.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing and providing testimony on behalf of NXP Semiconductor, Inc. ("NXP") and Samsung Austin Semiconductor, Inc. ("Samsung"). NXP and Samsung are among Austin Energy's ("AE") largest customers in terms of energy usage and demand and, as major employers and businesses in Austin, have a vital interest in the Austin community and economy. In this proceeding, I am working with Ms. Marilyn Fox of Fox/Smolen and Associates, who is also appearing on behalf of NXP and Samsung.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND EMPLOYMENT EXPERIENCE.

A. I am a consultant with over 42 years of experience in utility regulatory matters. I have an undergraduate degree ("BSPA") from the University of Arkansas at Fayetteville, Arkansas, and a graduate degree ("MBA") from St. Edward's University in Austin, Texas. I have worked as a staff analyst for the Arkansas Public Service Commission and the Public Utility Commission of Texas ("PUC"), and as a consultant to investor-owned electric and natural gas utilities, municipally-owned electric utilities, electric cooperatives, and large electric consumers. I have testified before state and local regulatory agencies and boards on numerous occasions. The primary focus of my work experience has been in the areas of economic analysis, cost analysis, and pricing. A more detailed description of my qualifications and experience is provided in Exhibit GLG-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My direct testimony addresses matters relating to (a) certain adjustments to AE's base rate revenue requirement including AE's proposal to recover certain costs through "flow through" adjustments; (b) class cost of service allocations; (c) revenue level changes among rate classes; and (d) the disparity between AE's generation costs and the market price of power purchases from the Electric Reliability Council of Texas ("ERCOT").

Q. WHAT EXHIBITS DO YOU SPONSOR?

A. I sponsor Exhibits GLG-1 through GLG-5 as set forth in the table of contents and attached to this testimony.

Q. WERE THE EXHIBITS YOU ARE SPONSORING PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, they were.

Q. ARE THE TESTIMONY AND THE CONTENTS OF THE EXHIBITS YOU SPONSOR TRUE AND ACCURATE TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes, they are.

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

My direct testimony consists of six sections. Section I provides my qualifications and experience and describes the purpose and organization of my testimony. Section II addresses adjustments to AE's other revenue and transmission expense resulting from updating the ERCOT Postage Stamp Rate consistent with the 2016 rate. Section II of my testimony also addresses the need to correct AE's proposed "Billing Adjustment," which AE employed to adjust for differences between booked revenue and the revenue calculated by rebilling booked billing determinants. Section III describes the class cost of service study sponsored by AE witness Mr. Mark Dombroski,[1] identifies several recommended changes to the allocations contained in AE's class cost of service model, and summarizes the revised model results. Section IV of my direct testimony discusses and provides recommendations regarding the distribution of the revenue requirement by customer class. This section also addresses concerns regarding cost-based rates and customer impact. Section V provides my recommendations regarding re-establishing Service Area Street Lighting as a separate stand-alone customer class to which standard rates should apply. Section VI compares the costs associated with generation by AE to the market price of power from ERCOT and recommends that the Impartial Hearing Examiner ("IHE") require AE to submit certain periodic generation information to the Austin City

[1] Unlike in a formal contested rate proceeding before the Public Utility Commission, AE did not file its Tariff Package in the form of direct testimony, instead AE provided its recommendations in the form of a narrative without attribution of content to specific witnesses. In response to NXP/Samsung's 1st RFI, number 1-9, AE indicated that Mr. Dombroski is responsible for questions relating to Chapter 5 of the Tariff Package, which is the section of that document that addresses class cost of service and cost allocation matters. *Austin Energy's Tariff Package: 2015 Cost of Service Study and Proposal to Change Base Electric Rates*, Austin Energy's Response to the First Request for Information from NXP Semiconductors and Samsung Austin Semiconductor, LLC's at 1-9 (Feb 28, 2016).

Council for review so that the Austin City Council can have up to date information on any difference in pricing. Finally, Section VII provides a summary of my testimony and recommendations.

II. ADJUSTMENTS TO AE'S PROPOSED BASE RATE REVENUE REQUIREMENTS

Q. DESCRIBE THE ADJUSTMENTS TO AE'S REVENUE REQUIREMENT THAT YOU PROPOSE.

A. I proposed two adjustments to AE's revenue requirement. First, I recommend that AE's transmission cost of service be revised to comport with the Order issued by the PUC in Docket No. 45382.[2] In that Order, the ERCOT Postage Stamp Rate was increased for AE's transmission payments and revenues. As a result, AE's revenues for transmission provided for others and expenses for transmission provided by others both increased. Ms. Fox provides numeric support and additional information regarding this adjustment.

Second, I recommend that AE's calculation of its "Billing Adjustment Factor," set forth on WP G-10.1.1, be rejected and replaced with an accurate method of accounting for differences between book revenue and rebilled revenue. By rebilled revenue I refer to the revenue obtained by multiplying booked billing determinants times the applicable rate. Rate revenue adjustments such as AE's Billing Adjustment Factor are generally referred to as "Book to Bill" adjustments. For many customer classes booked revenue often differs from the revenue one calculates by multiplying the booked usage by the applicable rate. These differences occur as a result of a number of factors that are

[2] *Commission Staff's Application to Set 2016 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Docket 45382, Order (Mar. 25, 3016).

common in electric utility billing systems, including adjustments to correct errors in prior month billings, adjustments for estimated meter readings, partial month billings due to connections and disconnections, and other similar billing adjustments. These factors are normal occurrences for most utilities and result in differences like those AE attempts to address in WP G-10.1.1.

Q. IF BOOK TO BILL ADJUSTMENTS, WHICH AE REFERS TO AS A BILLING ADJUSTMENT, ARE NORMAL OCCURRENCES FOR MOST UTILITIES, WHY ARE YOU RECOMMENDING THAT AE'S PROPOSED BASE RATE REVENUE ADJUSTMENT, DETERMINED BY USE OF THE BILLING ADJUSTMENT, BE REJECTED AND REPLACED WITH AN ALTERNATIVE CALCULATION?

A. AE's method of adjustment is inconsistent with industry practices, not supported by any evidence, and unfairly shifts cost increases among customer classes. As shown on WP G-10.1.1, AE's system billing adjustment is made on a pro-rata basis for every customer class. More specifically, AE applies the same adjustment factor to each class even though each class is not equally responsible for the billing difference for which AE is intended to compensate. AE has failed to make the adjustment on a class-by-class basis as is the standard practice in the utility industry. AE has, with no support whatsoever and contrary to reason, assumed that each and every customer class has exactly the same negative 0.47 percent Book to Bill ratio (i.e. Billing Adjustment Factor).

In 42 years of analyzing rates in several hundred utility rate cases, I have never observed every customer class being equally responsible for billing differences; the relationship between booked revenue and rebilled revenue differs among customer classes, often by significant amounts. AE could, and should, have made class specific adjustments with the information available on WP G-10.1.1.1. According to AE's response to NXP/Samsung's 6 RFI, number 6-10, AE claims it was unable to calculate FY14 base rate revenues by class because such revenues "... are not easily attributed to customer classes, due to accounting system limitations and the imprecision of assigning long-term contract customers to the appropriate current rate classes."[3] It is important to note that I could and would have proposed such an adjustment using the information set forth on WP G-10.1.1.1, if it was not for AE unreasonably hiding the rebilled revenue results for all of its 13 customer classes on that workpaper. It is noteworthy that AE hid the calculated base rate revenue amounts of all customer classes from intervenors even though there are no confidentiality concerns for 8 of these customer classes. This prevented me (and all other parties) from making a class-by-class correction to the present and proposed revenue recoveries.

In my experience, large customers in customer classes having relatively few customers rarely have a significant mismatch between booked revenue and rebilled revenue. Large customers like NXP and Samsung review meter readings and billing calculations on a real time basis and any reading errors tend to be captured at the time the errors occur. Because of this, out of period adjustments do not often occur for very large customers. Furthermore, AE's large customer classes were stable in number during the

[3] *Austin Energy's Tariff Package: 2015 Cost of Service Study and Proposal to Change Base Electric Rates*, Austin Energy's Response to NXP Semiconductors' and Samsung Austin Semiconductor, LLC's Sixth Request for Information at 6-10 at 10 (Apr. 18, 2016).

test year and have not been subject to billing pro-rations that result from connects and disconnects, and therefore, no adjustment is appropriate for these customer classes. In contrast, classes like Residential customers are more subject to pro-rated monthly billings, particularly when large student populations connect and disconnect during the year, resulting in partial month billings and are, therefore, responsible for the differences in revenue that necessitate a billing adjustment. Finally, there are very few large customer on AE's system, and the effort to rebill the rates for these few customers should not be difficult.

For these reasons, I recommend that AE's Billing Adjustment either: (a) be rejected altogether due to a lack of evidence that the adjustment is accurate by class, AE's failure to provide any support for the manner by which the adjustment is calculated, and because the adjustment is neither fair nor reasonable to large customers such as NXP and Samsung, who experience little need for billing adjustments; or, (b) that the entire adjustment of $2,972,575 be distributed only among those classes that most likely caused this difference between booked and rebilled revenue to occur. The latter is more equitable, although I consider either approach to be a preferable alternative to AE's unsupported and misapplied adjustment.

Exhibit GLG-2 sets forth my recommended corrected WP G-10.1.1.1 in which the $2,972,575 adjustment is distributed among all classes other than the large customer classes because these classes are unlikely to have contributed to the under-statement of revenue. The classes that should receive no upward Billing Adjustment include Primary Voltage $\geq 3 < 20$ MW; Primary Voltage ≥ 20 MW; Transmission Voltage; Primary

Voltage ≥ 20 MW @ 85% aLF[4]; and Transmission Voltage ≥ 20 MW @ 85% aLF. These classes contain few customers who rarely need billing adjustments and for whom an accurate calculation of the actual Book to Bill adjustment could, and <u>should</u>, have been made. The result of the adjustments made in GLG-2 adjustment is to decrease the adjusted test year base rate revenues for those classes that are most likely to have produced the $2,972,575 revenue under-billing, while increasing the adjusted test year base rate revenue for those classes identified above. The impact of this correction of AE's unsupported, unfair, and unreasonable billing adjustment is provided on Exhibit GLG-2.

III. CLASS COST OF SERVICE STUDY RECOMMENDATIONS

Q. GENERALLY DESCRIBE AE'S CLASS COST OF SERVICE STUDY.

A. AE's revenue requirement model includes an embedded class cost of service study ("CCOS") that apportions the utility's proposed total electric system revenue requirements to each customer class. AE's CCOS follows the standard industry practice for conducting such a study, which consists of a three step process. The steps in conducting an embedded CCOS include functionalization, classification, and allocation.

Functionalization refers to the categorization of costs as being production (or power supply) related, transmission related, distribution related, and other. For the most part, the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOC") provides the basis for functionalizing plant and expenses on the books and records of the electric utility. Functionalized costs may be further grouped into sub-

[4] aLF refers to annual load factor.

functions to provide more specificity in cost drivers. AE has sub-functionalized production expenses into Coal, Natural Gas, Nuclear, and various categories of renewable power supply expenses, and distribution expenses into Primary Substations, Transformers, Services, etc., to better reflect the underlying influences upon these costs.

Classification refers to the categorization of functionalized costs according to the primary utility operation for which functionalized dollars are spent – i.e., demand, energy, and customer costs. Demand costs are those costs that vary as a result of the rate at which power is used over a short duration of time (generally 60 minutes or less); transmission costs are an example of demand costs. Energy costs are those costs that vary depending upon the total quantity of energy supplied over a period of time (generally a month or a year); fuel expense is an example of energy costs. Customer costs are those costs that vary as the number of customers varies, for example, the cost of individual meters. Similar to the process by which functional costs are further grouped by sub-function, costs which have been classified as being demand, energy, or customer related can be further divided into categories that more accurately address the factors that drive these costs. For example, AE has further classified production costs into 18 sub-classifications as set forth in Schedule G-2, transmission-related costs into three sub-classifications as set forth in Schedule G-3, distribution costs into seven sub-classifications as set forth in Schedule G-4, and customer-related costs into six sub-classifications as set forth in in Schedule G-5.

Once costs have been functionalized and classified, they are allocated (or directly assigned) to individual customer classes based upon a metric that reflects the manner in which costs are incurred. For example, transmission costs are assigned on the basis of summer peak demands because these demands are the cost driver for transmission investment and the related transmission expenses. Fuel costs are assigned on the basis of energy sales, adjusted for line and transformation losses to the generation voltage. The costs of meter investment are assigned on the basis of the number of customers weighted by the relative costs of the meters serving the class.

After all costs have been functionalized, classified, and allocated, the individual cost components are totaled to determine the total cost to serve each individual customer class. Because the total costs of all classes equals the total electric system revenue requirement, this type of cost study is generally referred to as a fully-distributed embedded cost of service study. The total cost, or revenue requirement, by class provides a basis for determining the fair and reasonable level of revenues that need to be obtained from each class of customers.

AE's CCOS follows the fully-distributed embedded cost of service methodology described above. AE's plant costs are functionalized on Schedules B-1 through B-12 and expenses are functionalized on Schedules D-1 through D-5 and E-1 through E-6. Schedules F-1 through F-6 develop the functionalization and allocation factors that are employed throughout AE's CCOS. The previously functionalized and classified costs are further broken down into more detailed sub-functions to provide for greater accuracy and detail on Schedules G-1 through G-5. Finally, the detailed costs are allocated to customer classes as shown on Schedules G-6 and G-7, and summarized on Schedules G-8 through G-10. Schedule G-10 recaps the total revenue requirements by class and summarizes the differences between present and proposed rates as well as the costs of providing service by class.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING AE'S CCOS?

A. Yes, I have several recommendations. I recommend that Production-related costs be allocated on the basis of the Four Coincident Peak Average and Excess ("4CP/A&E")[5] demand methodology, consistent with other summer peaking electric utilities in Texas. This method is also consistent with AE and ERCOT planning and operating guidelines as well as with the distinctly summer peaking nature of AE's system load. I also recommend that primary and secondary substations, poles, and conductors be allocated on the basis of summer non-coincident peak ("NCP") demands rather than the sum of 12 months of NCP demands, as AE has proposed. Finally, I recommend that the revenue requirement of Service Area Street Lights not be allocated to other classes as set forth on Schedule G-7, line 40, and not be included in the Community Benefits pass through charge, but instead be established as a separate class with applicable base rate and other charges that are charged to the City of Austin for this service, consistent with other utilities in the Texas and with previous AE practice.

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[5] The A&E/4CP is referred to as "A&E 4CP" in Austin City Council Ordinance No. 20120607-055 dated June 7, 2012. Both acronyms refer to the same Average and Excess Demand 4 Coincident Peak allocation method. Austin, Tex., Ordinance No. 201220607-055, *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* (2012).

