AUSTIN ENERGY
2016 JUL 22 AM 11:20

AUSTIN ENERGY'S TARIFF PACKAGE:	§	
2015 COST OF SERVICE STUDY AND PROPOSAL TO CHANGE	§ §	**BEFORE THE CITY OF AUSTIN IMPARTIAL HEARING EXAMINER**
BASE ELECTRIC RATES	§	

AUSTIN ENERGY LOW INCOME CONSUMERS' MOTION TO RECONSIDER

TO THE HONORABLE JUDGE HERRERA:

COMES NOW, Austin Energy Low Income Consumers ("AELIC") requesting Your Honor to reconsider certain portions of your report stating as follows:

I.

Introduction

AELIC has drafted its points as exceptions. However, our request for relief is a request for Your Honor to reconsider these points and upon reconsideration, adopt the relief requested by AELIC.

The Independent Hearing Examiner's ("IHE") Report reflected an attention to the parties' arguments. AELIC acknowledges and appreciates the work Your Honor put in at the hearing and in your report. Many of the points AELIC supported were addressed consistent with our request for relief. Other points AELIC supported were addressed in part consistent with our request for relief and some of the points set out below reflect this fact. Still other points AELIC supported were addressed inconsistent with our request. AELIC will be addressing these points. AELIC will not be addressing many of the points. Our silence on these points, particularly, the points related to the cost of service should not be considered agreement or disagreement with the decision.

Because of scheduling conflicts and a misunderstanding when these exceptions were due, AELIC will be shortening many of its arguments into bullet points. We are asking that Your Honor consider these bullet points with the same attention you would provide for a more traditional argument.

II.

Exceptions

1. <u>While the IHE correctly found that an adjustment to AE's proposed level of non nuclear decommissioning reserve should be made, he neglected to consider the rate effect of AE's deferment of the Decker Plant Retirement and the corresponding ERCOT time lag to when actual decommissioning activities commence which would at the very least change AE's proposed $28 million recovery over two years to three years, an additional reduction of $4,666,667 to AE's revenue requirement included in its cost of service. Moreover, the IHE neglected to consider the ERCOT lag time between the announcement of plant retirement and actual decommissioning which is 30 to 36 months. Using the conservative 30 month increase over the three years until the Decker Plant's estimated retirement, the years AE has to recover the $28 million before decommissioning begins on the Decker Plant increase to 5.5. Recognizing this additional 2.5 year recovery period reduces AE's revenue requirement an additional $4,242,424.</u>

AE included costs to fund a non nuclear decommissioning reserve in its revenue requirement. According to AE, "{t}he objective of the Non-Nuclear Decommissioning Reserve is to accumulate sufficient funds over the remaining life of each power plant to pay for decommissioning activities after the plant is taken out of service."[1]

AE set the annual level of cost recovery relating to the decommissioning of Decker (two of the operating units) at $14 million representing ½ the highest estimated Decker decommissioning costs of $28 million.[2] Recovering ½ of the total decommissioning estimate in one year assumes a two year recovery period was necessary for AE to have the funds available to fund "decommissioning activities after the plant is taken out of service"[3] But this recovery period was

[1] AE Exhibit No. 1, Bates Stamp p. 487.

[2] Actually AE rounded up this estimated cost. The highest Decker plant decommissioning cost is estimated by its experts to be $27,721,374, $278,626 less than the amount AE relied upon in its testimony. See AE Ex. No. 1, Bates Stamp p. 521; AE Ex. No. 1, Bates Stamp p. 093. AELIC will use the actual number of $27,721,374 set out in AE's decommissioning study and requests the IHE to do so as well.

[3] See footnote No. 1.

amended at the hearing. AE witness Ball testified that the plan to retire Decker (the two units) has been delayed a year.[4] This means AE has three, not two years to recover its decommissioning costs before Decker (two units) is retired. Consequently, the estimated decommissioning costs for Decker at the very least should be recovered over three years, not two at an annual expense of $9,240,458 (27,721,374[5] ÷3), resulting in a reduction in AE's annual recovery cost of $4,759,542 in its revenue requirement.

The reduction set out above is a conservative one. At the hearing AE witness Ball testified that decommissioning activities will not commence until 30-36 months after the Council determines the Decker plant operating units should be retired.[6] This is because upon determining that the Decker plant operating units will be retired, AE would "enter their (ERCOT) regional planning process"[7] which "would probably be a 30-36 month process from the time we notice them (ERCOT) to having a plan for transition."[8] Because of the regional planning, AE will have an additional 2.5 to 3 years before it commences decommissioning activities. Consequently, AE will have 5.5 to 6 years to collect revenues from its ratepayers for the decommissioning activities. Dividing the total highest AE-estimated decommissioning costs for Decker by 5.5 results in an annual cost recovery of $5,040,249 ($27,721,374 ÷5.5), a total decrease (including the first reduction stated above) of $8,959,751.

2. <u>The IHE erred in neglecting to make the adjustment proposed by ICA witness Johnson involving AE's proposed costs of decommissioning the Decker Plant AE included for purposes of setting rates because: AE's proposed cost is based on the highest estimate for the costs established in a study, totally disregarding the low estimate provided in the decommissioning cost study; and also because the study relied upon by AE was classified by the utility as confidential and neither the IHE nor the parties were able to review the study's costs for reasonableness and necessity even though decommissioning cost studies are not confidential in</u>

[4] Tr. pp. 184-185. (". . .we announced our intent to postpone the project associated with construction of a replacement asset for two of the Decker units and that is in tandem with the retirement decision. . . .we're going to postpone funding that project for a year.")
[5] AELIC is using the actual highest cost estimated by AE's decommissioning study.
[6] Tr. pp. 186-187.
[7] Tr. p. 186
[8] Tr. p. 187

PUC hearings and AE's expert witness Mancinnelli was surprised that the cost study he sponsored was considered confidential . (The only thing provided was the aggregate range of total costs.) Tr. 766-769

AELIC has succinctly stated its argument under this error in its post hearing brief and incorporates those arguments herein. AELIC additionally asks the IHE to consider that AE's reliance on benchmark costs from regulatory rate cases was more transparent than AE's "detailed study" mentioned but not revealed in this rate proceeding. As AELIC witness Szerszen pointed out, utilities do not file their decommissioning studies under a confidential classification in Texas PUC rate proceedings.[9] Parties in these Texas PUC proceedings have the right to review the actual detailed cost studies and to make adjustments to the cost elements. This is not the case for the AE "detailed study". None of the "details" were available to the parties. Not even the cost elements at an aggregated level were made available to the parties.[10]

The "detailed study" estimated decommissioning costs ranged from a low of $18,551,374 to a high of $27,721,374[11], a difference of $9,170,000. AE did not provide any proof that the $27.7 million was reasonable and necessary. Nor did AE present any evidence that the low range estimate was unreasonable. The "detailed study" simply set out the range of alleged reasonable values. In the absence of any proof that the low range estimate is unreasonable, AE failed in its burden of proving the reasonableness of its requested use of the high range estimate.

The regulatory decisions AE relied upon as proxies to estimate decommissioning costs for FPP and Sand Hill power plants show that regulatory authorities again and again reject a utility's high range estimate of decommissioning costs and find some lesser amount reasonable for purposes of inclusion in rates. Consequently, in the absence of any credible evidence, Your Honor should not continue to adopt AE's high range of estimated decommissioning costs—especially since AE provided no credible evidence to

[9] AELIC Ex. No. 3, pp. 7&8

[10] See AE Ex. No. 1, Bates Stamp p. 521 which lists the "tasks" but redacts the aggregated costs for each task. Even the contingency percentage was left off the study.

[11] *Id.*

show why its low estimate for its decommissioning costs that included a contingency[12] was unreasonable. While AELIC still contends AE should not be allowed any recovery for failure to provide credible evidence as to the reasonableness of its requested amounts,[13] we request Your Honor to adopt ICA witness Johnson's adjustment because his recommendation is based on a reasonable analysis.

3. <u>While acknowledging that AE's level of bad debt included in its rate case was too high, the IHE's adjustment is insufficient in light of the more credible evidence in the record that shows the adjustment should have been a reduction of bad debt cost to the FY 2015 level.</u>

As in Exception No. 2, AELIC extensively briefed this issue in its post hearing brief and incorporates those arguments into these Exceptions. AELIC wants to add a few additional points in this Exception that further support AELIC's recommended adjustment to AE's bad debt expense as reasonable and should be adopted.

First, AELIC and Samsung's recommendation to use the FY actual bad debt expense level is within the range of values ICA witness Johnson found. In fact, using the full seven years of data, 2008 to 2015, the average bad debt expense is $8.2 million, slightly less than the FY 2015 actual bad debt amount. This factor shows that the actual FY 2015 bad debt expense is reasonable considering the full seven years of available data.

Second, AELIC Ex. 38 shows that AE expected increases in its bad debt expenses when it implemented its new billing program and that the level would go down. Ex. 38 represents a portion of AE's presentation to the City Council in June 2014 regarding bad debt. At p. 12 of that presentation, entitled "Historical Trends", AE showed the effect in its new billing system in 1999 substantially increased its active debt. Page 12 reveals that in 2000 and 2001 AE's active accounts receivables[14] were significantly higher than subsequent years. And since the data was not adjusted for number of customers, the high level of active

[12] A contingency is a fudge factor. It is a percentage of the cost and increases an estimated cost by that percentage. For instance, a contingency of 10% increases an estimated cost to 110% of the costs estimated, in this case, needed to decommission a plant.

[13] Conclusory statements are not credible evidence especially when the utility itself establishes a range of estimated decommissioning costs.

[14] Mr. Overton explained that A/R in AE's presentation meant accounts receivable and that CIS refers to the billing system that was put into place in 1999. See Tr. pp. 898 & 899.

account receivables in 2000 and 2001 with less customers in relation to 2011 with increased customers reinforce the fact that the bad debt levels for FY 2013 and FY 2014 are outliers in the range of bad debt levels Mr. Johnson reviewed.[15] Consequently, the seven year average will produce a more reasonable level than the five year average. The five year average is heavily influenced by the FY 2013 and FY 2014 levels and results in an unreasonable amount. AELIC will be attaching AELIC Ex. 38 to these Exceptions.

Third, two events will influence the level of bad debt going forward. As AELIC mentioned in its post hearing brief, Samsung witness Fox testified that bad debt level is influenced by rates, and the fact that the PSA rate has decreased should lead to lower levels of debt. In addition, AE stated to the council that one of the causes of a rise to bad debt levels is "Higher summer bills"[16]. The IHE's decision to recommend the elimination of the seasonal rate will reduce summer bills.[17] Since AE has identified "higher summer bills" as a cause of bad debt, the elimination of the seasonal rate should cause a decrease in bad debt levels.