Q. PLEASE EXPLAIN WHY YOU HAVE RECOMMENDED A DIFFERENT PRODUCTION COST ALLOCATION METHOD THAN THAT PROPOSED BY AE.

A. AE has proposed to use the sum of 12 monthly coincident peak ("12CP") demands to allocate production-related costs to customer classes. In AE's *Tariff Package: 2015 Cost of Service Study and Proposal to Change Base Electric Rates* ("Tariff Package"), AE states on page 2-10 (Bates 022) that

> [i]n the current cost of service assessment, Austin Energy has allocated costs to customer classes using different allocation methods for different categories of costs. For each of those categories, the Costs of Service analysis applies the methodology approved by the City Council in 2013, with the exception of the allocator of generation production costs. For these specific costs, Austin Energy recommends using the ERCOT Twelve Coincident Peak (ERCOT 12CP) methodology. This is an appropriate methodology for a regulated entity like Austin Energy that operates in a centralized dispatched environment like the ERCOT Nodal Market.[6]

AE does not explain what it is about the ERCOT nodal market that makes the 12CP methodology an appropriate methodology. Further, on page 5-11 (Bates 114) of the Tariff Package, AE states

> [f]or the production function, AE is concerned with making generation available during the ERCOT system peak throughout the year; therefore, to allocate demand costs to each customer class, Austin Energy calculates each customer class' contribution to the twelve monthly peak days that occur from January through December.[7]

[6] *Austin Energy's Tariff Package: 2015 Cost of Service Study and Proposal to Change Base Electric Rates* at 2-10 (Bates 022) ("Tariff Package").

[7] *Id.* at 5-11 (Bates 114).

This appears to be a disingenuous argument. Insofar as AE is concerned with ERCOT system peak demands, AE's concern should lie solely within the summer months as that is when ERCOT peak demands occur. That is precisely what ERCOT uses for its own system peak planning. Because peak demand occurs during the summer months, it does not follow that demands during non-summer months are the cost drivers of production costs.

AE's primary support for the use of the 12CP method is provided on pages 5-14 (Bates 117) and 5-15 (Bates 118) of the Tariff Package. AE states

> [the 4CP/A&E] methodology allocates production expenses to customer classes in proportion to class contribution to the system peak demand in each of the four summer months. This methodology is more applicable to vertically integrated utilities which dispatch their own generation resources to serve their own load.[8]

Again, AE provides no explanation of why the 4CP/A&E methodology, used by the unregulated, unbundled, and centrally dispatched ERCOT market is more applicable to vertically integrated, self-dispatching electric utilities, or why the 12CP methodology is preferable for a summer peaking utility operating in a summer peaking power pool. The fact that AE's power plants are centrally dispatched by ERCOT does not mean that demands during off peak months are the drivers that result in the need for additional power supply resources. In fact, the opposite is true – capacity additions are generally needed in ERCOT during peak months to insure that there is sufficient generation to meet peak demands during the summer.

[8] *Id.* at 5-14 (Bates 117) and 5-15 (Bates 118).

AE suggests that since the advent of the ERCOT nodal market AE has "opportunities to use its entire fleet throughout the year, not just during the peak demand season." As a result,

> Austin Energy proposes to use the ERCOT 12 Coincident Peak (ERCOT 12CP) methodology to functionalize the cost of generation because this allocation methodology better aligns the relationship between the costs and the benefits that accrue from owning and operating its fleet.[9]

AE's support for the 12CP methodology seems to rely upon its statement "that all of AE's customers benefit from AE's generation fleet year round." AE has chosen to use a 12CP allocation for demand-related production plant relying upon the mistaken reasoning that benefits of service rather than the costs of service should be the basis upon which rates are based.

Q. DO YOU AGREE WITH AE'S JUSTIFICATION AND USE OF THE 12CP PRODUCTION ALLOCATION METHOD?

A. No, I do not agree.

Q. PLEASE EXPLAIN WHY YOU DO NOT AGREE WITH AE'S USE OF THE 12CP ALLOCATION METHOD TO ALLOCATE PRODUCTION PLANT.

A. AE bases its justification for the use of the 12CP method exclusively upon the emergence and operating of the ERCOT nodal market. However, cost allocations should be based upon cost drivers, not customer benefits as AE has suggested. *A CCOS is a **cost** of service study, not a **benefits** of service study.* The fact that power supply resources are bid into the ERCOT nodal market does not suggest that peak summer demands have

[9] *Id.*

become less important and are no longer the drivers of production requirements. The ERCOT nodal market captures the efficiencies of coordinated production resources over a broader geographic area than AE's service territory, but it does not change the fundamental nature of production plant nor the importance of summer demands in Texas. In contrast, the use of 4CP/A&E is supported by the following:

- AE's own system planning and demand side management programs continue to reflect the importance of AE's demands during the summer;
- ERCOT's system planning and operation continue to recognize the importance of summer peak demands;
- *Just like the broader ERCOT system, AE's system is a distinctly summer peaking system with little likelihood that demands during other months of the year will influence AE's capacity requirements*;
- The 4CP/A&E methodology, not the 12CP methodology is supported by the PUC in electric utility rate cases; and,
- The National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual recommends the use of the 12CP allocation method only when the monthly peaks lie within a narrow range, which is not the case with ERCOT or AE; and
- The 4CP/A&E methodology was specifically approved by the Austin City Council in Ordinance No. 20120607-055, dated June 7, 2012, and there have been no changed circumstances in AE's operations, identified by myself or AE, since that time that would lead to a change in allocation methods.

Q. PLEASE EXPLAIN HOW ERCOT'S AND AE'S PLANNING AND OPERATIONS SUPPORT THE USE OF A SUMMER PEAK BASED ALLOCATION APPROACH SUCH AS THE 4CP/A&E METHOD.

A. ERCOT requires that the utilities in Texas maintain an adequate supply of electric generation to meet demand and maintain capacity reserves to help support grid reliability. As part of its system reliability function, ERCOT undertakes periodic Seasonal Assessment of Resource Adequacy ("SARA") to insure that the ERCOT region has sufficient "installed capacity to serve forecasted peak demands in the upcoming **summer season** (June – September 2016)" (emphasis added).[10] In addition, ERCOT generation reserve margins are expressed in terms of **summer demands**. For example, an ERCOT news release dated December 1, 2015, stated

> [t]he updated 10-year Capacity, Demand and Reserves (CDR) report released today by the Electric Reliability Council of Texas (ERCOT) shows a continuing rise in planning reserve margins in coming years, due primarily to the anticipated addition of more than 5,000 megawatts (MW) of new generation capacity by the summer of 2017 and another 4,300 MW the following year.[11]

This news release also stated that

> [t]he anticipated peak demand for electricity — forecast at more than 70,500 MW in summer 2016 and growing to nearly 78,000 MW by summer 2025 — also has increased from previous reports.

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[10] *See* Electric Reliability Council of Texas, *Preliminary Seasonal Assessment of Resource Adequacy for the ERCOT Region (SARA) Summer 2016*, Mar. 1, 2016, at 1 *available at* http://www.ercot.com/content/gridinfo/resource/2016/adequacy/sara/SARA-PreliminarySummer2016.pdf.

[11] *See* Press Release, Electric Reliability Council of Texas, New generation resources drive up projected ERCOT reserve margins through 2025 (Dec. 1, 2015), (http://www.ercot.com/news/press_releases/show/81272).

> The revised long-term load forecast continues to be based on a new forecasting methodology that was implemented in 2014.[12]

Finally, ERCOT's *2015 Annual Report of Demand Response in the ERCOT Region* addresses Transmission and Distribution Service Provider ("TDSP") load management programs. The report notes that "[e]ven though there are some minor variations in these programs generally all Load Management Programs require participants to be available only during weekdays from June 1 through September 30 and between the hours of 1 and 7 p.m."[13] Thus, while ERCOT focuses upon insuring adequate transmission capability during the summer and employs the 4CP approach in determining its "Postage Stamp Rate" for transmission, it also considers the four summer months of June through September as the months that are *most important* in terms of adequacy of generation capacity.

AE's power supply needs are also focused primarily upon customer loads during the summer months of June through September, and not upon loads throughout the year. AE's Tariff Package states

> [w]hile one typically considers the summer months to be the most costly due to the highest levels of demand – and on average that is correct – dramatic price excursions tend to occur in the winter and spring when weather variations are more extreme and when generating companies typical [sic] perform routine maintenance on their plants.[14]

[12] *Id.*

[13] *See* Electric Reliability Council of Texas, 2015 Annual Report of Demand Response in the ERCOT Region, Mar. 15, 2016, at 5 (http://www.ercot.com/services/programs/load).

[14] Tariff Package at 3-15 (Bates 044), ln. 44.

The report further notes that "[i]n FY 2014 alone, the energy efficiency programs reduced Austin Energy's peak demand by 67 MW."[15] The peak demand referenced is the summer peak demand. The report lauds AE's energy conservation programs that allow the utility to remotely control customers' thermostats, allowing AE to cycle off customers' air-conditioning load.[16] Additionally, AE's "Powersaver" program focuses on control of summertime air-conditioning and not winter heating. This is not unexpected since "Austin Energy's energy conservation goals reduce the amount of customer demand during summer peak periods…." "[T]the highest average wholesale market prices tend to occur during the hot summer months and Austin Energy's demand side management programs directly lower demand for electricity during those summer peak hours."[17] AE's own planning and operations recognize that summer peak demands have a far greater impact upon production requirements than do non-summer demands.

Q. IS THE FACT MANY GENERATION COMPANIES TYPICALLY PERFORM MAINTENANCE DURING NON-PEAKING MONTHS AFFECT YOUR ANALYSIS?

A. No, my analysis does not change. Planned maintenance is generally scheduled to occur during the time of year when demands are lowest in order to minimize the likelihood of outages resulting from lack of generation capacity. It would not be reasonable or prudent to schedule generation maintenance during the times of year when the generation is most needed.

[15] *Id.* at 3-40 (Bates 069).

[16] *Id.*

[17] *Id.* at 3-39 (Bates 068).

Q. HAVE YOU ANALYZED AE'S MONTHLY SYSTEM PEAK DEMANDS TO DETERMINE WHETHER THE SUMMER PEAKS ARE SIGNIFICANTLY HIGHER THAN THE SYSTEM PEAKS DURING THE OTHER MONTHS OF THE YEAR?

A. Yes, I have and the results of my analysis are provided in Exhibit GLG-3. My analysis demonstrates that AE's peak demands during the summer are significantly different (higher) than the system peak demands during non-summer months.

Q. PLEASE DESCRIBE THE ANALYSIS YOU HAVE CONDUCTED.

A. I have employed 11 years of monthly AE system peak demands on pages 1 through 5 of Exhibit GLG-3 and 10 years of monthly AE system contributions to the ERCOT system peak demand on pages 6 through 10 in this analysis. The results of each study lead to the same conclusion, AE is a distinctly summer peaking electric system in which there is *virtually no likelihood of a system peak occurring during any month other than June through September*. Indeed, during 8 of 11 years AE provided system peak demand, the AE system peak demand occurred in August. Similarly, during 8 of 10 years for which AE provided system contributions to the ERCOT system peak demand, AE's contribution to the ERCOT peak also occurred during the month of August. In addition, the months of June through September were the only months in which the peak demands were within 90% of the system peak demand. This shows AE is a summer peaking electric system and, therefore, should utilize a 4CP approach instead of a 12CP approach, as AE has proposed.

I also analyzed the monthly peak demand data from a statistical perspective. At a 90 percent confidence level one must reject the hypothesis that the months other than June through September are not significantly different than the annual system peak. In other words, only the demands during the months of June through September are statistically the same as the system peak demand, while system demands during other months of the year are statistically different that the annual peak demand at a 90 percent confidence level.

Q. YOU EARLIER STATED THAT THE NARUC <u>ELECTRIC UTILITY COST ALLOCATION MANUAL</u> DOES NOT RECOMMEND THE USE OF THE 12CP ALLOCATION METHOD EXCEPT WHEN THE MONTHLY PEAKS LIE WITHIN A NARROW RANGE. PLEASE EXPLAIN.

A. In its discussion of peak demand allocation methods, the NARUC Electric Utility Cost Allocation Manual states

> [t]his [12CP] method uses an allocator based on the class contribution to the 12 monthly maximum system peaks. This method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky. The 12-CP method may be appropriate when the utility plans its maintenance so as to have equal reserve margins, LOLPs, or other reliability index values in all months.[18]

AE's monthly peaks do not lie within a narrow range, but instead exhibit much higher loads during the summer months than during other months of the year. In other words, AE's load shape is spiky. Therefore, AE's use of the 12CP allocation methodology is

[18] National Association of Regulatory Utility Commissioners, ELECTRIC UTILITY COST ALLOCATION MANUAL, 46 (1992).

contrary to the recommendations of NARUC, a recognized authority, and should be rejected, for all reasons explained above.

Q. IS THE 4CP/A&E DEMAND ALLOCATION METHOD A METHOD THAT HAS BEEN ACCEPTED BY THE PUC?

A. Yes. The PUC approved the use of the 4CP/A&E production allocation method in Docket No. 43695, *Application of Southwestern Public Service Company for Authority to Change Rates*. Additionally, in Docket No. 40443, *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, the PUC specifically rejected Southwestern Electric Power Company's proposal to use the 12CP allocation method, stating "SWEPCO is a summer peaking utility. The electricity demands in the spring and fall months are much lower and not relevant in determining the amount of capacity needed for SWEPCO to provide reliable service."[19] The PUC further found that "[t]he June through September summer peak demands determine the amount of transmission capacity that SWEPCO must build. SWEPCO's use of the 12CP method is *inconsistent with cost causation*" (emphasis added).[20] Finally, in Finding of Facts 282 and 286 of the same Order the PUC accepted SWEPCO's use of the 4CP/A&E for the allocation of production costs.

In addition, the PUC has upheld the use of the 4CP/A&E method in Docket No. 39896, *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, and found:

[19] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443, Finding of Fact No. 268 (Oct. 10, 2013).

[20] *Id.* at Finding of Fact No. 269 (Oct. 10, 2013).

> 183. The Average and Excess (A&E) 4CP method for allocating capacity-related production costs, including reserve equalization payments, to the retail classes is a standard methodology and the most reasonable methodology.[21]

Finally, in PUC Docket No. 40627, AE's recent case before the PUC, PUC Staff witness, William Abbott recommended that the Commission adopt the standard 4CP/A&E allocation methodology.[22] Although the case was settled, the fact that the PUC Staff recommended the use of the same method I propose for AE is important in gaining insight as to the appropriate allocation method recommended by an objective cost allocation expert.

In summary, I have reviewed the PUC's decisions regarding the allocation of production costs and found no instances, in recent history, in which the 12CP method was accepted to allocate costs to customer classes, and there is at least one instance in which the method was outright rejected.

Q. IS THE 4CP/A&E DEMAND ALLOCATION METHOD A METHOD THAT HAS BEEN ACCEPTED BY THE AUSTIN CITY COUNCIL?

A. Yes. Part 6 of City of Austin Ordinance No. 50120607-055, passed and approved on June 7, 2012, states "[t]he Council adopts as policy the use of the A&E 4CP methodology to allocate production demand costs among customer rate classes." Although AE has previously stated it must follow the Austin City Council's directives with respect to financial policies, they have not followed the City Council's directive related to cost

[21] *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment,* Docket No. 39896, Finding of Fact No. 183 (Sept. 14, 2012).

[22] *Petition by Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-055*, Docket No. 40627, Direct Testimony of William B. Abbott at 14 (Feb. 14, 2013).

allocation. AE has instead chosen an alternative methodology, to the detriment of customers and contrary to PUC policy.[23]

The ERCOT nodal market was fully operational well before the date that the Austin City Council adopted the A&E 4CP methodology to allocate production demand costs among customer rate classes. Consequently, there are no changed circumstances, identified by AE or myself, since the date the ordinance was approved that would lead AE or the IHE to reject the Council's previous approval of the A&E 4CP methodology. In light of the fact AE continues to argue it must follow "Council's directives" as related to other issues, it should follow this clear directive of Council and the PUC with respect to cost allocation. AE's proposed use of the 12CP allocation methodology is contrary to established Austin City Council policy and should be rejected by the IHE. In contrast, NXP and Samsung's recommended use of the 4CP/A&E cost allocation methodology is consistent with Council policy and should be approved as the basis for allocating demand-related production costs.

Q. BASED UPON THE ABOVE TESTIMONY, WHAT METHOD FOR ALLOCATING DEMAND-RELATED PRODUCTION COSTS DO YOU RECOMMEND BE APPROVED FOR AE?

A. I recommend that the IHE approve the 4CP/A&E demand method to allocate production demand costs and that AE's proposed 12CP production allocation method be rejected. The 4CP/A&E allocation method is consistent with AE planning and operations, is

[23] I note PUC precedent because this case is likely to be appealed to the PUC and, therefore, whenever PUC precedent can be applied it should be applied because that is the precedent that will likely be applied upon appeal.

consistent with ERCOT planning and operations, reflects the distinctly summer peaking characteristics of AE's system, is consistent with NARUC guidelines, has been approved by this state's regulatory authority for use for other similarly situated electric utilities, and has been approved for use by the Austin City Council.

Q. HOW HAS AE ALLOCATED THE COSTS OF SUBSTATIONS, POLES, AND CONDUCTORS IN ITS CCOS?

A. On Schedule G-6, AE has allocated Primary and Secondary substations, poles, and conductors, and the associated indirectly allocated costs, on the basis of 12 non-coincident peak ("12NCP") demands. AE's support of using non-coincident peak ("NCP") demands to model the impact of customer loads upon distribution facilities is addressed on page 5-11 (Bates 114) of its Tariff Package, which states

> [t]he distribution function is concerned with meeting localized demands; therefore, class maximum demands are often used to allocate distribution costs. Finally, for individual customers, AE is concerned with the maximum demand that the specific customer places on the system. These demands are significant cost drivers for AE's capital expenses, including debt.[24]

AE's only mention of the use of the sum of 12 NCP demands (i.e., the 12NCP allocation method) is provided on pages 5-16 and 5-17 (Bates 119 and 120), which states

> [t]he 12NCP method takes the average of each class' NCP for all 12 months. This method represents the annual average class peak and was used to allocate costs associated with distribution load dispatch, distribution substations, poles, and conductors at both the primary and secondary voltage levels.[25]

[24] Tariff Package at 5-11 (Bates 114).

[25] *Id.* at 5-16 to 5-17 (Bates 119-120).

However, nowhere does AE provide an explanation that supports its use of the 12NCP method to allocate distribution substations, poles, and conductors.

Q. DO YOU AGREE THAT NCP DEMANDS ARE THE CORRECT DEMAND MEASURE TO EMPLOY IN THE ALLOCATION OF THIS DISTRIBUTION PLANT?

A. Yes, I do. Non-coincident peak demands reflect the diversity of individual demands that influence the design of the distribution network. However, I do not agree that the sum of 12 monthly NCP demands is the appropriate allocation method to assign these costs.

Q. PLEASE EXPLAIN WHY YOU DISAGREE WITH AE USING THE SUM OF 12 NCP DEMANDS TO ALLOCATE SUBSTATIONS, POLES, AND CONDUCTORS.

A. There are several reasons why I disagree with AE's use of the sum of 12NCP demands to allocate substations, poles, and conductors. First, the operating efficiency and capacity of substations, transformers, and conductors is highly temperature sensitive, which results in greater amounts of equipment capacity being required during the hot summer months in order to meet a similar load occurring during the coldest times of the year; higher ambient temperatures reduce the operating efficiency and capacity of distribution equipment. Conversely, lower ambient temperatures allow substations, transformers, and conductors to operate more efficiently and provide improved load carrying capabilities. Thus, a kilowatt of demand placed upon distribution equipment during the summer has a much greater impact upon equipment capacity than occurs during the winter when temperatures are substantially lower.

In addition, as reflected in AE's distribution planning process, AE recognizes the greater importance of summer demand. In its Tariff Package, AE stated:

> [t]he [distribution] planning process begins with a review of distribution system performance during the previous summer's peak load periods. Overhead distribution feeder circuits and substation transformers are noted for further study when their loading reaches 85 percent of their normal rating under normal (i.e. all facilities in service and all loads being served) conditions.[26]

AE also states that the feeder modeling software used to analyze the distribution system uses summer load conditions "[t]o ensure model accuracy, they [AE distribution planners] first match and then test the previous summer's system configuration and peak load conditions."[27]

Because temperatures during the non-summer months are much lower than during the hot summer peak months, the impacts of NCP demands is far less during these times of colder temperatures. Effectively, customer demands placed upon this distribution equipment during the high temperature, summer peak periods, impact the capacity requirements of the substations, transformers, and conductors more than during cooler months. Therefore, customers' NCP demands during other periods do not drive the costs of this distribution equipment and should not be employed for purposes of cost allocation.

Q. WHAT IS THE IMPACT UPON THE COST OF SERVICE STUDY RESULTS WHEN SUMMER NCP DEMANDS ARE EMPLOYED TO ALLOCATE SUBSTATIONS, POLES, AND CONDUCTORS?

A. The impact upon the CCOS results when summer NCP demands are employed to allocate

[26] *Id.* at 3-32 (Bates 061).

[27] *Id.*

substations, poles, and conductors cannot be determined using the CCOS model that AE originally provided. AE provided a "locked" model that did not allow users to answer this question using AE's model; only those allocation factors that AE has chosen to include in the model could be used to assign costs.[28] Using the monthly NCP class load data provided in AE workpaper WP F 6.1, which provides class NCP demands by month, to develop a summer NCP allocation factor (i.e., the sum of NCP demands during June through September) indicates that too much cost has been allocated to some classes such as Primary Service >= 20 mW and Secondary < 10 kW while too little costs has been allocated to other classes such as Residential. Using the summer NCP demands from AE workpaper WP F-6.1, I have recalculated the correct allocation factors for primary and secondary allocations and employed the 4NCP allocation factor rather than the 12NCP allocation factor to allocate the costs of distribution substations, poles, and conductors. A summary of the results is provided on Exhibit GLG-4, page 2 of 2, lines 64 through 71.

IV. CLASS REVENUE DISTRIBUTION

Q. GENERALLY DESCRIBE AE'S PROPOSED DISTRIBUTION OF THE CHANGE IN REVENUES TO EACH CUSTOMER CLASS.

A. AE's revenue requirement model sets forth total present and proposed revenue and costs of service by class, including pass through adjustments (Schedule G-10 of its CCOS model). A comparison of cost of service and present and proposed base rates by class is

[28] A protective order would have allowed the parties, including NXP / Samsung, to fully utilize AE's revenue requirement and class cost of service model. However, as filed, AE's model includes large amounts of hidden data, limited flexibility in allocation changes, limited flexibility in changing input values, and is password protected to prevent users from modifying the model to undertake a more complete analysis of AE's information. This lack of transparency and model inflexibility should be corrected in future filings.

provided in workpaper WP G-10.2, and proposed class revenues from adjustment clauses is set forth in Schedule G-7. AE has proposed to not increase the rates for any class of customers, except for the Transmission service class, as part of its proposed rate decrease. The Transmission service class, according to AE, is required by tariff to be set at its costs of service. AE has stated its "proposed customer revenue requirement was developed with an underlying objective that no customer class incur a revenue increase, taking into account proposed base rate adjustments and forecasted pass through charges."[29] In addition, AE proposes to employ its proposed rate reduction to reduce those rates for the classes that are currently paying the most in terms of excess above their total costs of service. However, AE has done nothing to correct what it has itself referred to as "significant deviations from cost of service"[30] for the residential class.

Q. AE HAS RECOGNIZED THE NEED TO MOVE CLASS RATES TOWARD COSTS OF SERVICE, BUT HAS RECOMMENDED THAT THE MOVEMENT BE ADDRESSED IN FUTURE FILINGS. DO YOU AGREE?

A. No, I do not agree. Postponing the movement toward cost-based rates is neither fair nor reasonable. I also do not agree that "kicking the can down the road" is prudent or necessary. AE recommends that the existing subsidies continue for another five years without addressing the issue. Furthermore, AE has not indicated what its position with respect to rate design will be at that future time, nor if they will actually address the issue

[29] *Austin Energy's Tariff Package: 2015 Cost of Service Study and Proposal to Change Base Electric Rates*, Austin Energy's Response to the First Request for Information from NXP Semiconductors and Samsung Austin Semiconductor, LLC at 1-21 (Feb. 28, 2016).

[30] Tariff Package at 2-12 (Bates stamp 024).

in the future, or if AE will continue to allow a high degree of subsidization. Until the unreasonably large interclass subsidies are eliminated, economic efficiency will suffer, price discrimination will continue, and specific customers (including NXP, Samsung, and others) will be called upon to continue to support the costs of providing electricity to others. It is simply unfair and unreasonable to require the continued high subsidization of some customer classes by other classes, especially when there is no end in sight or commitment to work on bringing classes to cost of service. It is inappropriate to use electric delivery rates as the means to "tax" one class of customers for the benefit of another class of customers, as AE proposes.

Q. WHAT IS THE EFFECT OF THE INTERCLASS SUBSIDIES RESULTING FROM AE'S PROPOSED RATES ON CUSTOMER CLASSES THAT ARE ASKED TO PAY MUCH MORE THAN THEIR ACTUAL COST OF SERVICE?

A. From an economic perspective, AE's proposed revenue distribution is effectively a tax upon specific customer classes for the benefit of other classes, i.e., a hidden "utility tax."

Q. PLEASE EXPLAIN.

A. AE's proposed rates would employ the revenues produced by Secondary Voltage ≥ 10 < 300 kW, Secondary Voltage ≥ 300 kW, Primary Voltage < 3 mW, Primary Voltage ≥ 3 < 20 mW, Primary Voltage ≥ 20 mW, and Transmission Voltage customers to subsidize the costs of providing electricity to Residential, Secondary Voltage < 10 kW, Service Area Street Lighting, City-Owned Private Outdoor Lighting, Customer Owned Non-Metered

Lighting, and Customer-Owned Metered Lighting customers.[31] Stated another way, AE's proposed rates redistribute the costs of serving Residential, Secondary Voltage < 10 kW, Service Area Street Lighting, City-Owned Private Outdoor Lighting, Customer Owned Non-Metered Lighting, and Customer-Owned Metered Lighting consumers to other consumers in the form of a utility tax that the utility, for public relations purposes, refers to as a community benefit. Energy pricing is a poor method of taxing citizens.

In Principles of Public Utility Rates, Professor James Bonbright criticizes the use of regulation as a means of taxation, which is effectively what AE proposes. Dr. Bonbright's authoritative text addresses the concern as follows:

> … regulation is also sought as a clumsy vehicle for redistributing income and serves as an indirect form of taxation to achieve certain economic or social objectives. The regulating agency compels firms to provide a service that otherwise would not be provided, or to provide it at a below-cost subsidy level. Of course, other prices must be high enough to support the low-priced, unprofitable service. In this way, the government agency can require the regulated firm to overcharge (tax) those people the agency deems "less deserving" so that "more deserving" people can be undercharged (subsidized). The regulated firm is, in turn, granted a monopoly status, attained in some cases by preventing entry. Thus, through the covert regulatory process, redistributions can be attained that would be difficult or impossible through the overt and thoroughly examined budgets of the legislature.[32]

As stated in this frequently referenced authority, incorporating social policy into cost allocation and pricing through interclass subsidies is not the best means of cost allocation and pricing. Regardless of how AE portrays its recommendations regarding revenue distribution, the utility essentially recommends levying a tax upon certain classes

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[31] As a result of tariff requirements AE proposes to set the rates applicable to Transmission Voltage ≥ 29 mW @ 85% aLF equal to that class' cost of service.

[32] James C. Bonbright, Albert L. Danielsen & David R. Kamerschen, PRINCIPLES OF PUBLIC UTILITY RATES 55 (2d ed. 1988).

of customers in order to redistribute the income from those classes to other customer classes. It is no more appropriate to tax those customers who have no say in this income redistribution than it is to tax Austin residents for what is effectively a self-serving "public relations" policy. It is not appropriate to ignore the rates charged to customer classes whose present revenue levels are already lower than their allocated costs of service. Such a reduction exacerbates the already unfair cross-subsidization that is currently taking place. AE's proposed increases and decreases by class should be denied by the IHE, and an immediate movement to cost-based rates should be approved and implemented in the current proceeding.

Q. WHY SHOULD THE CROSS-SUBSIDIES THAT EXIST IN AE'S CURRENT RATES BE CORRECTED IN THIS RATE REVIEW INSTEAD OF BEING ADDRESSED IN FUTURE RATE REVIEWS, AS AE HAS PROPOSED?

A. As stated above, AE has simply "kicked the can down the road," forcing commercial and industrial customers to continue to subsidize the significant losses AE faces as a result of its proposed Residential, small commercial, and lighting rates, which are far below the cost of providing service. Such a proposal is unreasonably preferential and discriminatory. Furthermore, it is likely that failure to correct the enormous inequities in rate design, as recognized by AE, in this rate review, in which rates are being reduced, will only exacerbate the problem in future rate reviews when AE proposes to increase rates. If classes are brought to cost of service when a rate increase is proposed, those classes that are subsidized more will see a greater share of that increase. The current rate review provides a window of opportunity to correct problems with little or no adverse impact upon customers. This situation is unlikely to reoccur in future rate reviews. Correcting the existing cost of service inequities during a future rate review in which AE's overall revenue requirement is being increased will only make the objective of cost based rates more difficult to attain and will result in significantly larger increases than would otherwise occur. For these reasons, the current rate review is the time to correct the existing rate inequities which will likely only get worse over time.