In conclusion, AE and Samsung's recommended use of the actual FY 2015 bad debt level is consistent with ICA witness Johnson's analysis, reflects the end of the bad debt bubble caused by the implementation of a new billing system, and recognizes the dampening effect of lower PSA rates and the elimination of the seasonal rate will have on AE's bad debt levels. AELIC requests Your Honor to consider these additional factors and upon reconsideration find and recommend that the level of bad debt should be set at the FY 2015 level.

4. <u>Even though the IHE recognized that AE's proposed new financial policies would reduce AE's positive net reserve level costs AE requested to be included in rates, he failed to find and recommend that regardless of whether new financial policies are established AE has conceded that its net reserve level of $34 million should be reduced to $11 million before any other adjustments should be made because the lower level of reserves were testified to by AE as adequate and reasonable.</u>

[15] See ICA Ex. No. 1 at p. 13 that shows the levels of debt for each year from 2008 to 2015.
[16] AELIC Ex. No. 38.
[17] According to AE, "{s}easonal base rates have increased AE's financial risk because a large portion of its revenue requirement is designed to be recovered in the four summer months." See AE Ex. No. 1, p. 136.

5. While the IHE correctly determined that $14.5 million in revenues realized from AE's sale of its property related to its retired control center should be included in AE's rate case, he neglected to definitely recommend this revenue be considered an offset to any costs related to its financial reserves and its non nuclear decommissioning reserve.

6. The IHE neglected to adjust AE's reserves to account for the $29 million in revenues AE will realize from its regulatory charge rates that caused AE to increase its regulatory charge $5 a month for typical residential bills to in part replenish AE's reserves. See attached AELIC Ex. No. 19

These three exceptions relate to AE's reserves and will be discussed here. AELIC will not be discussing the additional adjustments to AE's reserve levels caused by reductions in AE's revenue requirements. These adjustments should be made after the adjustments discussed below.

In AE's revenue requirement AE stated that its reserve levels were short by $34 million and it sought to recover this amount over three years. However, AE proposed an alternative reserve level calculation with a finding that it was short $11 million a reduction of $20 million from its test year revenue requirement levels. The $11 million was testified to by AE as adequate for AE business operations. In fact, AE is recommending to the IHE that the alternative reserve level calculation be adopted. Consequently, regardless whether the council amends its financial policies, the test year level of reserves should be reduced by $20 million to reflect a level that has been determined to be adequate for AE's business operations. Moreover, AELIC requests Your Honor to find that the time between rate cases is not three years but five years. Just as Your Honor's decision involving the recovery of rate case expenses, AELIC requests Your Honor to find and determine that recovery of any under recovered reserves should be over the five years between rate cases.

The second exception in this grouping is a minor one. AELIC is simply urging Your Honor to make the $14.5 million increase in revenues as an adjustment to AE's reserves.

The last exception to this trio involves an adjustment that was not substantially briefed. In the hearing, AE witness Dombrowski admitted that part of the increase to the utility's regulatory charge tariff in FY 2016 was to repay itself back $29 million in costs underlying the regulatory charge that were not covered by the revenues realized from the regulatory charge in previous years. Further Mr. Dombrowski testified that AE utilized reserves to pay these costs that were not covered; and that a goal of the regulatory charge increase in part was to return the $29 million to its working capital reserves.[18] Since AE utilized its FY 2015 unaudited level of reserves,[19] it did not make an adjustment to increase its working capital reserves by this $29 million even though the FY 2016 regulatory charges will cause an increase of its reserves by $29 million before the effective date of the FY 2017 rates. AELIC requests Your Honor to find and determine that the reserves should be adjusted to include this $29 million amount. This amount should be readily ascertainable at the time the Council will be deciding the rates set in this case. See also attached AELIC Ex. No.19.

7. <u>The IHE erred in adopting AE's recommended addition of a seasonal differential Power Supply Adjustment ("PSA") rate because the costs underlying the PSA do not directly vary with a summer peak but vary with fuel price changes, AE's success in utilizing its generation fleet to hedge its market prices, and with market price spikes that accrue throughout the year.</u>

   AELIC will not be adding any additional argument except to point out various factors:

   - AELIC Ex. No. 18 shows that for the test year, the most times AE was faced with 15 minute intervals where the market price was over $200 occurred in December through April. This factor demonstrates the fact that PSA costs are not consistently higher in the summer than in the winter; thereby undercutting support for a seasonal differential;
   - AELIC Ex. No. 6 shows AE employee emails that state that it needed to utilize a three year average to get a PSA seasonal differential because use

[18] Tr. 110 and 111.
[19] See AE Ex. No. 1, Bate Stamp page 093.

of the 2014 data would result in winter rates higher than summer rates. This factor also shows that there is not a consistent connection between high PSA costs and summer consumption;

- AE Ex. No. 1, Bates Stamp p. 378 show that gas prices from 2000 to 2015 are not correlated to summer weather. In fact, Figure 3 shows that gas prices are highest in the winter. As AE discussed, gas prices are correlated to market prices. This fact also shows that there is no evidence to support a consistent correlation between summer and PSA costs.

8. <u>The IHE erred in increasing the residential first tier rates by over $7 million in addition to removing a summer differential from base rates because: it was done without any evidence concerning the conservation effect to the rates; the change results in creating virtually no base rate per kWh differential between the first and second residential rate tiers inside the city limits and creating a first tier rate that is higher than the second tier outside the city limits; fails to acknowledge that small users are cheaper to serve; and it is unequitable to have a group of residential customers (those customers whose usage are within the first tier) have a rate increase and all other customers a rate decrease based simply on rates when the utility is experiencing surplus revenues.</u>

   AELIC briefed this issue extensively in its post hearing brief and incorporate is arguments on this point herein. AELIC will be making the following additional points.

   a. *Conservation Effect of AE's changes were not considered nor did AE attempt to analyze the effect for each of the two changes to residential rates it is proposing*.
      i. Conservation is one of the policies in AE's rate design. AE Ex. No.1, Bates Stamp p. 191
      ii. AE's own study shows AE's current residential rate design with inverted block rates and seasonal base rates "resulted in a significant reduction in energy consumption." AELIC Ex. No.1
      iii. AE's seasonal base rates which increase prices in the summer promote conservation along with AE's inverted block rate design. AELIC Ex. No. 1.

iv. Inverted block rate design means that each successive rate tier is priced higher than the previous tier. AE Ex. No. 1, Bates Stamp p. 194, Tr. p. 591.

v. An inverted block rate design implemented to recover a utility's embedded costs means that at least one tier's rates are set below average cost and at least one tier's rates are set above average cost. Tr. p. 591.

vi. According to AE, its use of seasonal base rates "have increased AE's financial risk because a large portion of its revenue requirement is designed to be recovered in the four summer months." AE Ex. No. 1, Bates Stamp, p. 136

vii. Eliminating the seasonal base rates result under AE's analysis in less financial risk to AE; but the elimination also reduces the energy conservation effectiveness of AE's residential rates.

viii. If AE keeps each residential rate tier "revenue neutral" or utilizes a simple or weighted average of the seasonal ("summer") rate and the winter rate, the resulting rate for each tier will be higher than the current winter rate but lower than the current summer rate.

ix. AE has not provided any evidence concerning the conservation effect of eliminating its summer base rates.

x. Energy conservation is not promoted by increasing the small user rate tier (1-500kWh) because at that level of energy usage customers have little or no room to reduce consumption contrary to a conservation rate design that increases prices at rate tiers where the underlying usage is at a level that customers have room to reduce consumption. ICA Ex. No. 1, Johnson Dir., pp. 80 &81

xi. A residential rate tier averaging approach will increase AE's revenues because the total "winter" kWh usage is greater than the total "summer" kWh usage for the first two tiers and a weighted average should provide for revenue neutrality in the other three tiers. AE Ex. No. 1, p. 1074. (AELIC points out that the additional revenues AE would realize from the first tier could be used to allow AE a little more discretion in choosing a rate between average and weighted average for the remaining tiers.)

xii. AE provided no evidence concerning the conservation effect of its proposed residential tier rates which is troubling because AE is reducing prices in tiers where price can influence consumption and increasing prices in tiers where price cannot influence consumption.

xiii. Reliance on a cost of service study that assigns costs to rate classes for purposes of establishing rates in AE's inverted rate design is inappropriate because rate design involves setting rates based on marginal cost which is above a utility's embedded costs. ICA Ex. No. 1, Johnson Dir., p.80. It is also inconsistent with AE's proposed differential between the 3rd and 5th rate tier which AE stated it set at marginal cost. AE Ex. No. 1, Bates Stamp p. 147. Under an inverted block rate, rate tiers are not set on an embedded cost of service but are designed based on marginal cost concepts. This means some rate tiers are below average embedded cost and some tiers are above average embedded cost. Further, each successive tier is priced higher than the previous tier.

xiv. AE's proposed changes in its residential energy rates causes, when all base rate costs are factored in (this includes the utility's customer charge), the residential base rate per kWh amount is almost the same for the first and 2nd tier rates, and in the case of rates outside the city limits, the residential base rate per kWh amount is greater in the first tier than in the second tier. Consequently, AE's proposed rate changes are contrary to the purpose of an inverted block rate design.

b. *Small users are cheaper to serve.*

In discovery, AE admitted that it costs the utility more to provide services to large user residential customers as opposed to small user residential customers. The attached exhibits explain why this is so. Consequently, AE's current residential inverted block rate structure also reflects that residential small users are cheaper to serve than large users. See attached Exhibits 24, 25, and 26 which show the cost diversities among residential customers.

c. *It is inequitable for a group of customers to realize a rate increase when the utility is experiencing a surplus.*

In this case AE is seeking over a $7 million increase to residential small users (1-500kWh) rates. This is being done even though AE is substantially revising its residential rate design through the elimination of seasonal base rates that it contended posed revenue stability concerns. It is also inequitable because the increase is being done without any analysis of the conservation effect of eliminating the seasonal base rates. A further in equity is the elimination of the effective inverted base rate tier structure for the first and second tier because the increase to the first tier rates are at a level where coupled with the declining nature of the customer charge, the total base rate cents per kWh for the first and second tier are virtually identical.

d. *AE's argument of revenue stability as justification to increase small users' rates by over $7 million is muted when consideration is given to the misperception AE made with its fixed versus variable revenues.*

In its testimony, AE created a figure that showed 75% of its revenues were variable. This figure was used by AE to argue about its revenue stability problems.[20] However, Bates Stamp p. 1071 of AE Ex. No. 1 is a breakdown of AE's revenues by services. What the document reveals is that a substantial portion of its "variable" revenues—over half—are reconcilable. A reconcilable rate is one in which AE is made whole. It has no risk of under recovering its costs because the rate can and will be adjusted to recover whatever unrecovered costs it experienced. AELIC has attached this page and has marked with yellow the services for which AE is guaranteed recovery of its costs. These services are referred to as pass-through rates. Yet AE continues to push for more revenue stability. In this rate case, AE has requested and the IHE has recommended elimination of the seasonal base rate. AE's request was made based on increasing its revenue stability. Before AE makes any further rate design changes (eliminating the residential seasonal base rate will set tier rates higher than winter rates[21] therefore shifting some of the cost recovery responsibility onto the winter time periods), it should measure its

[20] AE Ex. No. 1, Bates Stamp pp. 134 and 135.