Q. DOES THE HIGH SUBSIDIZATION OF THE RESIDENTIAL CLASS AFFECT ENERGY EFFICIENCY IN ANY WAY?

A. Yes, when customers, especially Residential Customers, are below the cost of service they do not have the proper incentives and price signals to conserve energy in the same manner they would if they were being charged full cost of service. Economic efficiency, which is the best and highest use of resources, occurs when consumers are able to weigh the costs of additional consumption of energy and power with the benefits received from that additional consumption. Under-charging for energy leads to excessive use of energy, which should be discouraged.

Q. OTHER THAN COST OF SERVICE CONSIDERATIONS, WHAT OTHER FACTORS DO YOU BELIEVE SHOULD BE CONSIDERED WHEN DETERMINING THE DISTRIBUTION OF AE'S REVENUE REQUIREMENT AMONG CUSTOMER CLASSES?

A. For large industrial customers such as NXP and Samsung, competitive pressures should also be considered in setting rates. The Austin City Council recognized the importance of competition when setting its Affordability Goal. On February 17, 2011, Austin City

Council Passed Resolution 20110217-002, implementing the *Austin Energy Resource, Generation, and Climate Protection Plan to 2020*, including an affordability goal. The Agenda Late Backup papers associated with this resolution state

> [t]he affordability goal, intended to make the Resource Plan as predictable as possible, calls for Austin Energy to operate so as to control all-in (base, fuel, riders, etc.) rate increases to residential, commercial and industrial customers to 2% or less per year. In addition, the goal is to maintain AE's current all-in competitive rates in the lower 50 percent of Texas rates overall.[33]

However, AE has not proposed to apply these affordability goals uniformly among customer classes, but has instead consistently underpriced Residential service at the expense of Commercial and Industrial service. AE's September 24, 2015 presentation to the City Council, "Austin Energy – Investing in a Clean Future", compares the AE price of energy by class to the statewide price of energy. The table below provides the data set forth on page 9 of that document.

2013 Average Texas Electricity Price by Customer Class (cents/kWh)

	Residential	Commercial	Industrial	Total
Austin Energy	11.09	10.03	6.88	9.66
Texas Average	11.35	8.02	6.36	8.98
Ratio of AE to TX Average	97.71%	125.06%	108.18%	107.57%

[33] 20110217-002, Agenda Late Backup, *available at http://www.austintexas.gov/content/february-17-2011-austin-city-council-regular-meeting* (Feb. 17, 2011); Austin, Tex. Resolution 20110217-002 (Feb. 17, 2011); Austin, Texas Resolution No. 20140828-157 (Aug. 28, 2014) (reaffirming the City Councils February 17, 2011 directive).

2014 Average Texas Electricity Price by Customer Class (cents/kWh)

	Residential	Commercial	Industrial	Total
Austin Energy	11.31	10.41	7.00	9.96
Texas Average	11.80	8.12	6.17	8.96
Ratio of AE to TX Average	95.85%	128.20%	113.45%	111.16%

2015 Average Texas Electricity Price by Customer Class (cents/kWh)

	Residential	Commercial	Industrial	Total
Austin Energy	10.89	9.92	6.49	9.49
Texas Average	11.84	7.93	5.65	8.72
Ratio of AE to TX Average	91.98%	125.09%	114.87%	108.83%

Note that during the past three years AE's Residential rates as a percentage of the Texas average price of electricity have declined in every year, averaging between 92% and 98% of the statewide average. In contrast, AE's Commercial price of electricity has remained over 25% higher than the Texas average and Industrial rates averaged between 8% and 11% higher than the statewide average. In other words, AE has ignored affordability goals when setting rates for Commercial and Industrial classes and has placed its Commercial and Industrial customers at a competitive disadvantage to similarly situated electricity consumers around Texas.

A review of a TXU Energy invoice for a large industrial primary voltage customer in competitive service areas in Texas indicates that high load factor industrial customers located elsewhere in Texas pay rates less than 5.1 cents per kWh as compared to AE's proposed total rate of 6.3 cents per kWh.[34] This 24% disparity imposes a very real economic disadvantage to large, energy intensive consumers such as NXP and Samsung. The rates charged to AE's large customer classes, such as Primary ≥ 20 MW, are disproportionately out of alignment with the Texas market. Such rates are unreasonably preferential to Residential customers and unduly discriminatory toward Commercial and Industrial customers, potentially resulting in some large commercial or industrial customers choosing to locate outside of AE's service territory, thus not providing the City of Austin with that new business opportunity.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE DISTRIBUTION OF AE'S REVENUE REQUIREMENT BY CUSTOMER CLASS?

A. I recommend that the rates for all customer classes be moved to full cost recovery in this rate review. As I have previously testified above, because this review involves a rate reduction rather than a rate increase, the impact of correcting the severe subsidization of customer classes will be far less at this time than in future rate reviews involving rate increases. Stacking movement toward cost based rates on top of a rate increase will result in far more drastic customer impact concerns than will occur by correcting the problem today. My proposed distribution of Ms. Fox's proposed revenue requirement is provided in Exhibit GLG-4, page 1 of 3, lines 10 through 17. As indicated on Exhibit GLG-4, page 1 of 3, lines 19 through 26, with Ms. Fox's recommendations and my

[34] Primary ≥ 20 MW Proposed Rates with Estimated Pass-Through Costs = $82,731,148 per AE Schedule G-10, line 18, column (H). For the same class, kWh sold = 1,305,530,321 per AE Schedule F-6, line 25. $82,731,148 ÷ 1,305,530,321 = $0.0634/kWh.

recommendations combined, all classes, except Service Area Street Lighting and City-Owned Private Outdoor Lighting, receive decreases to total electric costs. Also as indicated on Exhibit GLG-4, page 1 of 3, lines 19 through 26, base rate increases are required for each of AE's four Lighting classes. It is noteworthy that with my recommendations and those of Ms. Fox, Residential base rates will decrease by almost \$6.7 million and total Residential revenues from all sources will decline by \$31.5 million. Base rate revenue from Secondary voltage customers will decrease by \$108 million, Primary voltage customers' base rates will decrease by \$24.3 million, Transmission voltage customers' base rates will decrease by \$1.1 million, and Lighting services base rates will increase by \$7.6 million. Table 1 below summarizes my recommended change in revenues.

Table 1

NXP/Samsung Rate Changes	Residential	Secondary	Primary	Transmission	Lighting	Total
Base Revenue	(\$6,676,868)	(\$108,041,514)	(\$24,272,357)	(\$1,127,794)	\$7,572,538	(\$132,545,995)
Recoverable Fuel	(24,187,365)	(31,163,142)	(13,144,234)	(1,407,131)	1,097,277	(68,804,595)
Green Choice	0	0	0	0	0	0
Community Benefit	(5,013,172)	(4,700,111)	(1,598,668)	(130,984)	239,779	(11,203,156)
Regulatory	4,337,620	4,153,481	1,357,184	119,421	25,254	9,992,960
Sub-total Pass Through Charges	(\$24,862,917)	(\$31,709,771)	(\$13,385,717)	(\$1,418,694)	\$1,362,310	(\$70,014,790)
Total Proposed Revenue Change	(\$31,539,785)	(\$139,751,285)	(\$37,658,074)	(\$2,546,488)	\$8,934,847	(\$202,560,785)

There are no customer impact concerns such as rate shock that necessitate a more gradual movement to each class fully recovering its allocated cost of service. If classes are moved to cost of service at this time in this rate review, there will be far less concern in the future for this issue.

Q. DOES YOUR PROPOSAL BRING ALL CLASSES TO FULL COST OF SERVICE?

A. Yes, it does. In my opinion, requiring all class to pay rates that reflect the full cost of providing service is fair and reasonable, and the present rate review offers a window of opportunity to correct the unreasonable level of interclass subsidies that currently exist. Failure to move classes to cost based rates in this current rate review will exacerbate the problem in future rate increase filings by AE resulting in greater rate shock issues at that time.

V. SERVICE AREA STREET LIGHTING

Q. AE HAS PROPOSED TO RECOVER THE COSTS OF SERVICE AREA STREET LIGHTING ("SASL") THROUGH THE COMMUNITY BENEFIT CHARGE RATHER THAN THROUGH THE APPLICATION OF BASE RATE CHARGES REFLECTING THE COSTS OF PROVIDING THIS SERVICE. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No, I do not agree.

Q. PLEASE EXPLAIN WHY YOU DO NOT AGREE WITH AE'S RECOMMENDATION.

A. AE has proposed to recover the costs of SASL by means of an automatic adjustment provision applied on the basis of kWh sales. I have three concerns about this proposal. First, SASL is a non-utility service, which should not require a subsidy from the City of Austin's electricity consumers. It is neither fair nor reasonable to compel electricity users to pay for a service over which they have little or no control and perhaps no need; a service provided by the City of Austin that is utilized by more than just AE customers who live within the City limits.[35] By eliminating the link between the cost of providing service and what customers pay for the service, neither AE nor those customers benefiting from the service have an incentive to make prudent and economically efficient decisions regarding where lighting occurs, or the costs of such lighting. If the costs of SASL are not a factor in determining the type and extent of the service provided, there is no economic incentive for AE to be prudent in its efforts to provide this service.

Second, the mechanism for recovering the costs of SASL will inevitably result in AE recovering a different level of costs than actually occurs. That is, the test year costs of providing SASL will be recovered on a per kWh basis even though the actual costs of providing this lighting service have nothing to do with the kWh sales to customers. Thus, as kWh sales to other customers increase beyond test year levels, the revenue produced by the Community Benefit charge will increase by the same proportion. However, there is no evidence to demonstrate, nor is there reason to believe, that the costs of providing SASL will increase by the same percentage as kWh sales increase. This mismatch between cost of service and the revenue AE receives for providing this non-utility service renders AE's proposal both economically inefficient and unreasonably discriminatory.

Finally, recovering the costs of SASL by means of an automatic adjustment charge is effectively a "lighting tax" applied to all electric consumers regardless of the benefits received, the fairness of the tax, or consumer preferences. Customers are being

[35] PUC Docket 40627 only applied to environs customers, therefore, as noted in AE's Tariff Package, "[t]he charge for Service Area Lighting is assessed only to customers inside the City limits and is designed to cover the cost associated with providing street light service within the City of Austin." Tariff Package at 4-61 (Bates 090).

forced to pay for a non-utility service through a utility rate, the Customer Benefit charge. As explained above, this lighting tax is "a clumsy vehicle for redistributing income and serves as another indirect form of taxation to achieve certain economic or social objectives."[36] If the City believes these services are important then they should provide them and pay for them transparently through the city budget.

Q. HOW YOU RECOMMEND ADDRESSING THE ISSUE?

A. I recommend that SASL be treated like any other customer class, that is, cost based rates should be established for each type of service area street lighting service offered and charged to the City of Austin, the true customer. In this manner, (a) the benefits of lighting services can be objectively compared to the costs of such service, thereby providing the necessary economic incentive for prudent investment in lighting services; (b) electricity consumers will not be charged for services that they neither want nor from which they benefit; (c) electric rates will not be used to fund non-utility service; (d) a hidden tax on electricity consumers will be eliminated; and, (e) the mismatch between the costs of providing SASL and the revenues AE receives for this service will be eliminated.

VI. COMPARISON OF AUSTIN ENERGY AND ERCOT POWER SUPPLY COSTS

Q. HOW DO THE TOTAL POWER PRODUCTION COSTS OF AE COMPARE TO AE'S SETTLEMENT PRICES FROM THE ERCOT NODAL MARKET?

A. AE's power production costs are significantly higher than the AE's settlements prices for power supply costs in the ERCOT nodal market. According to my calculations, and

[36] James C. Bonbright, Albert L. Danielsen & David R. Kamerschen, PRINCIPLES OF PUBLIC UTILITY RATES 55 (2d ed. 1988).

using AE's proposed power production costs as set forth on Exhibit GLG-5, AE's total power production costs are 48.5% greater than the costs of an equivalent amount of power and energy solely from ERCOT. For customers receiving service under the Primary Voltage ≥ 20 MW rate class, AE's power supply costs are 39.5% greater than the costs of the same power purchased directly from the ERCOT wholesale power supply market. Using the adjusted revenue requirement proposed by Ms. Fox, AE's allocation of generation costs are 40.9% greater than comparable AE settlement price in ERCOT and are 28.3% higher for the Primary Voltage ≥ 20 MW rate class.

Q. HOW DOES AE OPERATE IN THE ERCOT MARKET?

A. As explained by AE in its Tariff Package (page 5-5, Bate 108)

> [t]he utility's variable operating costs are recovered through the sale of energy into the ERCOT wholesale market. Austin Energy then passes this revenue on to customers through the Power Supply Adjustment. However, revenues from sales into the ERCOT wholesale market are not treated as a recovery mechanism for the fixed costs associated with AE's generation. Instead, Austin Energy recovers these fixed costs through base retail rates assigned to its customers and the production function is used to appropriately assign the fixed operating costs to the appropriate customer classes.

Q. PLEASE EXPLAIN HOW GENERATORS BID INTO THE WHOLESALE MARKET.

A. As explained in AE's Tariff Package (page 3-13, Bate 42):

> In the ERCOT wholesale market, the ISO determines how much electricity is required to meet the demand of all ERCOT-located consumers (load) at least once every five minutes of every day of the year. Then, the operator determines the amount of resources that are available to meet that load. **Each generating company offers to sell energy from its generation resources to the market at a price that is typically consistent with their**

> **resources' marginal operating costs and operational limitations**. ERCOT takes each offer and stacks them in order from least cost to highest cost. Then, ERCOT selects the least number of resources required to meet the forecasted load for that next five-minute interval, starting with the lowest cost resource first. The price of the last resource needed to meet the forecasted load sets the price for all resources required in that five-minute interval. By attempting to minimize the operating costs of their resources in an effort to be selected to provide energy in the next five-minute interval, generating companies help improve the economic efficiency of the market, and load can be served with the lowest cost resources available, regardless of ownership.

AE further explains that they are competing with other generators like NRG, Calpine, and Luminant.

Q. DO THESE GENERATORS HAVE RETAIL CUSTOMERS WHO ARE PAYING FOR THE REMAINDER OF THE COST TO PRODUCE THE ELECTRICITY THAT IS SOLD INTO THE ERCOT MARKET?

A. No. The ERCOT wholesale market is designed such that all of the competitive generators must recover **100%** of their cost through sales or providing ancillary services in the wholesale market, thus they cannot recover costs in any other manner.

Q. WHAT ARE THE ECONOMIC IMPLICATIONS OF AE'S TREATMENT OF PRODUCTION COSTS?

A. AE is able to utilize the revenue from its captive retail customers to underbid competitive generators. As a result, AE uses its retail operations to subsidize its participation in the wholesale market to the detriment of the retail customers.

Q. WHAT DOES THIS MEAN TO AE'S RATEPAYERS AND NXP/SAMSUNG?

A. This excess of AE power production costs above the costs of power available directly from the ERCOT market translates in \$279.7 million per year of excess power costs that AE consumers are paying for power, using Ms. Fox's recommended revenue requirement. Primary Voltage $\geq$ 20 MW customers, who are subject to highly competitive market pressures, are paying approximately \$16.5 million per year more to AE than they would pay by purchasing their power on the ERCOT market directly.

Q. WITH RESPECT TO NXP AND SAMSUNG, WHAT IS THE IMPACT OF AE'S HIGHER THAN ERCOT COSTS OF POWER?

A. Based upon discussions with NXP and Samsung representatives, AE's high costs of power are seriously undermining the competitiveness of both companies in their respective markets. In addition, power supply costs available from other electric utilities in Texas are significantly lower than the costs of power from AE. Similar to customer impact concerns that are often voiced for Residential and Small Commercial customers, there is a significant customer impact of high electric bills upon large industrial customers that operate in highly competitive markets.

Q. WHY ARE AE'S COSTS TO SUPPLY POWER SO MUCH HIGHER THAN MARKET COSTS?

A. Because the IHE has ruled that fuel costs are not an issue that can be addressed in this rate review and because AE has objected to virtually all data requests relating to power plant characteristics, power plant operations, and wholesale power contracts, I cannot answer that question. However, one can only assume that AE's generation fleet is far less efficient than the ERCOT market in general, as shown by the fact that AE power production costs are significantly higher than the costs of power available directly from the ERCOT market.

Q. WHAT DO YOU RECOMMEND THE AUSTIN CITY COUNCIL DO TO ADDRESS THIS ISSUE?

A. I recommend that the IHE consider customer impact concerns with respect to the rates charged to Primary Voltage $\geq$ 20 MW rate class, and that the Austin City Council adopt this approach. Even with the "cost based" rate that I have proposed, the power supply costs are more than $16.5 million higher than a rate with a market based power supply adjustment. Customer impact concerns may be addressed by setting the rates for the Primary Voltage $\geq$ 20 MW rate class lower than the allocated costs of service, so that when all costs are considered this class is more likely to be at cost of service. In addition, I recommend that the Austin City Council direct AE to provide a full and complete explanation and evaluation of its power supply costs in future filings, including information regarding the large amount by which AE's power costs exceed the power costs of the ERCOT market. AE should provide to its governing body quarterly updates on its total power production costs compare to its settlement prices in ERCOT, so that the governing body can be well informed of any variations in cost. This will provide the Austin City Council with an effective tool to evaluate utility performance.

VII. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY AND YOUR RECOMMENDATIONS IN THIS PROCEEDING.

A. My testimony makes the following recommendations:

1. Allocate Demand-related production costs on the basis of the 4CP/A&E and reject AE's proposed 12CP allocation method;
2. Allocate Primary and Secondary distribution substations, poles, and conductors on the basis of class non-coincident peak demands occurring during the months of June through September rather than non-coincident peak demands that occur year round;
3. Use the most recent TCOS information from PUC Docket No. 45387 for purposes of adjusting transmission costs;
4. Eliminate or revise AE's unsupported and unduly discriminatory total system "Billing Adjustment" of approximately $3 million, to recognize the appropriate class specific billing adjustments;
5. Remove the costs of providing Service Area Street Lighting from the Community Benefit charge and establish a set of cost based rates applicable to this service;
6. Set class rate levels such that the rates charged to each class are equal to the costs of providing service to that class.
7. Require that the Austin City Council direct AE to provide an explanation and evaluation of its power supply costs in future filings, including information regarding the extent to which AE's power costs exceed the power costs of the

ERCOT market. I further recommend that AE provide to the Austin City Council and to the Electric Utility Commission quarterly updates comparing its total power production costs to its settlement prices in ERCOT.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Qualifications and Experience

Mr. Goble graduated from the University of Arkansas at Fayetteville in 1974 with a Bachelor of Science degree in Public Administration. In 1980, he received a Master of Business Administration degree from St. Edward's University in Austin, Texas.

Upon graduation from the University of Arkansas, and before attending St. Edward's, Mr. Goble was employed by the Arkansas Public Service Commission ("APSC") and held several positions with the staff, including Chief of the Rates Section and Interim Chief of the Finance Section. Mr. Goble's activities in these positions included developing and presenting staff analyses and testimony concerning cost allocation studies and rate design for electric, natural gas, water, and telephone utilities; ensuring utility compliance with APSC rate and tariff requirements; and providing supervision and management to staff financial analysts in the determination of utility cost of capital and capital structure.

In 1978, Mr. Goble accepted the position of Manager of Electric and Water Rates in the Economic Research Division of the Public Utility Commission of Texas. In this capacity, he was responsible for staff analyses, testimony, and activities concerning cost analysis, rate design, pricing strategies, tariffs, and econometric applications for regulated utilities.

In 1980, Mr. Goble was employed by Gilbert Associates, Inc. as a Management Consultant. He was promoted to Senior Management Consultant in March 1981 and to Principal Management Consultant in July 1981. In July 1981, he became Manager of Cost and Load Analysis in Gilbert Associates' Austin office. His responsibilities at this consulting firm included the duties and areas of expertise previously described, as well as management of projects and project teams working on behalf of utility clients.

Mr. Goble became a principal at Management Applications Consulting, Inc. ("MAC") at the time of its formation in May 1984. His experience at MAC included continued work in the electric and gas utility industry representing investor-owned utilities, electric cooperatives, and municipally-owned utility systems. His duties at

MAC included the duties and areas of expertise previously described above. Mr. Goble remained a principal at MAC from May 1984 until January 2006.

From January 2006 through March 2007, Mr. Goble was employed as a management consultant by R. J. Covington Consulting, LLC. While employed by this firm, he continued to provide consulting services similar to those previously described as well as work in the areas of business valuation, affiliate transactions, and revenue requirement adjustments in regulatory proceedings.

In April 2007 Mr. Goble returned to MAC as a managing consultant. His responsibilities and job duties at MAC are the same as those previously described.

Mr. Goble has previously submitted testimony before the Public Utility Commission of Texas, the Railroad Commission of Texas, the Arkansas Public Service Commission, the Louisiana Public Service Commission, the Public Service Commission of Wyoming, the New Hampshire Public Utilities Commission, the Public Service Commission of the State of Montana, the North Carolina Utilities Commission, the Public Service Commission of the State of Missouri, the New Mexico Public Regulation Commission, the Colorado Public Utilities Commission, the South Dakota Public Utilities Commission, and the Arizona Corporation Commission. In addition, he has provided formal rate presentations to a number of municipally-owned and cooperative electric utilities.

Mr. Goble is currently, or has in the past, been a member of the following organizations: Association of Energy Economics, Association of Energy Engineers, Association of Energy Services Professionals, American Statistical Association, NARUC Committee on Utility Billing Practices, and the NARUC Ad Hoc Committee on Section 133 of PURPA. During the past 42 years, Mr. Goble has made a number of presentations at various industry associations and trade groups.

Exhibit GLG-2
Page 1 of 1

NXP/Samsung Corrected Billing Adjustment

No.	Description	Reference	FY14 Actual Base Revenue	FY14 Calculated Base Revenue	Normalized Base Revenue Under Current Rates	Remove Street Lighting Revenue	Total Test Year Base Revenue - Col. (C) + (D)	Test Year Base Revenue With AE Billing Adj	AE Billing Adjustment	AE Billing Adjustment to Applicable Classes	Distribution of AE Billing Adjustment to Applicable Classes	NXP/Samsung Billing Adjustments	Test Year Base Revenue With AE Billing Adj
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	**Base Revenue**												
2	Residential		$259,698,895		$258,528,778	$0	$ 258,528,778	$ 257,323,175	$ (1,205,603)	(1,205,603)	(130,716)	(1,336,319)	$ 257,192,459
3	Secondary Voltage < 10 kW		34,398,482		19,177,623	0	19,177,623	19,088,191	$ (89,431)	(89,431)	(9,696)	(99,128)	$ 19,078,495
4	Secondary Voltage ≥ 10 < 300 kW		63,736,050		156,360,867	0	156,360,867	155,631,706	$ (729,161)	(729,161)	(79,058)	(808,219)	$ 155,552,648
5	Secondary Voltage ≥ 300 kW		190,321,384		116,762,083	0	116,762,083	116,217,584	$ (544,499)	(544,499)	(59,037)	(603,536)	$ 116,158,547
6	Primary Voltage < 3 MW		15,088,965		19,359,718	0	19,359,718	19,269,437	$ (90,281)	(90,281)	(9,789)	(100,069)	$ 19,259,649
7	Primary Voltage ≥ 3 < 20 MW												22,633,008
8	Primary Voltage ≥ 20 MW												34,142,129
9	Transmission Voltage												1,334,692
10	Transmission Voltage ≥ 20 MW @ 85% aLF												3,988,886
11	Service Area Street Lighting		(1,835,508)		8,129,855	0	8,129,855	8,129,855	$ -	0	-	-	8,129,855
12	City-Owned Private Outdoor Lighting		1,890,239		2,327,547	0	2,327,547	2,316,693	$ (10,854)	(10,854)	(1,177)	(12,031)	$ 2,315,516
13	Customer-Owned Non-Metered Lighting												$ 44,594
14	Customer-Owned Metered Lighting		269,156		178,964	0	178,964	178,130	$ (835)	(835)	(90)	(925)	$ 178,039
15	Total Base Revenue (before Billing Adjustment Factor)		$634,464,672	$637,437,247	$642,968,777	$0	$642,968,777	$640,008,318	($2,960,459)	$ (2,670,874)	$ (289,585)	($2,960,459)	$640,008,318
16													
17	Billing Adjustment Factor (Calculated to Actual)				($2,972,576)		-0.526%	-0.517%					
18													
19	Adjusted Totals (after Billing Adjustment Factor)				$639,996,201		$634,838,922	$631,878,463					

AUSTIN ENERGY
AUSTIN ENERGY SYSTEM PEAK DEMAND (MW)

Line	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2005	1,498	1,470	1,478	1,751	2,023	2,236	2,316	2,352	**2,445**	2,060	1,706	1,835
2	2006	1,370	1,553	1,338	2,054	2,048	2,297	2,372	2,416	2,266	2,009	1,607	1,585
3	2007	1,793	1,794	1,429	1,659	1,869	2,256	2,210	2,389	2,201	2,078	1,504	1,648
4	2008	1,647	1,653	1,547	1,964	2,342	2,412	2,486	2,514	2,441	2,034	1,648	1,873
5	2009	1,721	1,558	1,447	1,870	2,189	**2,538**	2,517	2,451	2,359	2,100	1,447	1,696
6	2010	1,948	1,734	1,553	1,680	2,102	2,267	2,302	2,628	2,275	1,867	1,701	1,628
7	2011	1,834	2,119	1,720	1,981	2,377	2,495	2,583	2,670	2,547	2,119	1,550	1,899
8	2012	1,711	1,634	1,771	2,025	2,346	**2,702**	2,526	2,530	2,515	2,018	1,671	1,650
9	2013	1,885	1,459	1,520	1,813	2,124	2,459	2,445	2,588	2,540	2,200	1,814	2,003
10	2014	2,105	2,033	2,066	1,946	2,042	2,272	2,420	2,567	2,462	2,207	1,852	1,764
11	2015	2,064	2,052	1,913	1,804	2,047	2,301	2,555	2,638	2,499	2,385	1,842	1,686
12	Count	11	11	11	11	11	11	11	11	11	11	11	11
13	Average	1,780	1,733	1,617	1,868	2,137	2,385	2,430	2,522	2,414	2,098	1,667	1,752
14	Std Dev	224	238	224	137	160	149	119	108	120	134	135	134

AUSTIN ENERGY
PERCENT OF ANNUAL SYSTEM PEAK DEMAND BY YEAR

Line	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2005	61.27%	60.12%	60.45%	71.62%	82.74%	91.45%	94.72%	96.20%	100.00%	84.25%	69.78%	75.05%
2	2006	56.71%	64.28%	55.38%	85.02%	84.77%	95.07%	98.18%	100.00%	93.79%	83.15%	66.51%	65.60%
3	2007	75.05%	75.09%	59.82%	69.44%	78.23%	94.43%	92.51%	100.00%	92.13%	86.98%	62.96%	68.98%
4	2008	65.51%	65.75%	61.54%	78.12%	93.16%	95.94%	98.89%	100.00%	97.10%	80.91%	65.55%	74.50%
5	2009	67.81%	61.39%	57.01%	73.68%	86.25%	100.00%	99.17%	96.57%	92.95%	82.74%	57.01%	66.82%
6	2010	74.12%	65.98%	59.09%	63.93%	79.98%	86.26%	87.60%	100.00%	86.57%	71.04%	64.73%	61.95%
7	2011	68.69%	79.36%	64.42%	74.19%	89.03%	93.45%	96.74%	100.00%	95.39%	79.36%	58.05%	71.12%
8	2012	63.32%	60.47%	65.54%	74.94%	86.82%	100.00%	93.49%	93.63%	93.08%	74.69%	61.84%	61.07%
9	2013	72.84%	56.38%	58.73%	70.05%	82.07%	95.02%	94.47%	100.00%	98.15%	85.01%	70.09%	77.40%
10	2014	82.00%	79.20%	80.48%	75.81%	79.55%	88.51%	94.27%	100.00%	95.91%	85.98%	72.15%	68.72%
11	2015	78.24%	77.79%	72.52%	68.39%	77.60%	87.23%	96.85%	100.00%	94.73%	90.41%	69.83%	63.91%
12	Average	69.60%	67.80%	63.18%	73.20%	83.65%	93.40%	95.17%	98.76%	94.53%	82.23%	65.32%	68.65%
13	6 Yr Avg	73.20%	69.86%	66.80%	71.22%	82.51%	91.74%	93.90%	98.94%	93.97%	81.08%	66.11%	67.36%