[21] Ironically, AE's proposed residential rate for its second tier is set at the winter rate which is contra-indicated for eliminating the seasonal base rate whose apparent intended purpose is to shift some of the cost recovery onto and therefore set higher rates during winter usage. This is also why the base rate effect of AE's proposed rates results in base rate cents per kWh between the first and second tier being virtually identical.

increased revenue stability caused by shifting cost recovery responsibility onto the winter periods.

9. <u>The IHE's recommendation on piecemeal rate making did not address transparency concerns of the parties involving AE's annual rate hearings held between base rate cases.</u>

The IHE correctly confirmed party concerns about piecemeal ratemaking; that is, not looking at all of a utility's costs and revenues but only a portion. AE's regulatory charge is an example of piecemeal ratemaking. Based on AE's presentation of its rate case, the IHE was unwilling to allow parties to review all of AE's costs. The review was limited to base rates and the impact to cost of service. Almost half of AE's costs and revenues come from rates that were not reviewed in this case. While the IHE agreed with intervening parties that the failure to do a thorough review could cause the utility to over recover, the IHE determined this issue was a council decision. The IHE did not discuss the lack of transparency in the annual rate hearings held as part of the City of Austin's budget hearings that parties such as Samsung addressed. See Samsung brief at p. 61.

The issue of transparency is important because it is the cornerstone to good city government. Transparency means that the decision makers are provided relevant and adequate information to make a decision; that the information is provided in an understandable and user friendly manner; and that the public and stakeholders have an adequate and fair opportunity to obtain information on the relevant issue to be decided and opportunity to provide decision makers with information and comments on information they were provided. With this definition as a guideline, recent budget hearings reveal that the annual rate hearings are not transparent. I have attached two exhibits from the rate case that reveal a transparency failure in that relevant and adequate information was not provided the council relating to the utility's annual rate changes. AELIC Ex. 7 shows that AE's August 2015 FY 2016 budget presentation did not include adequate information to determine whether any other of AE's annual rates were also over recovering or were under recovering. Under this August 2015 presentation it would seem that AE had no rate change for any of its

other annual rates (except for the PSA rate). However, AELIC Ex. No. 8 shows that AE over recovered in the implementation of its energy efficiency rates and that the over recovery was almost as much as the under recovery AE was showing as a justification for increasing its regulatory charge by $5 a month for a typical residential monthly bill. AELIC Ex. No. 8 is information that AE did not provide as part of its FY 2016 budget discussion. It is entirely relevant. The details of each annual rate should be provided to the council in a user friendly manner similar to the way the information was reported in response to a citizen request involving AE's annual rates.

10. The IHE erred in neglecting to find that AE's recovery of its street area lighting costs are discriminatory as well as arbitrary and erred in recommending that the inside city street area lighting tariff continue without any adjustments.

AELIC briefed this issue in its post hearing brief and incorporates the arguments herein. AELIC simply adds that it is arbitrary and discriminatory to have the same service provided with different rates. For customers inside the city limits AE is requiring customers to reimburse the utility for past losses but does not require customers taking service outside the city limits to reimburse the utility for past losses. This is fundamentally unfair and discriminatory and there is no rational reason to treat customers provided the same service in such a discriminatory manner.

11. The IHE's recommendations on future studies should have included addressing the demand and usage diversity of the residential class; cost characteristics based on types and sizes of residential dwellings, including multi-family structures and the size of single family homes; the conservation effect of any rate design changes; the effect rate design changes have on a customer's bill, and for clarifying that lifeline energy usage would consider energy needs for heating and cooling.

12. The IHE's recommendations on AE pilot projects should have included recommendation for stakeholder input involving both customers and customer

advocates to greater ensure all factors are considered in the design and implementation of pilot projects.

AELIC briefed this issue and incorporates its arguments herein. AELIC would only add that we are not asking Your Honor to substitute your judgement for the Council; however, we are asking that you comment on the value of stakeholder input in designing and implementing pilot programs—especially ones that affect customer protection standards. As we pointed out in our brief, the lack of customer protections for the prepayment tariff raises health and safety concerns which could have been addressed with a process that provides for stakeholder, EUC, and public input.

PRAYER

WHEREFORE, PREMISES CONSIDERED, AELIC respectfully requests Your Honor to reconsider the points set out above, consider the arguments set out above and reconsider the arguments AELIC raised in its post hearing brief addressing these points; and after reconsideration to find and recommend to the Council that the relief requested by AELIC be granted. AELIC additionally requests such further relief to which it is entitled in law or in equity.

Respectfully Submitted

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CERTIFICATE OF SERVICE

The undersigned certifies that TLSC has served a copy of the attached document upon all known parties of record by email and to the Impartial Hearing Examiner on the 21st day of July 2016

/S/ Lanetta M. Cooper
Lanetta M. Cooper

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2015 COST OF SERVICE STUDY	§	**IMPARTIAL HEARINGS**
AND PROPOSAL TO CHANGE	§	**EXAMINER**
BASE ELECTRIC RATES	§	

AELIC EXHIBIT NO. 7

Description of Exhibit: Part of AE Presentation to Council on FY2016 budget

NXP/Samsung 2-16. Please provide all studies by AE or others done to produce the results of the affordability matrix since 2011.

ANSWER:

Attached to this response are presentations which report the results of Austin Energy's performance against the Affordability Goals since the goals were adopted in February 2011. Also attached is the underlying data used to generate those reports.

See Attachment 1.

Prepared by: BE
Sponsored by: Mark Dreyfus

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FY 2016 Proposed Budget

CITY OF AUSTIN
FOUNDED 1839

August 12, 2015

Budget Presentations:
www.austintexas.gov/finance

CLEAN, AFFORDABLE, RELIABLE ENERGY AND EXCELLENT CUSTOMER SERVICE

Revenue Highlights

Revenue Changes from FY 2014-15 Amended Budget:

Base – $5.1 million increase

- Base rates held flat since FY 2012-13.
- Normalized weather for sales, customer growth 1.3%.

Power Supply Adjustment (PSA) – $70.0 million decrease

- Lower expected load zone market prices due to abundant supplies of natural gas, which lowered prices and forced coal prices lower as well.

Regulatory – $50.9 million increase

- Recover increasing costs of transmission grid build-out and collection of prior year under-recovery.

Community Benefit – No change from FY 2014-15 Budget

- No change to rate.
- Recovers energy efficiency services, street and traffic lighting, and Customer Assistance Program (CAP).

Other Revenue – $6.6 million increase

- Increased chiller revenue resulting from higher number of contracted customers due to growth in the downtown area.

Proposed High Load Factor Primary Voltage Rate

- Customers with demand greater than or equal to 20 Megawatts

3

Regulatory Charge

- Austin Energy's share of the statewide cost of using the transmission grid, as well as managing, expansion and upkeep of the lines.
- Help bring more renewable energy from West Texas to the rest of the state.
- Costs are reviewed, approved and apportioned by the Public Utility Commission of Texas. Other non-discretionary regulatory costs may also be included.

Revenue Highlights

Typical Residential Customer Bill Impact

Inside City of Austin Customer

Typical Monthly Bill	Energy kWh	FY 2015 Rate		FY 2016 Proposed	$ Change	% Change
Customer Charge	Flat Fee	$10.00		$10.00	None	None
Base Electricity Charge	1,000	$ 43.50		$ 43.50	None	None
Power Supply Adjustment (PSA)	1,000	$ 39.45		$ 31.39	($ 8.06)	(20.4%)
Community Benefit Charge (CBC)	1,000	$ 6.65		$ 6.65	$ 0.00	0.0%
Regulatory Charge	1,000	$ 8.30		$ 14.14	$ 5.84	70.4%
Total Monthly Bill	**1,000**	**$107.90**		**$105.68**	**($ 2.22)**	**(2.1%)**

AUSTIN ENERGY'S TARIFF PACKAGE:	§	**BEFORE THE CITY OF AUSTIN**
2015 COST OF SERVICE STUDY	§	**IMPARTIAL HEARINGS**
AND PROPOSAL TO CHANGE	§	**EXAMINER**
BASE ELECTRIC RATES	§	

AELIC EXHIBIT NO. 8

Description of Exhibit: FY 2014 (Audited) 2015 (CYE) + 2016 (budgeted) EE rev. + expenses

Lanetta Cooper

From: Rivas, Luis <Luis.Rivas@austinenergy.com>
Sent: Tuesday, August 18, 2015 5:41 PM
To: Lanetta Cooper
Cc: Dreyfus, Mark
Subject: EE rate - Lanetta Cooper
Attachments: LC 081715.pdf

Dear Ms. Cooper,

This email is in response to your inquiry to Austin Energy. Please find the attached file which contains the responsive information to your request.

If you have any questions please feel free to contact me.

Sincerely,

Luis Rivas | Public Information Office | Austin Energy
721 Barton Springs Road | Austin, Texas 78704 | (512) 322-6306

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From: Lanetta Cooper <lcooper@tlsc.org>
Date: August 17, 2015 at 2:29:01 PM CDT
To: "Dreyfus, Mark (Mark.Dreyfus@austinenergy.com)" <Mark.Dreyfus@austinenergy.com>
Subject: EE rate

Mark:
I am requesting the energy efficiency rate information for FY 2015 and FY 2016 in the attached format. I don't know if AE is anticipating having imputed revenues from industrial and large commercial customers who were on special contracts until this past year (I think some industrial customers still are on them); so please note that for me so I will know. To the extent the estimated revenues from FY 2016 are not as high as the estimated revenues for FY 2015 (which includes imputed revenues from the special contract customers), please explain why the estimated revenues are reduced.

As in my previous request, I am asking for it in document form as opposed to a telephone call so I can properly evaluate the info. It may lead to a phone call once I see the data. I assume that AE will be responding as requested because I have not heard from the person you would say would contact me. Also, even though I have left two phone messages requesting you call me, I haven't heard from you either.

Once again, if you have questions or need more than the ten day turn around, please contact me. As you know this information is related to this upcoming battle and rate hearings.

Thanks so much. Lanetta.

Lanetta M. Cooper
1.512.477.6000

<Est.FY 2014 EE revenues and expenses.pdf>

Austin Energy
Energy Efficiency Revenues and Expenses
CYE 2015 and Forecast 2016

A.

	FY 2015 CYE Expenses	FY 2015 CYE Revenues	(Over)/Under Recovery	Non Recoverable (until contract expiration)	Total Recoverable
Community Benefit Charge:					
Energy Efficiency	$ 36,014,758	$ 35,570,403	$ 444,355	$ (5,870,160)	$ (5,425,805)

	FY 2016 Forecast Expenses	FY 2016 Forecast Revenues (B)	(Over)/Under Recovery	Non Recoverable (until contract expiration)	Total Recoverable
Community Benefit Charge:					
Energy Efficiency	$ 34,761,618	$ 37,368,032	$ (2,606,414)	$ (4,636,878)	$ (7,243,292)

B. The FY 2016 forecasted revenue estimates include customers whose contract has expired.

C. This schedule does not include the adjustment proposed by the EUC to the Energy Efficiency Services charge.

Lanetta Cooper

From: Rivas, Luis <Luis.Rivas@austinenergy.com>
Sent: Friday, May 22, 2015 4:13 PM
To: Lanetta Cooper
Cc: Dreyfus, Mark; Jambor, Elizabeth; Kuehn, Denise
Subject: FW: Request for FY 2014 EE budget results
Attachments: LC RFI _5-21-15_Ratemaking Questions 1_FY14 (4).pdf

Dear Ms. Cooper,

Please find the attached file which contains the audited 2014 EE budget figures.

Feel free to contact me with any questions.

Sincerely,

Luis Rivas | Public Information Office | Austin Energy
721 Barton Springs Road | Austin, Texas 78704 | (512) 322-6306

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From: Dreyfus, Mark
Sent: Monday, May 18, 2015 5:17 PM
To: Lanetta Cooper
Cc: Kuehn, Denise; Jambor, Elizabeth; Rivas, Luis
Subject: RE: Request for FY 2014 EE budget results

Hi Lanetta,
I will log this in as a PIR. Luis Rivas will be in touch to be sure that we are clear as to the specific request.
Thanks Mark

Mark Dreyfus | Vice President, Regulatory Affairs & Corporate Communications | Austin Energy
721 Barton Springs Rd. | Austin, TX 78704-1145 | (512) 322-6544 (office)

	Audited FY 2014 Expenses	Audited FY 2014 Revenues	(Over)/Under Recovery	Non Recoverable (until contract expiration)	Total Recoverable
Community Benefit Charge:					
Energy Efficiency	$ 32,745,229	$ 34,256,372	$ (1,511,143)	$ (5,527,605)	$ (7,038,748)

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AELIC EXHIBIT NO. 19

Description of Exhibit: Regulatory Charge underrecovery + relationship to working capital

AELIC 9-5 Volume 1, p. 542 of the City of Austin's approved budget for FY 2016 states that AE's regulatory charge rates were increased in part to recover "under-recoveries" of costs that AE seeks to be recovered by its regulatory charge rates. What was the amount of these "under-recovered" costs AE included in its calculated FY 2016 regulatory charge rates for recovery that were approved by the City of Austin for FY 2016. What is your understanding of the meaning of "under-recovery" of costs as used in the FY 2016 COA approved budget language at p. 542 in discussion of the increase in regulatory charge rates.

ANSWER:

The under-recovered costs included in the FY 2016 regulatory rates are $29M. The under-recovery as used in Volume 1, p.542, refers to net regulatory costs not fully recovered since the inception of the regulatory charge.

Prepared by: CG
Sponsored by: Mark Dombroski

AELIC 9-6 Over what FY time periods did AE incur the "under-recovered" costs included for recovery in AE's approved FY 2016 regulatory charge rates?

ANSWER:

The under-recovery of regulatory costs included in the FY 2016 regulatory charge were incurred in FY 2013-2015.

Prepared by: CG
Sponsored by: Mark Dombroski

AELIC 9-7 Please identify the amount of "under-recovered" costs identified in RFI No.9-6 and 9-5 by each FY.AE identified in RFI No. 9-6.

ANSWER:

Regulatory Charge Under Recovery by Fiscal Year

FY 2013	FY 2014	Est. FY 2015
$ 1,777,566	$ 13,891,597	$ 13,666,816

Prepared by: CG
Sponsored by: Mark Dombroski

AELIC 9-8 For each FY identified in RFI No. 9-6, was AE able to cover the "under-recovered" costs, in whole or in part, referenced in RFI No. 9-7 in the FYwhen the costs were incurred. (In other words, was AE able to pay the "bills" left unpaid from revenues realized from its regulatory charge rates).

ANSWER:

Yes. See AE's response to AELIC 9-9.

Prepared by: CG
Sponsored by: Mark Dombroski

4

AELIC 9-9 If the answer to RFI 9-8 is yes, please explain how AE was able to cover the costs, in whole or in part, of the "under-recovered" costs referenced above for each FY identified in RFI No. 9-6. In your explanation please address where the funds AE used to cover the costs came from in its business operations (such as account entry, a named reserve(s), operating balance, etc) as well as the amount of the cost "covered" in the FY.

ANSWER:

Austin Energy paid for the under-recovered costs using working capital funds in the fiscal year in which they were incurred. At times, Austin Energy is unable to fully pass on its costs which further illustrate the need for appropriate levels of cash reserves. The ability to pass on costs is constrained by the Affordability Goals.

Prepared by: CG
Sponsored by: Mark Dombroski

AUSTIN ENERGY'S TARIFF PACKAGE:	§	**BEFORE THE CITY OF AUSTIN**
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AELIC EXHIBIT NO. 24

Description of Exhibit: Diversity of Residential Meters

AELIC 1-14 Please identify each type of meter owned, maintained and operated by AE for residential customers including meters to measure a customer's usage for charging electric vehicles and meters that can either measure usage from the grid and usage from solar distributed energy to the grid or measure usage from solar distributed energy, and meters to measure usage to the customer from the grid.

SUPPLEMENTAL ANSWER:

In addition to those meters identified in Austin Energy's initial Response to AELIC RFI No. 1-14 and as indicated in AE's Response to AELIC RFI No. 3-3, AE also uses Demand, Simple-D, and TOU-R-Net meters for certain residential customers.

In summary, Austin Energy uses the following types of meters to register residential energy usage:

SIMPLE
PV
NET (also known as "S-Net")
TOU (Time of Use)
EV
Demand
Simple-D
TOU-R-Net

Prepared by: JL
Sponsored by: Elaina Ball

TLSC 1-15. For each type of meter identified in RFI No. 1-14, please provide the following:

a. The average cost of the meter; and
b. The number of meters included in the cost of service.

ANSWER:

a. The current cost for the meter types listed in TLSC 1-14 are as follows

SIMPLE $160
PV $160
NET $160
TOU (Time of Use) $169
EV $169

b. The information that is being requested within 'b' can be found within the 'AE RFP' model under sheet name "WP F-6.3". Or in 'Austin Energy's Tariff Package' for 'Cost of Service Model – Redacted' at page 186 of 347 (Bates stamp 945).

Prepared by: CM/JL
Sponsored by: Elaina Ball / Mark Dombroski

AELIC 1-15 For each type of meter identified in RFI No. 1-14, please provide the following:

A. The average cost of the meter; and
B. The number of meters included in the cost of service.

SUPPLEMENTAL ANSWER:

A. The current cost for the additional meter types listed in AE's Supplemental Response to AELIC RFI No. 1-14 are as follows:

Demand $226 to $396
Simple-D $160
TOU-R-Net $169

Prepared by: CM/JL
Sponsored by: Elaina Ball / Mark Dombroski

AELIC 7-21 For each meter type identified in your response to AELIC RFI No. 1-14 to AE, please provide the following:

A. A brief explanation of how AE uses the meter to provide service to residential customers;
B. How the meter is different from the other types of meters identified

ANSWER:

Below, Austin Energy includes information for the meter types included in AE's Supplemental Response to AELIC's RFI No. 1-14.

Meter Type	(A)	(B)
Simple	Measures the kWh delivered to the resident	This is the most common type of residential meter
PV	Measures the kWh generated by the customers' photovoltaic array	This meter is used by Value of Solar customers
S-NET (Simple Net)	Measures the kWh delivered to the distribution grid and received by the customer from the distribution grid	This meter is used by Value of Solar customers
TOU (Time of Use)	Measures the kWh delivered to the resident in accordance with a Time of Use schedule	Differs from simple meters in that is collects reading data by time of use
EV	Measures the kWh delivered to the customer's electric vehicle charging station	This meter is used by the plug-in electric hybrid pilot
Demand	Measures the kWh delivered to the resident	This meter is used by customers with higher loads
Simple-D	Same as a Simple Meter.	Can disconnect service remotely
TOU-R-Net	Measures net energy in accordance with a Time of Use schedule	Combines the functionality of a TOU and S-Net meter

Prepared by: JL
Sponsored by: Elaina Ball

AELIC 7-19 In AE's response to AELIC RFI No.3-3 to AE, a "Demand meter" and an "S-Net meter" were identified as in service to residential customers receiving three-phase electric service. In its response to AELIC RFI No. 1-14 AE did not identify a "demand meter" as a meter maintained and operated by AE for residential customers. Also, in that same response, AE identified a Net meter, not a S-Net meter. Please explain how the "demand meter" for residential customers receiving three-phase electric service is used by AE to provide service to these customers. In your explanation, please explain why this meter was not identified in your response to AELIC RFI No. 1-14 and what the average cost of this meter is. Please also identify where this meter is located in AE's COS.

ANSWER:

The Demand meter type was inadvertently omitted from the response to AELIC 1-14 and AELIC 1-15; please see Austin Energy's Supplemental Response to AELIC's RFI No. 1-14 and 1-5. The average cost for the Demand meter type used for residential service ranges from $226 to $396. Demand meters are a meter make and model that is capable of registering energy at a higher voltage. A residential Demand meter type collects the same meter register data as the Simple meter type. Demand meters are installed on a residential premise based on the size of their service and load.

The Cost of Service does not distinguish between meter types by customer class. The COS uses the average cost of the most common meter. The average cost of meters is shown in Work Paper F-6.3, line 6. The supporting document for the meter cost during the Test Year has been provided in AE's Response to NXP/Samsung RFI No. 5-15.

Prepared by: JL
Sponsored by: Elaina Ball

AELIC 7-22 Does AE maintain and operate any other meters for residential customers than those identified in AELIC RFI Nos.3-3 and 1-14. If so, please list each such meter; provide a brief explanation of how AE uses the meter to provide service to residential customers; the average cost for the meter; and how the meter is different from the other types of meters identified in responding to the AELIC RFIs referred to in the previous sentence. Please also identify where the meter is located in AE's COS.

ANSWER:

Please refer AE's Supplemental Response to AELIC 1-14. In addition to those meter types originally identified in AE's Response to AELIC RFI Nos. 1-14 and 3-3, AE operates Simple-D and TOU-R-NET meter types for residential customers. These meter types are variants of the Simple and TOU meters previously identified.