AUSTIN ENERGY

TEST OF HYPOTHESIS THAT MONTHLY PEAK DEMAND IS NOT SIGNIFICANTLY DIFFERENT FROM HISTORICAL AVERAGE SYSTEM PEAK MONTH

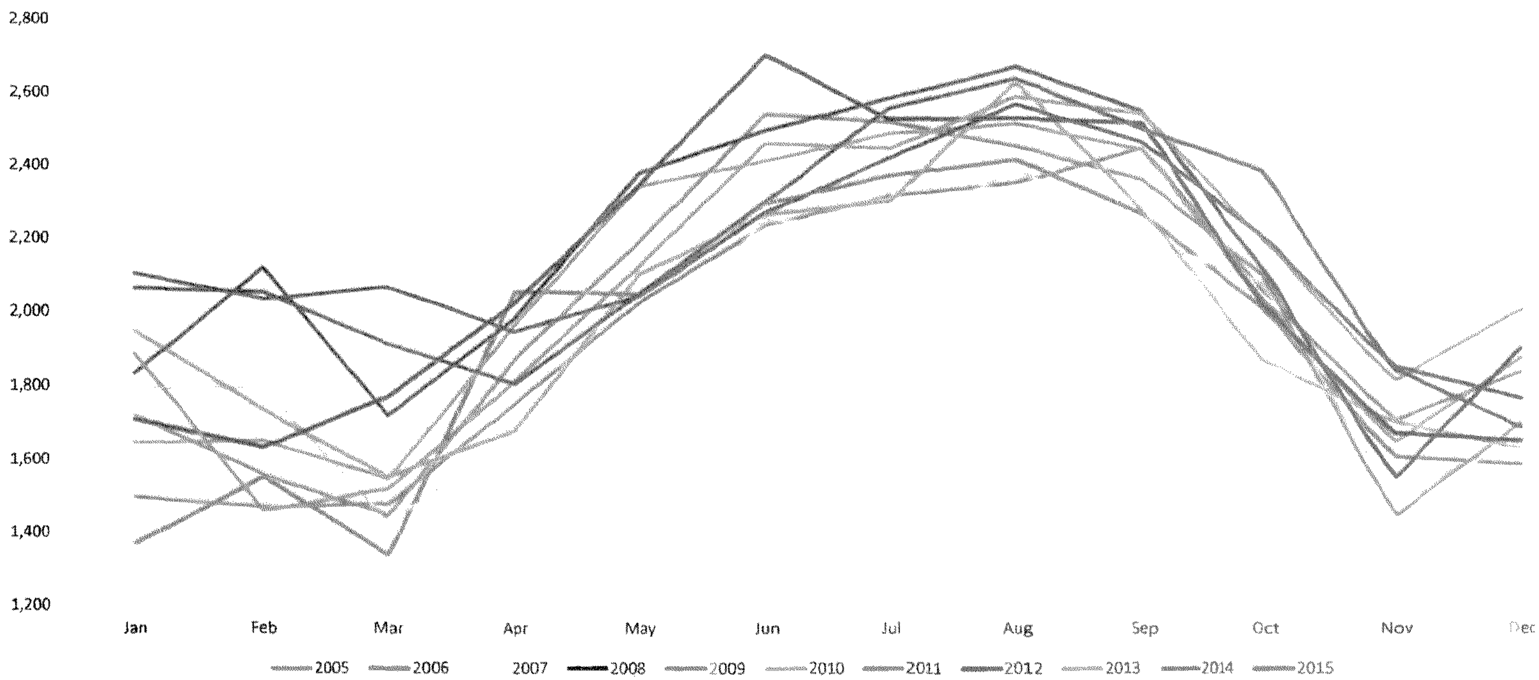
Line	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2005	Reject	Reject	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Reject	Reject	Reject
2	2006	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Reject	Reject	Reject	Reject
3	2007	Reject	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Reject	Reject	Reject	Reject
4	2008	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
5	2009	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
6	2010	Reject	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Reject	Reject	Reject	Reject
7	2011	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Accept	Reject	Reject	Reject
8	2012	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
9	2013	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
10	2014	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject
11	2015	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject
12	Accept	0	0	0	0	1	5	8	10	8	1	0	0
13	Reject	11	11	11	11	10	6	3	1	3	10	11	11
14	% Accepted	0%	0%	0%	0%	9%	45%	73%	91%	73%	9%	0%	0%

AUSTIN ENERGY

TEST OF HYPOTHESIS THAT MONTHLY SYSTEM PEAK DEMAND IS NOT SIGNIFICANTLY DIFFERENT FROM SAME YEAR ANNUAL SYSTEM PEAK MONTH DEMAND

Line	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2005	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject
2	2006	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
3	2007	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
4	2008	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Accept	Reject	Reject	Reject
5	2009	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
6	2010	Reject	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Reject	Reject	Reject	Reject
7	2011	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
8	2012	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
9	2013	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
10	2014	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject
11	2015	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject
12	Accept	0	0	0	0	1	7	10	11	10	0	0	0
13	Reject	11	11	11	11	10	4	1	0	1	11	11	11
14	% Accepted	0%	0%	0%	0%	9%	64%	91%	100%	91%	0%	0%	0%

AUSTIN ENERGY
GRAPHIC OF MONTHLY SYSTEM PEAK DEMANDS FOR THE PERIOD 2005-2015



AUSTIN ENERGY
AUSTIN ENERGY SYSTEM DEMAND AT TIME OF ERCOT PEAK (MW)

Line	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2006	1,370	1,553	1,338	2,054	2,048	2,297	2,372	2,416	2,266	2,009	1,607	1,585
2	2007	1,793	1,794	1,429	1,659	1,869	2,256	2,210	2,389	2,201	2,078	1,504	1,648
3	2008	1,647	1,653	1,547	1,964	2,342	2,412	2,486	2,514	2,441	2,034	1,648	1,873
4	2009	1,721	1,558	1,447	1,870	2,189	2,538	2,527	2,451	2,359	2,100	1,447	1,696
5	2010	1,948	1,734	1,553	1,680	2,102	2,267	2,302	2,628	2,275	1,867	1,701	1,628
6	2011	1,834	2,119	1,720	1,981	2,377	2,495	2,583	2,670	2,547	2,119	1,550	1,899
7	2012	1,711	1,634	1,771	2,025	2,346	2,702	2,526	2,530	2,515	2,018	1,671	1,650
8	2013	1,885	1,459	1,520	1,813	2,124	2,459	2,445	2,588	2,540	2,200	1,814	2,003
9	2014	2,105	2,033	2,066	1,946	2,042	2,272	2,420	2,567	2,462	2,207	1,852	1,764
10	2015	2,064	2,052	1,913	1,804	2,047	2,301	2,555	2,638	2,499	2,385	1,842	1,686
11	Count	10	10	10	10	10	10	10	10	10	10	10	10
12	Average	1,808	1,759	1,630	1,880	2,149	2,400	2,443	2,539	2,411	2,102	1,664	1,743
13	Std Dev	215	234	231	138	164	148	119	97	126	140	141	138

AUSTIN ENERGY
PERCENT OF ANNUAL SYSTEM PEAK DEMAND AT TIME OF ERCOT PEAK

Line	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2006	56.71%	64.28%	55.38%	85.02%	84.77%	95.07%	98.18%	100.00%	93.79%	83.15%	66.51%	65.60%
2	2007	75.05%	75.09%	59.82%	69.44%	78.23%	94.43%	92.51%	100.00%	92.13%	86.98%	62.96%	68.98%
3	2008	65.51%	65.75%	61.54%	78.12%	93.16%	95.94%	98.89%	100.00%	97.10%	80.91%	65.55%	74.50%
4	2009	67.81%	61.39%	57.01%	73.68%	86.25%	100.00%	99.57%	96.57%	92.95%	82.74%	57.01%	66.82%
5	2010	74.12%	65.98%	59.09%	63.93%	79.98%	86.26%	87.60%	100.00%	86.57%	71.04%	64.73%	61.95%
6	2011	68.69%	79.36%	64.42%	74.19%	89.03%	93.45%	96.74%	100.00%	95.39%	79.36%	58.05%	71.12%
7	2012	63.32%	60.47%	65.54%	74.94%	86.82%	100.00%	93.49%	93.63%	93.08%	74.69%	61.84%	61.07%
8	2013	72.84%	56.38%	58.73%	70.05%	82.07%	95.02%	94.47%	100.00%	98.15%	85.01%	70.09%	77.40%
9	2014	82.00%	79.20%	80.48%	75.81%	79.55%	88.51%	94.27%	100.00%	95.91%	85.98%	72.15%	68.72%
10	2015	78.24%	77.79%	72.52%	68.39%	77.60%	87.23%	96.85%	100.00%	94.73%	90.41%	69.83%	63.91%
11	Average	70.43%	68.57%	63.45%	73.36%	83.75%	93.59%	95.26%	99.02%	93.98%	82.03%	64.87%	68.01%
12	6 Yr Avg	73.20%	69.86%	66.80%	71.22%	82.51%	91.74%	93.90%	98.94%	93.97%	81.08%	66.11%	67.36%

AUSTIN ENERGY
TEST OF HYPOTHESIS THAT MONTHLY PEAK DEMAND IS NOT SIGNIFICANTLY DIFFERENT FROM HISTORICAL AVERAGE ERCOT SYSTEM PEAK MONTH

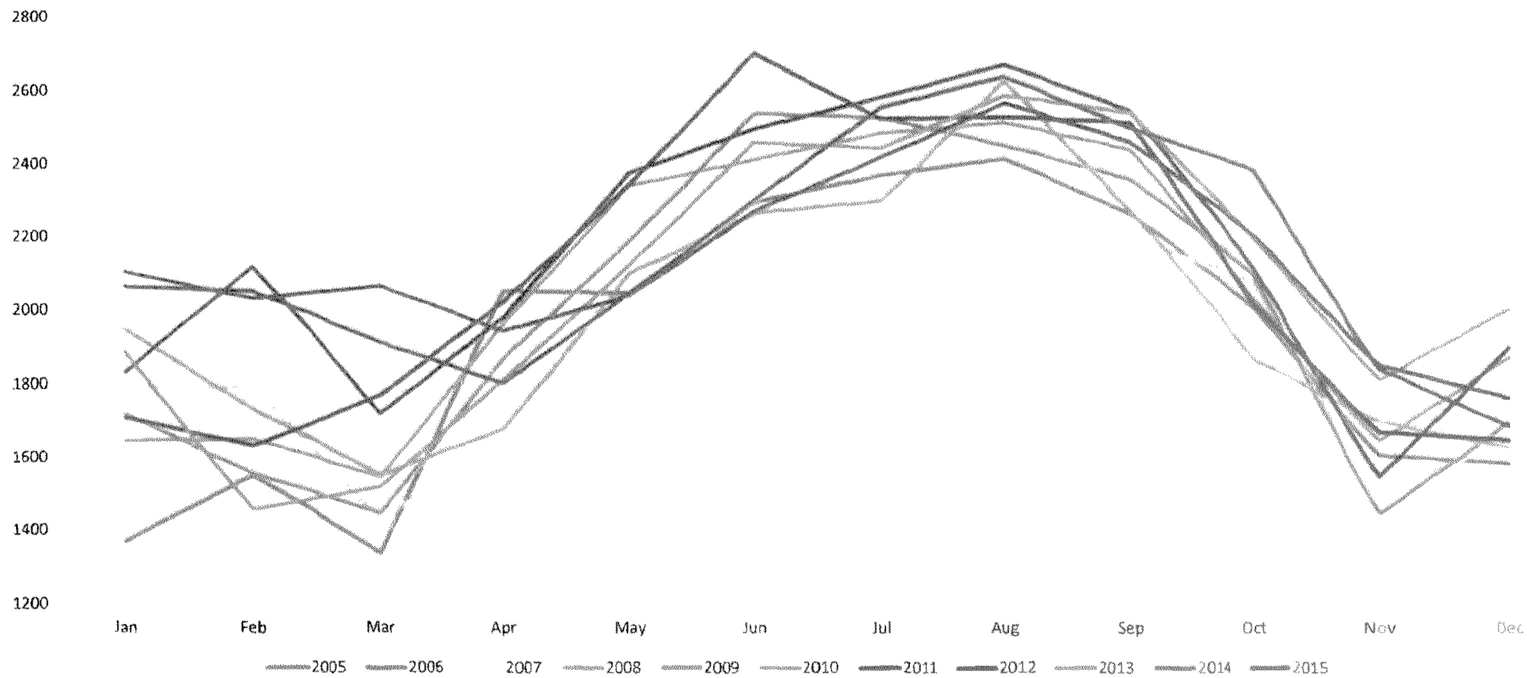
Line	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2006	Reject	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Reject	Reject	Reject	Reject
2	2007	Reject	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Reject	Reject	Reject	Reject
3	2008	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
4	2009	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject	Reject
5	2010	Reject	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Reject	Reject	Reject	Reject
6	2011	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
7	2012	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
8	2013	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
9	2014	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject
10	2015	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject
11	Accept	0	0	0	0	0	5	7	10	6	0	0	0
12	Reject	10	10	10	10	10	5	3	0	4	9	9	9
13	% Accepted	0%	0%	0%	0%	0%	50%	70%	100%	60%	0%	0%	0%

AUSTIN ENERGY

HYPOTHESIS THAT MONTHLY AUSTIN ENERGY SYSTEM PEAK DEMAND IS NOT SIGNIFICANTLY DIFFERENT FROM SAME YEAR ERCOT ANNUAL SYSTEM PEAK MONTH DE

Line	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2006	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
2	2007	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject	Reject
3	2008	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Accept	Reject	Reject	Reject
4	2009	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
5	2010	Reject	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Reject	Reject	Reject	Reject
6	2011	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
7	2012	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject	Reject
8	2013	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Accept	Reject	Reject	Reject
9	2014	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject
10	2015	Reject	Reject	Reject	Reject	Reject	Reject	Accept	Accept	Accept	Reject	Reject	Reject
11	Accept	0	0	0	0	1	7	9	10	7	0	0	0
12	Reject	10	10	10	10	9	3	1	0	3	10	10	10
13	% Accepted	0%	0%	0%	0%	10%	70%	90%	100%	70%	0%	0%	0%

AUSTIN ENERGY
GRAPHIC OF MONTHLY AUSTIN ENERGY DEMANDS AT TIME OF ERCOT SYSTEM PEAK FOR THE PERIOD 2005-2015



COMPARISON OF NXP/SAMSUNG AND AUSTIN ENERGY REVENUE REQUIREMENT RECOMMENDATIONS BY CLASS OF SERVICE

Line	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	Transmission Voltage	Transmission Voltage ≥ 20 MW @ 85% aLF	Service Area Street Lighting	City-Owned Private Outdoor Lighting	Customer-Owned Non-Metered Lighting	Customer-Owned Metered Lighting
1	Adjusted Present Revenues By Class and Type														
2	Base Revenue	$631,878,463	$257,192,459	$19,078,495	$155,552,648	$116,158,547	$19,259,649					$0	$2,315,516		$178,039
3	Recoverable Fuel	411,649,196	142,238,702	8,305,707	90,080,861	64,874,608	14,169,547					0	422,589		95,703
4	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
5	Community Benefit	44,731,030	19,383,746	1,184,830	8,857,050	8,086,739	1,551,697					0	138,778		14,508
6	Regulatory	123,670,241	53,145,269	2,302,720	26,683,594	22,726,498	4,567,294					0	6,774		15,087
7	Sub-total Pass Through Charges	$602,823,146	$216,739,108	$12,370,091	$127,707,963	$122,274,245	$26,988,277	$29,658,015	$55,962,813	$817,922	$9,547,335	$0	$568,141	$63,938	$125,298
8	Total Revenue	$1,234,701,609	$473,931,567	$31,448,586	$283,260,611	$238,432,792	$46,247,926	$52,291,023	$90,104,943	$2,152,614	$13,538,021	$0	$2,883,657	$108,532	$303,337
9															
10	NXP/Samsung Proposed Revenues by Class and Type														
11	Base Revenue	$499,332,467	$250,515,591	$14,328,932	$90,406,675	$78,012,569	$13,725,968					$7,257,421	$2,620,975		$179,114
12	Recoverable Fuel	342,844,601	118,051,338	6,893,341	74,762,818	70,441,876	11,760,048					1,195,405	350,729		79,429
13	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
14	Community Benefit	33,527,874	14,370,574	815,403	6,583,649	6,029,456	1,246,215					284,608	100,001		9,226
15	Regulatory	133,663,202	57,482,888	2,487,326	28,835,119	24,543,849	4,932,202					24,098	6,774		16,243
16	Sub-total Pass Through Charges	$532,808,356	$191,876,191	$10,772,905	$112,268,043	$107,601,580	$24,638,204	$26,049,237	$48,535,947	$682,686	$8,263,877	$1,504,111	$457,503	$53,174	$104,898
17	Total Revenue	$1,032,140,824	$442,391,782	$25,101,837	$202,674,718	$185,614,149	$38,364,171	$39,734,405	$72,887,241	$1,292,071	$11,850,076	$8,761,532	$3,078,478	$106,351	$284,013
18															
19	NXP/Samsung Proposed Revenue Increase / (Decrease) by Class and Type														
20	Base Revenue	($132,545,995)	($6,676,868)	($4,749,563)	($65,145,973)	($38,145,978)	($5,533,681)					$7,257,421	$305,459		$1,075
21	Recoverable Fuel	(68,804,595)	(24,187,365)	(1,412,366)	(15,318,043)	(14,432,732)	(2,409,499)					1,195,405	(71,860)		(16,274)
22	Green Choice	0	0	0	0	0	0					0	0		0
23	Community Benefit	(11,203,156)	(5,013,172)	(369,426)	(2,273,401)	(2,057,283)	(305,482)					284,608	(38,778)		(5,282)
24	Regulatory	9,992,960	4,337,620	184,606	2,151,524	1,817,350	364,908					24,098	(0)		1,156
25	Sub-total Pass Through Charges	($70,014,790)	($24,862,917)	($1,597,186)	($15,439,920)	($14,672,665)	($2,350,073)	($3,608,778)	($7,426,867)	($135,236)	($1,283,458)	$1,504,111	($110,638)	($10,764)	($20,400)
26	Total Proposed Revenue Change	($202,560,785)	($31,539,785)	($6,346,749)	($80,585,893)	($52,818,643)	($7,883,754)	($12,556,618)	($17,217,702)	($860,543)	($1,685,945)	$8,761,532	$194,821	($2,181)	($19,325)
27															
28	NXP/Samsung Proposed Revenue Increase / (Decrease) by Class and Type														
29	Base Revenue	-21.0%	-2.6%	-24.9%	-41.9%	-32.8%	-28.7%					NA	13.2%		0.6%
30	Recoverable Fuel	-16.7%	-17.0%	-17.0%	-17.0%	-17.0%	-17.0%					NA	-17.0%		-17.0%
31	Green Choice	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%					NA	NA		NA
32	Community Benefit	-25.0%	-25.9%	-31.2%	-25.7%	-25.4%	-19.7%					NA	-27.9%		-36.4%
33	Regulatory	8.1%	8.2%	8.0%	8.1%	8.0%	8.0%					NA	0.0%		7.7%
34	Sub-total Pass Through Charges	-11.6%	-11.5%	-12.9%	-12.1%	-12.0%	-8.7%	-12.2%	-13.3%	-16.5%	-13.4%	NA	-19.5%	-16.8%	-16.3%
35	Total Proposed Revenue Change	-16.4%	-6.7%	-20.2%	-28.4%	-22.2%	-17.0%	-24.0%	-19.1%	-40.0%	-12.5%	NA	6.8%	-2.0%	-6.4%

COMPARISON OF NXP/SAMSUNG AND AUSTIN ENERGY REVENUE REQUIREMENT RECOMMENDATIONS BY CLASS OF SERVICE

Line	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	Transmission Voltage	Transmission Voltage ≥ 20 MW @ 85% aLF	Service Area Street Lighting	City-Owned Private Outdoor Lighting	Customer-Owned Non-Metered Lighting	Customer-Owned Metered Lighting
1	AE Present Revenues by Class and Type														
2	Base Revenue	$631,878,463	$257,323,175	$19,088,191	$155,631,706	$116,217,584	$19,289,437					$0	$2,316,693		$178,130
3	Recoverable Fuel	411,649,196	142,238,702	8,305,707	90,080,861	84,874,608	14,169,547					0	422,589		95,703
4	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
5	Community Benefit	44,731,030	19,383,746	1,184,830	8,857,050	8,086,739	1,551,697					0	138,778		14,508
6	Regulatory	123,670,241	53,145,269	2,302,720	26,683,594	22,726,498	4,567,294					0	6,774		15,087
7	Sub-total Pass Through Charges	$602,823,146	$216,739,106	$12,370,091	$127,707,963	$122,274,245	$26,988,277	$29,658,015	$55,962,813	$817,922	$9,547,335	$0	$568,141	$63,938	$125,298
8	Total AE Proposed Cost of Service	$1,234,701,609	$474,052,283	$31,458,282	$283,339,669	$238,491,828	$46,257,714	$52,185,478	$89,945,727	$2,146,390	$13,517,421	$0	$2,884,834	$108,555	$303,428
9															
10															
11	NXP/Samsung Proposed Cost of Service by Class and Type														
12	Base Revenue	$499,332,467	$250,515,591	$14,328,932	$90,406,675	$76,012,569	$13,725,968					$7,257,421	$2,620,975		$179,114
13	Recoverable Fuel	342,844,601	118,051,338	6,893,341	74,762,818	70,441,876	11,760,048					1,195,405	350,729		79,429
14	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
15	Community Benefit	33,527,874	14,370,574	815,403	6,583,649	6,029,456	1,246,215					284,608	100,001		9,226
16	Regulatory	133,863,202	57,482,888	2,487,326	28,835,119	24,543,849	4,932,202					24,098	6,774		16,243
17	Sub-total Pass Through Charges	$532,808,356	$191,876,191	$10,772,905	$112,268,043	$107,601,580	$24,638,204	$26,049,237	$48,535,947	$682,686	$8,263,877	$1,504,111	$457,503	$53,174	$104,898
18	Total Proposed Cost of Service	$1,032,140,824	$442,391,782	$25,101,837	$202,674,718	$185,614,149	$38,364,171	$39,734,405	$72,887,241	$1,292,071	$11,850,078	$8,761,532	$3,078,478	$106,351	$284,013
19															
20															
21	NXP/Samsung Proposed Changes to Cost of Service by Class and Type														
22	Base Revenue	($132,545,995)	($6,807,584)	($4,759,259)	($65,225,031)	($38,205,015)	($5,543,470)					$7,257,421	$304,282		$985
23	Recoverable Fuel	(68,804,595)	(24,187,365)	(1,412,366)	(15,318,043)	(14,432,732)	(2,409,499)					1,195,405	-71,860		(16,274)
24	Green Choice	0	0	0	0	0	0					0	0		0
25	Community Benefit	(11,203,156)	(5,013,172)	(369,426)	(2,273,401)	(2,057,283)	(305,482)					284,608	-38,778		(5,282)
26	Regulatory	9,992,960	4,337,620	184,606	2,151,524	1,817,350	364,908					24,098	0		1,156
27	Sub-total Pass Through Charges	($70,014,790)	($24,862,917)	($1,597,186)	($15,439,920)	($14,672,665)	($2,350,073)	($3,608,778)	($7,426,867)	($135,236)	($1,283,458)	$1,504,111	($110,638)	($10,764)	($20,400)
28	Total Proposed Revenue Changes	($202,560,785)	($31,670,501)	($6,356,446)	($80,664,951)	($52,877,680)	($7,893,543)	($12,451,073)	($17,058,486)	($854,319)	($1,667,344)	$8,761,532	$193,644	($2,204)	($19,415)
29															
30	NXP Restated Present Revenues By Class and Type														
31	Base Revenue	$631,878,463	$257,192,459	$19,078,495	$155,552,648	$116,158,547	$19,259,649					$0	$2,315,516		$178,039
32	Recoverable Fuel	411,649,196	142,238,702	8,305,707	90,080,861	84,874,608	14,169,547					0	422,589		95,703
33	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
34	Community Benefit	44,731,030	19,383,746	1,184,830	8,857,050	8,086,739	1,551,697					0	138,778		14,508
35	Regulatory	123,670,241	53,145,269	2,302,720	26,683,594	22,726,498	4,567,294					0	6,774		15,087
36	Sub-total Pass Through Charges	$602,823,146	$216,739,106	$12,370,091	$127,707,963	$122,274,245	$26,988,277	$29,658,015	$55,962,813	$817,922	$9,547,335	$0	$568,141	$63,938	$125,298
37	Total Present Revenues	$1,234,701,609	$473,931,567	$31,448,586	$283,260,611	$238,432,792	$46,247,928	$52,291,023	$90,104,943	$2,152,614	$13,536,021	$0	$2,883,657	$108,532	$303,337
38															
39	NXP/Samsung Proposed Revenues														
40	Base Revenue	$499,332,467	$250,515,591	$14,328,932	$90,406,675	$76,012,569	$13,725,968					$7,257 421	$2,620,975		$179,114
41	Recoverable Fuel	342,844,601	118,051,338	6,893,341	74,762,818	70,441,876	11,760,048					1,195 405	350,729		79,429
42	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
43	Community Benefit	33,527,874	14,370,574	815,403	6,583,649	6,029,456	1,246,215					284,608	100,001		9,226
44	Regulatory	133,863,202	57,482,888	2,487,326	28,835,119	24,543,849	4,932,202					24,098	6,774		16,243
45	Sub-total Pass Through Charges	$532,808,356	$191,876,191	$10,772,905	$112,268,043	$107,601,580	$24,638,204	$26,049,237	$48,535,947	$682,686	$8,263,877	$1,504,111	$457,503	$53,174	$104,898
46	Total Proposed Revenues	$1,032,140,824	$442,391,782	$25,101,837	$202,674,718	$185,614,149	$38,364,171	$39,734,405	$72,887,241	$1,292,071	$11,850,078	$8,761,532	$3,078,478	$106,351	$284,013
47															
48	NXP/Samsung Proposed Revenue Increase / (Decrease) by Class and Type														
49	Base Revenue	($132,545,995)	($6,676,868)	($4,749,563)	($65,145,973)	($38,145,978)	($5,533,681)					$7,257,421	$305,459		$1,075
50	Recoverable Fuel	(68,804,595)	(24,187,365)	(1,412,366)	(15,318,043)	(14,432,732)	(2,409,499)					1,195,405	-71,860		(16,274)
51	Green Choice	0	0	0	0	0	0					0	0		0
52	Community Benefit	(11,203,156)	(5,013,172)	(369,426)	(2,273,401)	(2,057,283)	(305,482)					284,608	-38,778		(5,282)
53	Regulatory	9,992,960	4,337,620	184,606	2,151,524	1,817,350	364,908					24,098	0		1,156
54	Sub-total Pass Through Charges	($70,014,790)	($24,862,917)	($1,597,186)	($15,439,920)	($14,672,665)	($2,350,073)	($3,608,778)	($7,426,867)	($135,236)	($1,283,458)	$1,504,111	($110,638)	($10,764)	($20,400)
55	Total Proposed Revenue Change	($202,560,785)	($31,539,785)	($6,346,749)	($80,585,893)	($52,818,643)	($7,883,754)	($12,556,618)	($17,217,702)	($860,543)	($1,685,945)	$8,761,532	$194,821	($2,181)	($19,325)
56															
57	NXP/Samsung Proposed Revenue Increase / (Decrease) by Class and Type														
58	Base Revenue	-21.0%	-2.6%	-24.9%	-41.9%	-32.8%	-28.7%					NA	13.2%		0.6%
59	Recoverable Fuel	-16.7%	-17.0%	-17.0%	-17.0%	-17.0%	-17.0%					NA	-17.0%		-17.0%
60	Green Choice	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%					NA	NA		NA
61	Community Benefit	-25.0%	-25.9%	-31.2%	-25.7%	-25.4%	-19.7%					NA	-27.9%		-36.4%
62	Regulatory	8.1%	8.2%	8.0%	8.1%	8.0%	8.0%					NA	0.0%		7.7%
63	Sub-total Pass Through Charges	-11.6%	-11.5%	-12.9%	-12.1%	-12.0%	-8.7%	-12.2%	-13.3%	-16.5%	-13.4%	NA	-19.5%	-16.8%	-16.3%
64	Total Proposed Revenue Change	-16.4%	-6.7%	-20.2%	-28.4%	-22.2%	-17.0%	-24.0%	-19.1%	-40.0%	-12.5%	NA	6.8%	-2.0%	-6.4%