The Simple meter types are currently being replaced with a Simple-D meter type. The Simple-D meter types perform the same functions as Simple meters. Simple-D meters have the added functionality of a remote disconnect. The average cost of the Simple-D meter is the same as shown for the Simple meter type in AE's Response to AELIC RFI No. 1-15.

The TOU-R-Net meter type is a variant of the TOU meter listed in AE's Response to AELIC RFI No. 1-14. There is no difference in cost between the TOU-R-Net and TOU residential meters. The TOU-R-Net meter measures the kWh delivered to the distribution grid by the customer and received by the customer from the distribution grid. Additionally, the TOU-R-Net meter also collects the meter read by the time of use schedule. This new meter type has not been widely deployed.

The Simple-D and TOU-R-Net meter types were not use during the test year. Therefore, they are not in the COS.

Prepared by: JL
Sponsored by: Elaina Ball

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

ANSWER:

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

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

Prepared by: BK
Sponsored by: Elaina Ball

ICA 3-8 For the residential class, S1 class, and S2 class, provide the estimated installed cost for mechanical meters vs. the smart meters currently used by Austin Energy. Please show the costs in comparable (same year) dollars.

ANSWER:

Meters are not classified by customer class. See table below for the current population of meters. The table below excludes CT (current transformer) meters, as these types of meters are associated with our larger commercial customers (S3 class).

Class	Meter Forms	Meter Count		Meter Cost		Installation Cost	
		Manual	AMI Meter	Manual	AMI Meter	Manual	AMI Meter
Residential	2S AX or AL for AMI Meters	299	384631	$18	$160.00	$30.00	$30.00
Small/Medium Commercial	2S RXR, 2S CL 320 AXR, 12S AXR-SD	0	36128		$214.33		$115.00

Prepared by: PC
Sponsored by: Elaina Ball

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AELIC EXHIBIT NO. 25

Description of Exhibit: Infrastructure cost diversity

AELIC 3-17. In designing a distribution system for a residential development, does AE consider:

A. The size(s) of the residential structure(s) (Residential structures would include outbuildings that will be using electricity such as guest houses, pool houses, and garage/shops.)
B. The size of the property (such as lot size) where the residential structures are located;
C. The electrical demand of the residential structures and improvements such as swimming pools, hot tubs, and landscaping.
D. The geology of the subdivision.

ANSWER:

A. Yes.
B. Yes.
C. Yes.
D. Yes.

Prepared by: MP
Sponsored by: Elaina Ball

AELIC 3-18. If the answer to RFI No. 3-17 is yes, in whole or in part, please briefly explain how each consideration is relevant to the design of the distribution system, including cost considerations.

ANSWER:

A. The size of the residential structure typically relates to the size of the load. All load requirements must be known to adequately size the electrical facilities.

B. The size of the property and the location of the residential structures implicate design criteria. For example, buildings built further into properties require longer power lines to provide power to the meter.

C. The electrical demand of the residential structures and improvements often relate to the demand of the load. Electrical facilities must be sized to supply peak demand.

D. The geology of the subdivision, such as grade, is a factor in the type of electrical facilities required such as pole heights, framing, equipment locations, etc.

Prepared by: MP
Sponsored by: Elaina Ball

AELIC 7-16 In response to AELIC RFI No. 3-18 AE responded without explaining how each consideration impacted AE's load making the response unclear. Moreover, AE failed to address the cost considerations requested to be addressed. Please provide what cost considerations are involved in AE's design of a distribution system for each consideration identified in AELIC RFI No. 3-17 to AE. For instance, AE responded in AELIC RFI. No. 3-18 A saying the "size of the residential structure typically relates to the size of the load." What does this mean? Does this mean the larger the house, the greater the demand. How does this factor impact costs of the distribution system?

ANSWER:

A. With regard to the size of a residential structure, AE takes into account many factors when designing a distribution system for a residential development, including:

- The number of structures on a property (e.g., main house, guesthouse, guard house, etc.);
- The size of each structure (in square feet);
- The use type of the structures (e.g., single family, multifamily, garage workshop, guest house, pool house, etc.);
- The fuel types used on the property (e.g., all electric or dual fuel – electric & gas); and
- Whether there are any specialty loads on site (e.g., large workshop equipment).

For example, a 5,000 square foot home typically uses more power than a 2,000 square foot home. All other variables being equal (fuel type, use type, etc.), the difference can typically be attributed to air conditioning load; thus, a larger building requires more electricity to cool the larger volume of air as compared to a smaller building. In such instances, a larger home may require higher rated infrastructure — such as a 320 amp meter (vs. a 200 amp meter), larger service wire, larger transformer, etc. — to meet the demand of the larger infrastructure. This higher rated infrastructure can lead to increased cost; however, under the City Council's current line extension policy, 100% of these costs are paid upfront by the customer requesting this service.

B. With regard to the size of the property on which the structures are located, the location of the residential structures compared with the location of the service feed is used in determining the amount of infrastructure that is required to provide service. For example, buildings erected further away from the source of electricity typically require longer power lines to provide power to the meter at the structure. This increases the cost to provide power because more wire and/or poles are required due to the longer distance between source and meter; however, under the City Council's current line extension policy, 100% of these costs are paid upfront by the customer requesting this service.

C. With regard to the demand of the structures, AE must take into consideration the electrical demand of the residential structures and whether there have been any improvements made on the property — such as swimming pools, hot tubs, and landscaping — when sizing electrical infrastructure. These higher demand loads often increase the infrastructure required to serve the customer (such as wire, poles, transformers, meter, etc.) and therefore, increase installation cost. However, under the City Council's current line extension policy, 100% of this cost is paid upfront by the customer requesting this service.

D. With regard to the geology of the subdivision, Austin Energy considers various geological factors when designing the facilities that are required to serve new customers. Infrastructure, such as pole heights, framing, and other equipment as well as the locations of the infrastructure may all be impacted by the geology of the subdivision. In cases, where there is a large grade change — i.e., a hill or valley — more poles may be required than normal in order to maintain National Electric Safety Code clearances. The additional infrastructure may increase the installation costs; however, under the City Council's current line extension policy, 100% of this cost is paid upfront by the customer requesting this service.

Prepared by: DS
Sponsored by: Elaina Ball

TLSC 1-25. At App. E, E-1 (Bates Stamp p. 372) AE references "three-phase electric service" for residential customers. Could you please explain what the term "three-phase electric service" is and how it is different from a residential customer receiving traditional electric service?

ANSWER:

Three-phase service refers to electric energy that is transmitted by three or four wires to the customer. Relatively high voltage or very large load customers usually receive three-phase power, compared to single-phase service where a facility (e.g., house, small office) has two energized wires coming into it. Typically, single-phase service supplies smaller needs of 120V/240V, requires less and simpler equipment and infrastructure to support. Single-phase service tends to be less expensive to install and maintain.

Prepared by: CM
Sponsored by: Elaina Ball

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AELIC 7-15 What additional installation and infrastructure costs are incurred to serve a residential value of solar customer versus a non-value of solar residential customer? In your response, please address how if at all additional costs are incurred relating to meters; what elements/components of the distribution system are impacted and how each element/component is impacted; and how, if at all AE's operating software for billing, distribution, and interactions with the grid are impacted, including both the embedded costs and the marginal operating costs. (Reference: AE Response to AELIC RFI No. 3-16(C))

ANSWER:

The additional installation and infrastructure costs Austin Energy incurs for serving a Value of Solar customer versus a non-Value of Solar customer are approximately $322 in one-time expenses and $1.03 in on-going monthly costs.

Of the $322 in estimated one-time additional costs, $241 is related to the cost of purchasing and installing the requisite VOS meters. This estimated expense includes the cost of the meters as well as staff salary and benefit expenses. $81 is associated with programming the meter reading system to pull data from the VOS meters. This estimated expense includes staff salary and benefit expenses. The $1.03 of on-going monthly additional expenses is related to monthly meter reads of the VOS meters.

Components of the distribution system are normally positively impacted by distributed residential solar because the generation resource can offset load on the distribution components and thereby reduce overall distribution system losses. Only in cases of high concentrations of distributed solar — such that the localized capacity of distributed solar exceeds the capacity of existing distribution components — is the system impacted negatively. In these cases, the VOS customer is responsible for 100% of the cost to upgrade the component so that the system is not impacted.

Other costs for maintenance and billing are de minimis because meter maintenance or replacements are rare and the billing system applies VOS credits to an existing residential account and generates a credit on a bill which exists regardless of whether solar has been connected or not.

Prepared by: DS
Sponsored by: Elaina Ball

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AELIC EXHIBIT NO. 26

Description of Exhibit: Infrastructure Residential Demand Estimation

3.4 Residential Electrical Demand Estimation

Accuracy in estimating demand comes from studying the job, not by using the section guidelines as the sole criteria. The engineer/designer must identify such factors as customer business hours, actual size and type of the customer's equipment, duty of the equipment when the load is on, and the intended use of the equipment, especially regarding air conditioning load. The engineer/designer should meet with the electricians, electrical contractors, consulting engineers, plant managers, etc. representing the customers for whom the service is to be provided to gather and verify this information. The engineer/designer should also look at the demand requirements by studying electric consumption history of similar loads.

3.4.1 Residential Service Demands

The engineer/designer should use the appropriate method to estimate the demand for residential services, which includes condominiums and apartments. The majority of the single and multifamily residential loads will be determined by the kVA demand per square footage of living space tables from Table 3.3 to Table 3.6 included in this Section. These tables provide a quick, easy design approach to select the appropriate transformer size based on the number of homes and the average square footage of the homes to be served. Transformer sizing guidelines for residential distribution are also included in this section.

Maximum Demands for Residential Services. Table 3.3 through Table 3.6 list maximum kVA demands for groups of single and multiple residential dwelling units. These tables give the average peak demand for single and multifamily dwelling units for different square footage ranges. The maximum kVA demands shown in Table 3.3 through Table 3.6 for any group of dwellings should be used to size distribution equipment such as distribution transformers and secondary and service cables.

IMPORTANT: Each part of the secondary side service (the service, the secondary, and the transformer) should be sized separately for the specific maximum demand that it will see, i.e., maximum demand for the service for one residence will be different from the maximum demand for the secondary serving two residences, and these will differ still from the maximum demand for the transformer serving eight residences because of load diversification.

EXAMPLE

Let's consider a transformer that serves eight 3,000 ft^2 residences, with two secondary runs serving two 3,000 ft^2 residences' services each, and four services from the transformer directly to the residences. All the 3,000 ft^2 residences are mixed fuel. The maximum demand kVAs used to size the three parts of the service/secondary/transformer are as follows and can be read directly from Table 3.3

The transformer will see eight residences or 79 kVA.

Each secondary run will see two residences or 22 kVA (or 92 amps at 120/240 volts).

Each service will see one residence or 12 kVA (or 50 amps at 120/240 volts).

Table 3.3 Maximum kVA Demands for Single Family Residences with Gas Service

# of Homes	Average Square Footage of Homes with Gas Service								
	≤1000	1001-1500	1501-2000	2001-2500	2501-3000	3001-3500	3501-4000	4001-4500	4501-5000
1	6	7	8	10	12	14	18	22	26
2	11	13	15	18	22	26	33	39	48
3	16	19	22	26	32	37	48	57	68
4	21	25	29	34	42	49	61	75	88
5	26	30	35	42	52	71	75	93	108
6	30	35	41	49	61	82	91	111	NA
7	35	41	48	56	70	93	106	NA	NA
8	40	46	55	64	79	105	NA	NA	NA
9	45	52	61	72	89	NA	NA	NA	NA
10	50	58	68	80	99	NA	NA	NA	NA

*Single Family Residence with Gas Service for hot water heater, heating furnace, and cooking range

Table 3.4 Maximum kVA Demands for Single Family Residence with All-Electric Service

# of Homes	Average Square Footage of All-Electric Homes								
	≤1000	1001-1500	1501-2000	2001-2500	2501-3000	3001-3500	3501-4000	4001-4500	4501-5000
1	12	14	16	19	23	28	32	36	40
2	21	24	29	33	41	48	55	58	70
3	30	34	42	48	57	66	74	76	83
4	39	44	55	63	72	82	93	96	106
5	48	54	68	78	84	98	111	116	NA
6	56	63	81	93	98	112	NA	NA	NA
7	64	72	92	102	108	NA	NA	NA	NA
8	72	81	105	118	NA	NA	NA	NA	NA
9	81	91	NA	NA	NA	NA	NA	NA	NA
10	90	101	NA	NA	NA	NA	NA	NA	NA

Table 3.5 Maximum kVA Demands for Multifamily Residence with Gas Service

With Gas*	Average Square Footage of the Units					
# of Units	≤ 500	501-1000	1001-1250	1251-1500	1501-1800	1801-2000
1	3	5	7	9	12	13
2	7	9	11	17	21	25
3	8	12	15	22	27	37
4	11	15	19	27	34	47
5	12	18	24	32	38	55
6	14	21	27	37	46	63
7	15	24	30	42	52	70
8	17	27	33	48	58	77
9	18	30	36	53	64	83
10	20	33	39	59	70	90
11	22	36	44	64	76	97
12	24	39	47	70	82	104
13	26	42	51	75	88	111
14	28	45	55	81	94	118
15	30	48	59	86	100	125
16	32	51	62	92	106	132
17	34	54	66	97	112	139
18	36	57	70	103	119	146
19	38	60	74	109	126	153
20	40	63	78	114	134	160
21	42	66	82	120	143	167
22	44	69	86	125	149	174
23	46	72	90	131	156	181
24	48	75	94	137	162	NA
25	50	78	99	142	169	NA
26	51	81	103	148	175	NA
27	53	84	108	152	182	NA
28	55	87	112	157	NA	NA
29	57	90	117	163	NA	NA
30	59	93	121	169	NA	NA

*Multifamily Residence with Gas Service for hot water heater, heating furnace, and cooking range

Table 3.6 Maximum kVA Demands for Multifamily Residence with All-Electric Service

# of Units	Average Square Footage of the All-Electric Units					
	≤500	501-1000	1001-1250	1251-1500	1501-1800	1801-2000
1	4	11	13	14	15	16
2	9	18	21	23	26	28
3	11	25	28	31	36	39
4	14	30	33	37	45	51
5	15	35	38	43	52	60
6	18	39	43	52	59	68
7	20	43	48	57	66	75
8	23	47	52	62	72	82
9	24	51	56	67	78	88
10	26	54	60	72	84	94
11	29	58	64	77	90	101
12	32	62	69	82	96	107
13	34	65	74	87	102	113
14	37	69	78	92	108	120
15	40	72	82	97	114	126
16	42	75	86	102	120	134
17	45	79	91	106	126	141
18	48	83	95	110	132	147
19	50	86	99	115	138	153
20	53	89	103	119	145	159
21	55	92	108	124	151	163
22	58	96	112	129	157	170
23	61	99	117	133	163	176
24	63	102	121	138	169	182
25	66	106	125	143	175	NA
26	69	109	129	148	181	NA
27	71	113	133	153	NA	NA
28	74	117	137	158	NA	NA
29	77	121	141	163	NA	NA
30	79	123	145	168	NA	NA

3.4.2 Demand Factors for Large Residential Loads

In the case of large custom homes, the demand can be determined from loads and factors in Table 3.7. These demand factors and connected loads (kW) shall be used in calculating service demands and in determining transformer requirements and service requirements for a single large custom home served from a single transformer - See Residential Demand Method 1. See Residential Demand Method 2 for extrapolated square footage method and Residential Demand Method 3 for diversifying several large services from a single transformer.

Table 3.7 Demand Factors for Various Residential Loads in Custom Single Family Homes (>5,000 ft^2)

Demand Categories	Typical Demand Factor	Connected Appliance	Connected kW Per Unit
Lights	0.5	Internal lighting	4-6
TV's, PCs, etc.	0.5	Electronic equipment	3-6
Air conditioning (or heat pump)*	0.7	3 to 7-1/2 ton 1Φ Central Unit, single or multiple units	1.3 kW/ton
Major appliances	0.4	Range (use actual unit load)	8-12 ea.
		Water heater	4.5 ea.
		Water heater (quick recovery)	9 ea.
		Clothes dryer	5.5 ea.
		Dishwasher	1.2 ea.
Exterior loads (use actual connected load)	0.5	Tennis court lighting	varies
		Swimming pool equipment	varies
		Exterior lighting	varies
Convenient outlets	0.1	Undesignated use outlets	varies
Other Loads	0.3	Wine cellar, Sauna, Small motor load, and other	varies

*See Section 3.4.4 for all-electric homes; use the total kW for the electric heat instead of a/c to determine the maximum demand.

The demand for custom homes above 5,000 ft^2 can be calculated using Table 3.7 as follows:

Total Customer kW Demand = connected $load_1$ x demand $factor_{1\ (lights)}$

+ connected $load_2$ x demand $factor_{2\ (electronic\ equipment)}$
+ connected $load_3$ x demand $factor_{3\ (a/c)}$
+ connected $load_4$ x demand $factor_{4\ (range)}$
+ connected $load_5$ x demand $factor_{5\ (tennis\ courts,\ pool)}$
+ connected $load_6$ x demand $factor_{6\ (undesignated\ use\ outlets)}$
+ connected $load_7$ x demand $factor_{7\ (other)}$

Connected load is the total connected load in kW for each appliance category shown in the ESPA and the builder's plans. Typical kW demand factors are shown in Table 3.7.

(Demand factor is the ratio of peak kW demand to the total connected kW load.)

Residential Demand Method 1- Estimating Residential Demand Using Customer Plans and Operational Needs

The following provides an example of estimating the demand for a 7,000 ft^2 multi-fuel residence plus swimming pool using the information provided in Table 3.7 and the following load schedule:

Load Schedule Category	Connected Load (kW)
Lighting	6.5 kW
Electronic	6.5 kW
Air conditioning	15.0 kW
Major Appliances	38.0 kW
Exterior	6.0 kW
Outlets	15.0 kW
Other	15.0 kW

The above figures are provided with or can be determined from the ESPA and building plans provided by the customer's consulting engineer (not shown).

Customer metering demand (kW) = Sum of connected load x demand factor (from Table 3.7) for each type of load

Category	Load (kW)	Diversity Factor	DF x Connected kW		Estimated Metering kW
Lighting	6.5	50%	0.5 x 6.5 kW	=	3.25 kW
Electronic	6.5	50%	0.5 x 6.5 kW	=	3.25 kW
Air Conditioning	15.0	70%	0.7 x 15.0 kW	=	10.5 kW
Major Appliances	38.0	40%	0.4 x 38.0 kW	=	15.2 kW
Exterior	6.0	50%	0.5 x 6.0 kW	=	3.0 kW
Outlets	15.0	10%	0.1 x 15 kW	=	1.5 kW
Other	15.0	30%	0.3 x 15 kW	=	4.5 kW
			Total customer kW or metering demand	=	41.2 kW

Customer load demand (kVA) = total metering demand (kW)/ Power Factor*

(Use PF = 0.9 for residential)*

$$= \frac{41.2\,\text{kW}}{.9} = 45.78\,\text{kVA}$$

If this customer is the only customer connected to the transformer, 45.78 kVA is the maximum demand seen by both the service and the transformer.

Residential Demand Method 2 - Estimating Residential Demand for a Large Home Using Square Footage

When determining the expected demand for homes above 5,000 ft^2 (but less than 10,000 ft^2) that are a part of a subdivision of similar very large homes where the developer does not have available the builders' exact plans at the time the AE infrastructure is installed, the designer should extrapolate the demand load given for 5,000 ft^2 houses in Table 3.3 and Table 3.4 to determine the expected demand *plus* allow for (Residential Demand Method 1) extra large/untypical residential loads.

The following provides an example of estimating the demand for a new 7,000 ft^2. multi-fuel residence using average demand per square foot for smaller homes given in Table 3.3.

For a multiple-fuel home of 7,000 ft^2, use Table 3.3 with Residential Demand Method 1 as follows:

The demand for a home of 7,000 ft^2 =

$$(1)\text{kVa demand for a } 5{,}000\ \text{ft}^2 \text{ home from table} \times \frac{7{,}000\ \text{ft}^2}{5{,}000\ \text{ft}^2} +$$

$$(2)\ \text{Extra large/Untypical using Residential Demand Method}$$

$$(1)\ \text{Sq. Ft. Demand for home} = 26\,\text{kVA} \times \frac{7000}{5000} = 26 \times 1.4 = 36.4\,\text{kVA}$$

$$(2)\ \text{Extra large/Untypical} = (6\,\text{kW Ext. Light} \times .5\,\text{DF}) + (15\,\text{kW Other} \times .3\,\text{DF})$$

$$= 3 + 4.5 = 7.5\,\text{kW or } 8.3\,\text{kVA for PF} = .9$$

Total demand for this home of 7,000 ft^2 = 34.6 kVA + 8.3 kVA = 44.7 kVA

44.7 kVA is seen by both the service and the transformer.