COMPARISON OF NXP/SAMSUNG AND AUSTIN ENERGY REVENUE REQUIREMENT RECOMMENDATIONS BY CLASS OF SERVICE

Line	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	Transmission Voltage	Transmission Voltage ≥ 20 MW @ 85% aLF	Service Area Street Lighting	City-Owned Private Outdoor Lighting	Customer-Owned Non-Metered Lighting	Customer-Owned Metered Lighting
1	AE Filing Present Revenue														
2	Base Revenue	$631,878,463	$257,323,175	$19,068,191	$155,631,706	$116,217,584	$19,289,437					$0	$2,316,693		$178,130
3	Recoverable Fuel	411,649,196	142,238,702	8,305,707	90,060,861	84,674,608	14,169,547					0	422,589		95,703
4	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
5	Community Benefit	44,731,030	19,383,746	1,184,830	8,857,050	8,096,739	1,551,697					0	138,778		14,908
6	Regulatory	123,670,241	53,145,269	2,302,720	26,683,594	22,726,498	4,567,294					0	6,774		15,087
7	Sub-total Pass Through Charges	$602,823,146	$216,739,108	$12,370,091	$127,707,963	$122,274,245	$26,968,277	$29,658,618	$55,962,813	$817,922	$9,547,335	$0	$568,141	$53,938	$125,298
8	Total Revenue	$1,234,701,609	$474,062,283	$31,458,282	$283,339,669	$238,491,828	$46,257,714	$52,186,478	$89,945,727	$2,146,390	$13,517,421	$0	$2,884,834	$108,565	$303,428
9															
10	NXP/Samsung Proposed Cost of Service Before Allocation and SASL Adjustments														
11	Base Revenue	$491,455,166	$239,670,955	$15,556,192	$92,861,670	$81,815,867	$12,853,238					$0	$2,517,736		$210,067
12	Recoverable Fuel	341,649,196	118,051,338	6,893,341	74,762,818	70,441,876	11,760,048					0	350,729		79,429
13	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
14	Community Benefit	42,624,679	17,758,215	1,083,244	8,603,823	7,958,392	1,555,092					0	118,563		12,955
15	Regulatory	133,639,104	57,482,886	2,487,326	28,835,119	24,543,849	4,932,202					0	6,774		16,243
16	Sub-total Pass Through Charges	$540,685,657	$195,261,831	$11,040,746	$114,288,217	$109,530,516	$24,947,081	$26,508,956	$49,382,156	$690,183	$8,397,464	$0	$476,066	$53,774	$108,627
17	Total Proposed Revenue	$1,032,140,824	$434,932,786	$26,596,938	$207,149,887	$191,346,383	$37,800,319	$41,783,956	$75,643,659	$1,150,308	$12,129,040	$0	$2,993,801	$94,850	$318,695
18															
19	NXP/Samsung Proposed Revenue Requirement Changes Before SASL Adjustments														
20	Base Revenue	($140,423,297)	($17,652,220)	($3,531,999)	($62,770,036)	($34,401,717)	($6,416,200)					$0	$201,043		$31,938
21	Recoverable Fuel	(70,000,000)	(24,187,365)	(1,412,366)	(15,318,043)	(14,432,732)	(2,409,499)					0	-71,860		(16,274)
22	Green Choice	0	0	0	0	0	0					0	0		0
23	Community Benefit	(2,106,351)	(1,627,531)	(101,585)	(253,227)	(138,347)	3,395					0	-20,216		(1,553)
24	Regulatory	9,968,862	4,337,620	184,606	2,151,524	1,817,350	364,908					0	0		1,156
25	Sub-total Pass Through Charges	($62,137,489)	($21,477,275)	($1,329,345)	($13,419,746)	($12,743,729)	($2,041,196)	($3,149,019)	($6,580,657)	($127,739)	($1,149,871)	$0	($92,076)	($10,164)	($16,671)
26	Total Proposed Revenue Changes	($202,560,785)	($39,129,496)	($4,861,344)	($76,189,782)	($47,145,445)	($8,457,395)	($10,401,520)	($14,101,868)	($996,081)	($1,388,381)	$0	$109,967	($13,715)	$15,267
27															
28	NXP/Samsung Proposed Cost of Service Before Allocation Adjustments with Service Area Street Lighting included														
29	Base Revenue	$499,332,467	$241,475,745	$14,638,173	$95,208,424	$91,894,392	$12,948,845					$6,268,554	$2,140,509		$185,501
30	Recoverable Fuel	342,844,601	118,051,338	6,893,341	74,762,818	70,441,876	11,760,048					1,195,405	350,729		79,429
31	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
32	Community Benefit	33,527,874	14,012,693	856,981	6,669,438	6,160,288	1,217,487					289,324	96,567		10,269
33	Regulatory	133,663,202	55,863,411	3,416,467	26,588,577	24,558,782	4,853,667					1,153,427	384,978		40,940
34	Sub-total Pass Through Charges	$532,808,356	$189,898,833	$11,743,624	$110,107,291	$107,747,345	$24,530,941	$26,904,490	$49,123,507	$812,908	$8,184,289	$2,638,157	$832,275	$53,988	$130,638
35	Total Proposed Revenue Requirement	$1,032,140,824	$431,374,578	$26,381,797	$205,315,715	$199,641,737	$37,479,786	$41,399,731	$75,111,798	$1,138,518	$12,007,639	$8,906,710	$2,972,784	$93,907	$316,140
36															
37	NXP/Samsung Proposed Cost of Service Changes Before Allocation Adjustments with Service Area Street Lighting Included in Allocations														
38	Base Revenue	$7,877,301	$1,804,790	($918,019)	$2,346,754	$78,525	$95,607					$6,268,554	-$377,227		($24,566)
39	Recoverable Fuel	1,195,405	0	0	0	0	0					1,195,405	0		0
40	Green Choice	0	0	0	0	0	0					0	0		0
41	Community Benefit	(9,096,805)	(3,743,522)	(226,263)	(1,934,384)	(1,798,104)	(337,605)					289,324	-21,995		(2,685)
42	Regulatory	24,098	(1,619,477)	929,141	(2,246,542)	14,934	(78,534)					1,153,427	378,205		24,697
43	Sub-total Pass Through Charges	($7,877,301)	($5,362,998)	$702,879	($4,180,926)	($1,783,171)	($416,140)	$485,494	($258,649)	$122,815	($213,195)	$2,638,157	$356,209	$10,214	$22,012
44	Total Cost of Service Change	$0	($3,558,208)	($215,140)	($1,834,172)	($1,704,646)	($320,533)	($384,227)	($732,071)	($11,791)	($121,401)	$8,906,710	($21,018)	($948)	($2,554)
45															
46	NXP/Samsung Proposed Cost of Service After Production Demand-Related Allocation Factor Change with SASL Included														
47	Base Revenue	$499,332,467	$247,738,157	$14,584,029	$90,861,449	$78,714,507	$13,468,992					$7,782,421	$2,611,095		$218,661
48	Recoverable Fuel	342,844,601	118,051,338	6,893,341	74,762,818	70,441,876	11,760,048					1,195,405	350,729		79,429
49	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
50	Community Benefit	33,527,874	14,277,323	823,968	6,598,917	6,053,023	1,237,587					302,235	99,689		10,354
51	Regulatory	133,663,202	57,482,886	2,487,326	28,835,119	24,543,849	4,932,202					24,098	6,774		16,243
52	Sub-total Pass Through Charges	$532,808,356	$191,782,940	$10,781,470	$112,283,312	$107,625,147	$24,629,576	$26,061,752	$48,558,998	$682,705	$8,264,128	$1,521,738	$457,172	$53,193	$106,228
53	Total Revenue Requirement	$1,032,140,824	$439,521,097	$25,365,499	$203,144,761	$186,339,654	$38,098,568	$40,119,970	$73,596,863	$1,292,660	$11,857,809	$9,304,159	$3,068,267	$106,930	$324,887
54															
55	NXP/Samsung Proposed Cost of Service Changes Due to Production Demand-Related Allocation Factor Change														
56	Base Revenue	$0	$6,262,412	($54,144)	($4,346,975)	($3,179,885)	$520,147					$1,513,868	$470,586		$33,160
57	Recoverable Fuel	0	0	0	0	0	0					0	0		0
58	Green Choice	0	0	0	0	0	0					0	0		0
59	Community Benefit	0	264,630	(33,013)	(70,521)	(107,264)	20,100					12,911	3,102		284
60	Regulatory	(0)	1,619,477	(929,141)	2,246,542	(14,934)	78,534					-1,129,329	-378,205		(24,697)
61	Sub-total Pass Through Charges	($0)	$1,884,107	($962,155)	$2,176,021	($122,198)	$98,635	($932,738)	($564,509)	($130,293)	$79,659	($1,116,419)	($375,103)	($10,795)	($24,413)
62	Total Revenue Requirement Changes	($0)	$8,146,519	($1,016,299)	($2,170,954)	($3,302,083)	$618,782	($1,280,060)	($1,514,924)	$154,142	($149,831)	$397,449	$95,483	$13,030	$8,747
63															
64	NXP/Samsung Proposed Cost of Service After Production Demand-Related and Distribution Substation, Poles & Conductor Allocation Factor Changes														
65	Base Revenue	$499,332,467	$250,515,591	$14,328,932	$90,406,675	$78,012,569	$13,725,968					$7,257,421	$2,620,975		$179,114
66	Recoverable Fuel	342,844,601	118,051,338	6,893,341	74,762,818	70,441,876	11,760,048					1,195,405	350,729		79,429
67	Green Choice	22,772,679	1,971,391	576,835	2,086,458	6,586,400	6,699,739					0	0		0
68	Community Benefit	33,527,874	14,370,574	815,403	6,583,649	6,029,456	1,246,215					284,608	100,001		9,226
69	Regulatory	133,663,202	57,482,886	2,487,326	28,835,119	24,543,849	4,932,202					24,098	6,774		16,243
70	Sub-total Pass Through Charges	$532,808,356	$191,876,191	$10,772,905	$112,268,043	$107,801,580	$24,638,204	$26,049,237	$48,535,947	$682,686	$8,263,877	$1,504,131	$457,503	$53,174	$104,895
71	Total Proposed Revenue	$1,032,140,824	$442,391,782	$25,101,837	$202,674,718	$185,614,149	$38,364,171	$39,734,405	$72,887,241	$1,292,071	$11,850,078	$8,761,532	$3,078,478	$106,351	$284,013
72															
73	NXP/Samsung Proposed Cost of Service Changes Due to Distribution Substation, Poles & Conductor Allocation Factor Changes														
74	Base Revenue	($0)	$2,777,434	($255,097)	($454,774)	($701,938)	$255,976					-$525,001	$9,880		($38,547)
75	Recoverable Fuel	0	0	0	0	0	0					0	0		0
76	Green Choice	0	0	0	0	0	0					0	0		0
77	Community Benefit	(0)	93,251	(8,565)	(15,269)	(23,567)	8,628					-17,627	332		(1,329)
78	Regulatory	0	0	0	0	0	0					0	0		0
79	Sub-total Pass Through Charges	($0)	$93,251	($8,565)	($15,269)	($23,567)	$8,628	($12,515)	($23,051)	($19)	($251)	($17,627)	$332	($19)	($1,329)
80	Total Proposed Revenue Changes	($0)	$2,870,684	($263,662)	($470,043)	($725,505)	$265,604	($385,385)	($708,623)	($589)	($7,732)	($542,627)	$10,212	($579)	($40,875)
81															
82	NXP/Samsung Proposed Cost of Service Impacts Resulting from All Allocation Factor Changes														
83	Base Revenue	($0)	$9,039,846	($309,241)	($4,801,749)	($3,881,823)	$777,123					$988,867	$480,466		($5,387)
84	Recoverable Fuel	0	0	0	0	0	0					0	0		0
85	Green Choice	0	0	0	0	0	0					0	0		0
86	Community Benefit	(0)	357,881	(41,578)	(85,790)	(130,831)	28,729					-4,716	3,433		(1,044)
87	Regulatory	0	1,619,477	(929,141)	2,246,542	(14,934)	78,534					-1,129,329	-378,205		(24,697)
88	Sub-total Pass Through Charges	$0	$1,977,358	($970,719)	$2,160,752	($145,765)	$107,263	($945,253)	($587,561)	($130,312)	$79,608	($1,134,045)	($374,771)	($10,810)	($25,741)
89	Total Proposed Revenue Changes	$0	$11,017,203	($1,279,961)	($2,640,998)	($4,027,588)	$884,385	($1,665,325)	($2,224,547)	$153,553	($157,663)	($145,178)	$105,695	$12,451	($32,126)

COMPARISON OF AUSTIN ENERGY POWER SUPPLY COSTS VS. ERCOT MARKET SUPPLY COSTS

		Total Austin Energy Production Cost		Production Cost of Service for Primary ≥ 20 MW	
Line	Description	Austin Energy Recommendation	NXP/Samsung Recommendation	Austin Energy Recommendation	NXP/Samsung Recommendation
1	Production				
2	Demand Related				
3	Nuclear	$122,595,402	$118,487,140	$8,817,075	$7,875,766
4	Coal	69,098,235	51,095,095	4,969,553	3,396,259
5	Natural Gas	68,337,713	61,571,910	4,914,856	4,092,647
6	Quick Response - Natural Gas	43,737,097	42,213,377	3,145,577	2,805,897
7	Renewable - Wind	10,180	10,316	732	686
8	Renewable - Solar	4,269,035	4,311,954	307,029	286,613
9	Renewable - Landfill Methane	0	0	0	0
10		$308,047,663	$277,689,793	$22,154,823	$18,457,868
11					
12	Energy Related				
13	NXP/Samsung Adjustment to Fuel Expense	$0	($70,000,000)	$0	($7,235,636)
14	Nuclear	27,134,781	27,134,829	2,804,820	2,804,825
15	Coal	91,895,824	91,895,988	9,498,925	9,498,942
16	Natural Gas	47,697,842	47,697,927	4,930,346	4,930,355
17	Quick Response - Natural Gas	10,607,468	10,607,487	1,096,454	1,096,456
18	Economy - Purchased Power	3,646,336	3,646,220	376,908	376,896
19	Renewable - Wind	229,453,055	229,445,733	23,717,698	23,716,941
20	Renewable - Solar	2,385,512	2,385,435	246,581	246,573
21	Renewable - Landfill Methane	23,784	23,784	2,459	2,458
22	Energy Related Less $70 million Adjustment	$412,844,601	$342,837,402	$42,674,191	$35,437,811
23					
24	Other				
25	ERCOT Administration Fees	6,838,000	$6,837,999	698,445	$698,445
26	Energy Efficiency Programs	$33,527,875	33,527,874	$2,381,718	2,388,061
27	GreenChoice	22,772,679	22,779,832	1,539,000	1,539,483
28		$63,138,554	$63,145,705	$4,619,163	$4,625,990
29					
30	Total Production	$784,030,818	$683,672,900	$69,448,177	$58,521,668
31					
32	Total kWh Sold	12,560,548,927	12,560,548,927	1,305,420,231	1,305,420,231
33					
34	AE Power Supply Cost per kWh	$0.0624	$0.0544	$0.0532	$0.0448
35	ERCOT Power Supply Cost per kWh [1]	$0.0322	$0.0322	$0.0322	$0.0322
36	Excess of Austin Energy Cost Above ERCOT Cost	$0.0303	$0.0223	$0.0210	$0.0127
37	Extended Cost of AE Power Above ERCOT Supply	$380,041,696	$279,683,778	$27,461,511	$16,535,002
38					
39	Note: [1] Calculated using ERCOT 2015 load weighted hourly settled prices provided in AE's response to Public Citizen / Sierra Club RFI No. 1-4.				