Residential Demand Method 3 - Estimating Diversified Residential Demand for Several Large Homes

The following provides an example of estimating the diversified demand for four new 7,000 ft^2. multi-fuel residences served from a single phase transformer by determining a diversification factor using the demand information for 5,000 ft^2. homes from Table 3.3 and applying this factor to the larger homes of less than 10,000 ft^2 as follows in (1) and (2):

(1) The diversification factor for four homes larger than 5,000 ft²

$$= \frac{\text{kVA demand for 4 - 5,000 ft}^2\text{ houses}}{4 \times \text{kVA demand for 1 - 5,000 ft}^2\text{house}}$$

$$= \frac{88\,\text{kVA}}{4 \times 26\,\text{kVA}} = \frac{88}{104} = .846$$

(2) Determining the diversified demand for four 7,000 sq. ft. homes using this factor.

If four homes of 7,000 ft² are to be served directly from the same transformer, use diversified demand factor determined in (1) times the kVA demand for one 7,000 ft². home (from either Residential Demand Method 1 or Residential Demand Method 2) times four (for the 4 houses being served) to determine the diversified demand as follows:

Total diversified demand for 4-7,000 ft² Homes (using the results of Residential Demand Method 1)

$$= 45.78\,\text{kVA} \times 4 \times \text{ Diversification factor } = 45.78\text{kVA} \times 4 \times .846 = 154.92\text{kVA}$$

3.4.3 Residential 1-Phase Transformer Loading

Once the total customer demand is determined, select the transformer size from Table 3.8 or Table 3.9.

Table 3.8 Recommended Loading Ranges for 120/240 V 1Φ Padmount Transformers

Transformer kVA Nameplate Rating	Initial kVA Loading Range	Change-out kVA Loading Point
25	0-30	35
50	31-60	70
75	61-90	100
100	91-120	135
167	121-200	225
250*	201-300*	335**

*Use only for change-outs of overloaded 167 kVA single-phase transformers and only IF fuse coordination can be maintained.

**Change out option: NONE. Have customer split his load and take another point of service.

Table 3.9 Recommended Loading Ranges for 120/240 V, 1 Φ Overhead Transformers

Transformer kVA Nameplate Rating	Initial kVA Loading Range	Change-out kVA Loading Point
10	0-13	16
15	14-20	23
25	21-32	38
50	33-65	75
75	66-92	105
100	93-125	140
167	126-210	233*

*Change out option: NONE. Have customer split his load and take another point of service.

3.4.4 Residential Air Conditioning

(Loading @ 95 °F and PF = 0.90)

Table 3.10 provides typical kVA demands for various sizes of residential air conditioning units.

Table 3.10 Residential 1 Φ Central Air Conditioning Equipment Demand Load Data

Tons	BTU Rating	kVA Demand
0.5*	6,000	1.0
0.75*	9,000	1.6
1.0*	12,000	2.2
1.5*	18,000	3.0
2.0	24,000	2.9
2.5	30,000	3.5
3.0	36,000	4.2
3.5	42,000	5.0
4.0	48,000	5.9
5.0	60,000	6.9
7.5	90,000	8.9

* Room Air Conditioners

3.5 Residential Revenue Estimation

Part of the design process is to estimate the revenue AE would receive from a particular residential customer or development in order to determine if the revenue to AE is sufficient to allow the construction of the necessary service facilities at no cost to the customer or if the customer should

AELIC 10-12 If the answer to No. 10-11 is yes, please identify each document, including memos, power point presentations, emails and such other forms of communication, AE is aware of that it has provided the Electric Utility Commission, the Austin City Council and/or the Austin Energy Utility Oversight Committee relating to and/or in conjunction with these presentations.

ANSWER:

Document Name	Document Description	Document Date
20110124 DPA Report	January 2011 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections	Jan. 24, 2011
20110127 Council Ordinance No. 20110127-004	Ordinance amending City Code Chapter 15-9 as it relates to utility disconnection moratoriums during extreme weather conditions.	Jan. 27, 2011
20110228 DPA Report	February 2011 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Feb. 28, 2011
20110411 DPA Report	April 2011 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	April 11, 2011
20110504 DPA Report	May 2011 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	May 4, 2011
20110620 DPA Report	June 2011 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	June 20, 2011
20110718 DPA Report	July 2011 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	July 18, 2011
20110718 EUC Minutes	Minutes of the July 18, 2013 Electric Utility Commission meeting	July 18, 2011
20110808 DPA Report	August 2011 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Aug. 8, 2011
20110815 EUC Minutes	Minutes of the August 15, 2013 Electric Utility Commission meeting	Aug. 15, 2011

20111010 DPA Report	September 2011 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Oct. 10, 2011
20111108 DPA Report	October 2011 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Nov. 8, 2011
20120813 DPA Report	July 2012 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Aug. 13, 2012
20120912 DPA Report	August 2012 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Sept. 12, 2012
20121011 DPA Report	September 2012 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Oct. 11, 2012
20121214 DPA Report	November 2012 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Dec. 14, 2013
20130118 DPA Report	December 2012 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Jan. 18, 2013
20130218 DPA Report	January 2013 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Feb. 18, 2013
20130318 Memo to EUC	Memo to Electric Utility Commission members regarding utility customer connection and disconnection update	March 18, 2013
20130318 EUC Minutes	Minutes of the March 18, 2013 Electric Utility Commission meeting	March 18, 2013
20130318 DPA Report	February 2013 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	March 18, 2013

20130415 Memo to EUC	Memo to Electric Utility Commission members responding to questions regarding the disconnection process	April 15, 2013
20130417 DPA Report	March 2013 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	April 17, 2013
20130524 DPA Report	April 2013 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	May 24, 2013
20130614 DPA Report	May 2013 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	June 14, 2013
20130715 EUC Minutes	Minutes of the July 15, 2013 Electric Utility Commission meeting	July 15, 2013
20130903 CCAE Presentation	Briefing and discussion of the collections process, utility service disconnections, and reconnection fees and policies.	Sept. 3, 2013
20130926 Resolution No. 20130926-083	Approve a resolution directing the City Manager to limit any utility service cut-off for nonpayment to electric service only.	Sept. 26, 2013
20131007 DPA Report	September 2013 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Oct. 7, 2013
20131107 Resolution No. 20131107-052	Approve a resolution directing the City Manager to work with the Discount Steering Committee and other consumer advocates to develop rules for deferred payment agreements and service disconnections and to offer recommendations on an arrearage management plan and education related to utility usage reduction, and to report back to the City Council within six months.	Nov. 7, 2013

20131118 DPA Report	October 2013 report to the Electric Utility Commission reporting the number of deferred payment agreements and disconnections.	Nov. 18, 2013
20131121 Memo to Council	Memo to Mayor and Council from Austin Energy, Austin Water Regarding Options to Curtail Disconnection of Residential Water Service (Resolution 20130926-083)	Nov. 21, 2013
20131205 Council Presentation	Briefing and discussion of Austin Energy's process for disconnection and reconnection of residential utility services, including payment arrangements and coordination with financial assistance agencies.	Dec. 5, 2013
20131205 Council Ordinance No. 20131205-007	Approve an ordinance amending City Code Chapter 15-9 relating to deferred payment agreements and restoration of utility service.	Dec. 5, 2013
20140529 CCAE Presentation	Briefing and discussion regarding the City's process for disconnection and reconnection of utility services.	May 29, 2014
20140623 CCAE Presentation	Briefing and discussion regarding utility customer debt.	June 23, 2014
20140818 EUC Presentation	Briefing on Payment Arrangements, Arrearage Management and Hearings Process	Aug. 18, 2014
20140818 EUC Minutes	Minutes of the Aug. 18, 2014 Electric Utility Commission meeting	Aug. 18, 2014
20141113 CCAE Presentation	Briefing and discussion regarding unpaid and overdue customer debts, deferred payment arrangements, and the administrative hearings process	Nov. 13, 2014
20141117 EUC, RMC Presentation	Briefing and possible action regarding City of Austin utilities' customer deferred payment agreements, arrearage management program and hearings process	Nov. 17, 2014
20141117 EUC Minutes	Minutes of the Nov. 17, 2014 Electric Utility Commission meeting	Nov. 17, 2014
20150326 AEUOC Presentation	Briefing and discussion regarding a financial overview of Austin Energy including: commercial paper and refunding bonds; cash and reserves policy; payment arrangements, arrearage management and bad debt;	March 26, 2015

	Customer Assistance Program enrollment; and large demand customer contracts.	
20150528 AEUOC Presentation	Briefing and discussion regarding payment arrangements, arrearage management and bad debt.	May 28, 2015
20150623 RCA	Request for Council Action regarding amendment to City Code pertaining to utility deferred payment agreements.	June 23, 2015
20150623 Council Ordinance No. 20150623-001	Ordinance amending City Code Chapter 15-9 regarding utility deferred payment agreements.	June 23, 2015

Prepared by: JV, HM
Sponsored by: Mark Dreyfus

AELIC 10-13 Please provide a copy of each document identified in No. 10-12.

ANSWER:

Please see Attachment 1.

Prepared by: JV, HM
Sponsored by: Mark Dreyfus

Utility Customer Debt

Council Committee on Austin Energy

June 23, 2014

Forecast – Bad Debt Expense

	FY2013 Adjusted	FY2014 CYE	FY2015 Forecast*	FY2016 Forecast*	FY2017 Forecast*	FY2018 Forecast*	FY2019 Forecast*
Electric	$17,178,827	$17,178,827	$14,441,455	$11,704,083	$8,966,712	$6,229,340	$3,491,968
Water	$1,655,064	$1,655,064	$1,555,049	$1,455,034	$1,355,020	$1,255,005	$1,154,990
Wastewater	$1,336,139	$1,336,139	$1,295,644	$1,255,148	$1,214,653	$1,174,157	$1,133,662
ARR	$1,829,871	$1,829,871	$1,631,301	$1,432,731	$1,234,160	$1,035,590	$837,020
Drainage	$1,337,374	$1,337,374	$1,256,673	$1,175,972	$1,095,270	$1,014,569	$933,868
Transportation	$915,292	$915,292	$915,292	$915,292	$915,292	$915,292	$915,292
Total	**$24,252,567**	**$24,252,567**	**$21,095,414**	**$17,938,260**	**$14,781,107**	**$11,623,953**	**$8,466,800**

***Future year forecasts are not adjusted for potential rate increases or growth**

Overview

- Key Understandings

Standard Collections Process (Active)

- How Did We Get Here?
  - Extended Weather Moratoriums
  - System Conversion
  - Collection Activity Moratorium Associated With System Conversion
- Current Challenges
- What Are We Doing About It?
  - Collections Efficiencies Gained
  - Collections Forecasts
  - Collections Expectations

Key Understandings

- **Bad Debt Expense**
  An accounting estimation of uncollectible Accounts Receivable (unpaid utility bills) reflected in each department's fund summary as an operating requirement.

- **Budget Forecast Process:**
  - Utility-related Bad Debt Expense is trued up on an annual basis
  - Bad Debt Expense forecast through FY19 has been provided to City Departments
  - Larger than normal adjustment because of increased A/R balances, change to allowance calculation methodology, and reporting issues
  - Consultants are currently on board to improve aging reporting (mid-April through July)

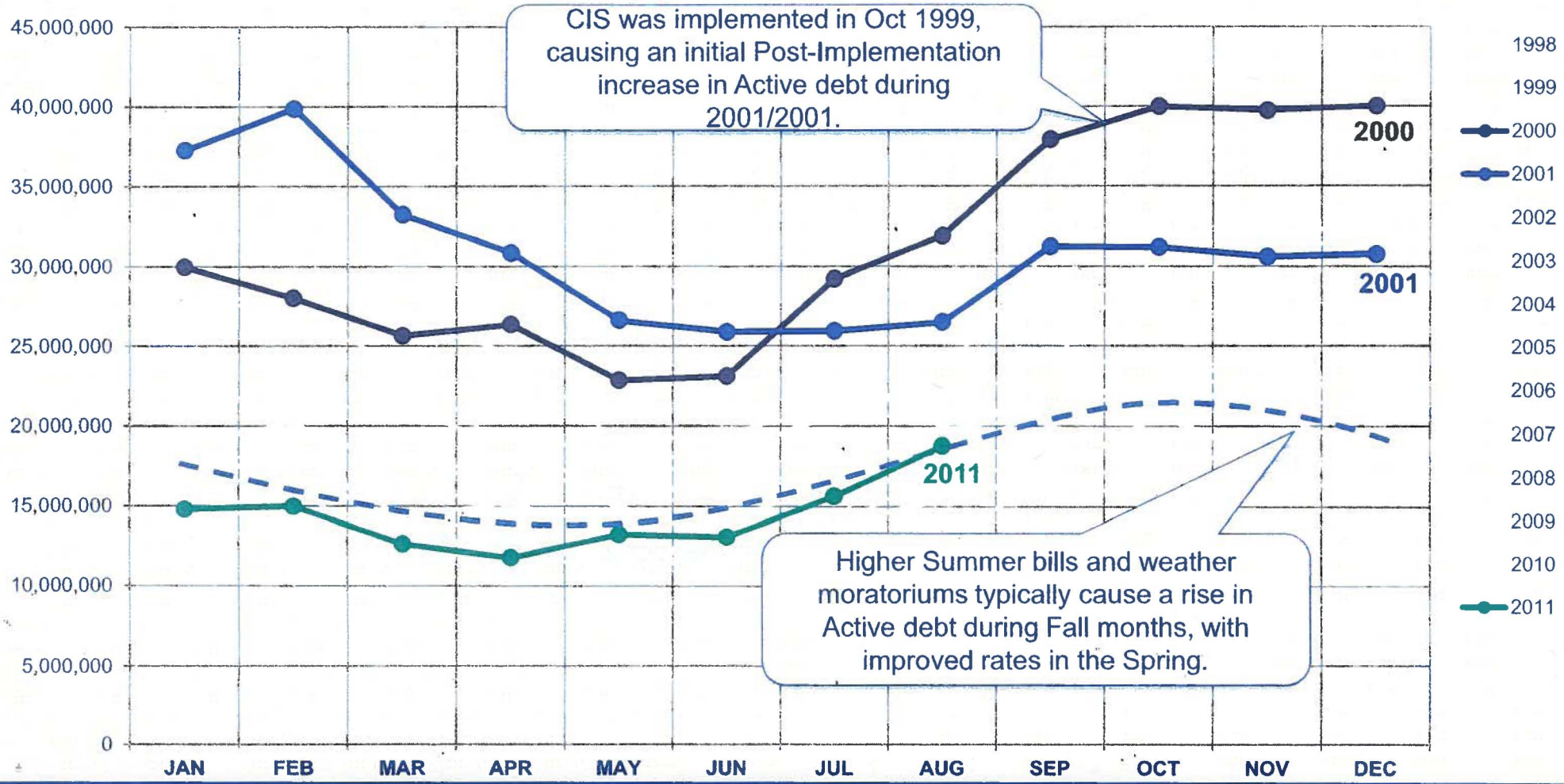
What Are We Doing About It?

- Standard collections processes are fully implemented and highly automated
- Full collections implementation has resulted in increased payment response to collection activities
- System consultants on-site to improve aging reporting
  - Aged debt reporting segregated by type
  - Additional financial reports for collections forecasting
- Established 4 levels of outside collection efforts with 5 vendors for 'inactive' utility accounts
- Additional resources focusing on older debt collection processes
- On-site management review of collection agency vendors for quality assurance purposes

Historical Trends

Total Active A/R Over 30 Days 1998 - 2011

AE predicts future improved annual collection recovery rates for Active debt based on previous Post - CIS implementation trend upturn.



Schedule H-5.3

Component Breakdown Fixed and Variable Under Proposed Base Rates and Estimated FY 2017 Pass-Throughs

No.	Customer Class	Reference	Customer	Delivery	Demand	Energy	CAP	SAL	EES	Regulatory	Supplemental Regulatory	Green Choice	Other Power Supply	Total	Fixed	%	Variable	%
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
1	Inside City of Austin																	
2	Residential	WP H-5.1	$ 35,435,040	$ -	$ -	$ 161,253,341	$ 5,043,625	$ 4,683,239	$ 7,959,767	$ 37,554,860	$ -	$ 1,689,255	$ 100,517,609	$ 354,136,736	$ 35,435,040	12.3%	$ 318,701,696	44.0%
3	Secondary Voltage (< 10 kW)	WP H-5.2	5,234,414	-	-	11,408,362	143,734	319,650	543,285	2,563,267	-	559,439	6,610,848	27,383,000	5,234,414	1.8%	22,148,585	3.1%
4	Secondary Voltage (≥ 10 < 300 kW)	WP H-5.3	4,957,062	27,827,440	40,036,240	56,684,971	1,529,953	3,402,453	5,782,906	22,686,783	-	1,799,431	72,800,227	237,507,465	95,507,525	33.2%	141,999,940	19.6%
5	Secondary Voltage (≥ 300 kW)	WP H-5.4	850,278	21,243,866	37,750,574	45,187,835	1,461,001	3,249,110	5,522,280	15,501,604	-	6,401,385	71,441,170	208,609,101	75,346,321	26.2%	133,262,780	18.4%
6	Primary Voltage (< 3 MW)	WP H-5.5	270,600	3,339,002	9,221,493	2,903,928	285,292	619,954	1,053,692	3,018,115	-	6,560,679	11,873,138	39,145,895	15,849,210	5.5%	23,296,684	3.2%
7	Primary Voltage (≥ 3 < 20 MW)	WP H-5.6	422,400	3,516,549	10,760,703	3,027,150	337,923	734,323	1,248,076	2,781,274	-	3,312,857	17,258,875	43,400,129	17,480,926	6.1%	25,919,203	3.6%
8	Primary Voltage (≥ 20 MW)	WP H-5.7																
9	Primary Voltage (≥ 20 MW @ 85% aLF)	WP H-5.8																
10	Transmission Voltage	WP H-5.9																
11	Transmission Voltage (≥ 20 MW @ 85% aLF)	WP H-5.10																
12	Street Lighting and Traffic Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
13	City-Owned Outdoor Lighting	WP H-5.12	2,327,547	-	-	-	-	-	-	-	-	-	387,738	2,715,285	2,327,547	0.8%	387,738	0.1%
14	Customer-Owned, Non-Metered	WP H-5.13																
15	Customer-Owned, Metered	WP H-5.14	10,548	-	-	168,399	-	-	-	-	-	-	87,846	266,793	10,548	0.0%	256,245	0.0%
16	Subtotal-Inside City of Austin		$ 49,893,329	$ 64,525,153	$ 122,050,164	$ 284,882,685	$ 9,800,810	$ 14,857,921	$ 25,252,947	$ 91,498,294	$ -	$ 21,862,046	$ 327,194,264	$ 1,011,817,613	$ 287,848,813	28.4%	$ 723,968,800	71.6%
17																		
18	Outside City of Austin																	
19	Residential	WP H-5.1	$ 5,761,320	$ -	$ -	$ 56,074,429	$ 1,031,851	$ -	$ 2,274,142	$ 10,729,596	$ -	$ 282,136	$ 28,843,046	$ 104,996,519	$ 5,761,320	17.8%	$ 99,235,199	72.8%
20	Secondary Voltage (< 10 kW)	WP H-5.2	834,149	-	-	1,683,367	21,169	-	80,016	377,523	-	17,396	1,010,694	4,024,315	834,149	2.6%	3,190,166	2.3%
21	Secondary Voltage (≥ 10 < 300 kW)	WP H-5.3	783,684	4,204,386	6,043,805	7,489,021	208,299	-	787,328	3,442,576	-	287,027	9,883,305	33,129,431	14,474,451	44.8%	18,654,980	13.7%
22	Secondary Voltage (≥ 300 kW)	WP H-5.4	95,410	2,293,998	3,695,886	3,830,289	135,928	-	513,781	1,759,989	-	185,014	6,450,720	18,961,016	7,845,283	24.3%	11,115,733	8.2%
23	Primary Voltage (< 3 MW)	WP H-5.5	39,600	428,628	1,040,954	190,694	25,452	-	94,004	387,436	-	139,061	1,124,446	3,470,274	1,896,618	5.9%	1,573,656	1.2%
24	Primary Voltage (≥ 3 < 20 MW)	WP H-5.6																
25	Primary Voltage (≥ 20 MW)	WP H-5.7																
26	Primary Voltage (≥ 20 MW @ 85% aLF)	WP H-5.8																
27	Transmission Voltage	WP H-5.9																
28	Transmission Voltage (≥ 20 MW @ 85% aLF)	WP H-5.10																
29	Street Lighting and Traffic Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
30	City-Owned Outdoor Lighting	WP H-5.12	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
31	Customer-Owned, Non-Metered	WP H-5.13																
32	Customer-Owned, Metered	WP H-5.14	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0%	-	0.0%
33	Subtotal-Outside City of Austin		$ 7,573,562	$ 7,200,635	$ 11,688,191	$ 69,532,338	$ 1,466,643	$ -	$ 3,911,007	$ 16,980,613	$ -	$ 910,633	$ 49,374,665	$ 168,638,287	$ 32,335,882	19.2%	$ 136,302,404	80.8%
34																		
35	Total Revenues		$ 57,466,892	$ 71,725,787	$ 133,738,355	$ 354,415,023	$ 11,267,452	$ 14,857,921	$ 29,163,954	$ 108,478,907	$ -	$ 22,772,679	$ 376,568,929	$ 1,180,455,900	$ 320,184,695	27.1%	$ 860,271,205	72.9%
36			4.9%	6.1%	11.3%	30.0%	1.0%	1.3%	2.5%	9.2%	0.0%	1.9%	31.9%	100.0%				