

**AUSTIN ENERGY TARIFF PACKAGE  
UPDATE—2016 RATE REVIEW**

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**BEFORE THE  
CITY OF AUSTIN IMPARTIAL  
HEARINGS EXAMINER**

AUSTIN ENERGY

2016 MAY 18 PM 2:07

**DIRECT TESTIMONY  
OF  
CLARENCE L. JOHNSON**

**ON BEHALF OF THE  
INDEPENDENT CONSUMER ADVOCATE**

**MAY 3, 2016**

**(Corrected – May 18, 2016)**

**CITY OF AUSTIN 2016 BASE RATE REVIEW  
BEFORE THE IMPARTIAL HEARING EXAMINER**

**DIRECT TESTIMONY OF CLARENCE JOHNSON**

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1                                   **I.     STATEMENT OF QUALIFICATIONS**

2   **Q.     PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3   A.     My name is Clarence Johnson. My address is 3707 Robinson Avenue, Austin, Texas  
4           78722.

5   **Q.     WHAT IS YOUR OCCUPATION?**

6   A.     I am self-employed as a consultant who provides technical analysis and advice regarding  
7           energy and utility regulatory issues. My testimony sets out the position and  
8           recommendations of the Independent Consumer Advocate (ICA).

9   **Q.     PLEASE EXPLAIN THE ROLE OF THE ICA.**

10  A.     The City of Austin retained John B. Coffman LLC as the Independent Consumer  
11          Advocate, with the role of representing the interests of residential, small commercial, and  
12          houses of worship customers in the electric rate review process. Mr. Coffman's ICA  
13          team includes myself and Ms. Janee Briesmeister as subcontractors.

14  **Q.     DO YOU HAVE PREVIOUS EXPERIENCE AS AN EXPERT ON REGULATED**  
15          **UTILITY MATTERS IN TEXAS?**

16  A.     Yes. I have approximately 33 years of experience as a professional regulatory analyst for  
17          Texas Office of Public Utility Counsel (OPUC) and as an independent expert witness in  
18          proceedings before the Public Utility Commission of Texas (PUC or Commission),  
19          Pennsylvania Public Utility Commission, and Connecticut Department of Public Utilities.

20  **Q.     WHAT WERE YOUR RESPONSIBILITIES AT OPUC?**

21  A.     As OPUC's Director of Regulatory Analysis, I was the professional staff person with the  
22          primary responsibility for advising the OPUC on economic and regulatory policy issues.

1 My responsibilities included reviewing utility rate applications, recommending actions or  
2 positions to be taken by the Office, preparing and presenting expert testimony, and  
3 working with other experts employed or retained by OPUC to coordinate the agency's  
4 technical evidentiary positions. I also held supervisory responsibilities with respect to  
5 OPUC's technical analysis staff. In addition, my responsibilities included providing  
6 technical assistance on legislative matters.

7 **Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**  
8 **PROFESSIONAL EXPERIENCE.**

9 A. I have a B.S. in Political Science and a M.A. in Urban Studies from the University of  
10 Houston. My graduate degree is in an interdisciplinary program offered by the  
11 University of Houston's College of Social Science which incorporated substantial  
12 training in economics, including course work in the application of cost-benefit analysis to  
13 public policy. During my 25-year tenure at OPUC, I gained experience in virtually all  
14 phases of economic review required for the ratemaking process. I was chairman of the  
15 Economics and Finance Committee of the National Association of State Utility  
16 Consumer Advocates (NASUCA) and served as a presenter for NASUCA's workshops  
17 and panels on cost allocation and rate design, Demand-Side Management (DSM)  
18 incentives, market power and electric utility competition. Also, at various times, I have  
19 undergone training in specific subjects such as electric wholesale market design,  
20 cogeneration engineering and Electric Reliability Council of Texas (ERCOT) operations.  
21 During my work over the last six years as a consultant, I have prepared reports,  
22 comments, and testimony related to electricity issues for public interest, state agency, and

1 local government organizations. I have testified as an expert witness in over 100 utility  
2 rate proceedings. A summary of my educational and professional background is attached  
3 as Attachment A.

4 **Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY?**

5 A. My testimony will address selected issues with respect to Austin Energy's ("AE" or  
6 "Company") proposed base rate change. My recommendations focus on the class cost of  
7 service study (CCOS), the implications of the CCOS results for customer class revenues,  
8 certain aspects of AE's proposed revenue requirement, class rate design, and potential  
9 impacts on future rates, as well as addressing certain AE policies and programs. This  
10 testimony does not limit the positions that the ICA may take in this proceeding before the  
11 Impartial Hearings Examiner ("IHE"). The ICA reserves the right to review other  
12 parties' positions, as well as evidence adduced in the proceeding, in order to supplement  
13 the ICA's recommendations during briefing.

14 **II. OVERVIEW AND SUMMARY**

15 **Q. HOW DID THE ICA APPROACH THIS PROPOSAL TO CHANGE ELECTRIC**  
16 **RATES?**

17 A. In pursuit of its mission, the ICA independently reviewed and analyzed Austin Energy's  
18 entire proposal by on behalf of the best interests of a majority of residential, small  
19 commercial, and Houses of Worship customers. The ICA was guided by general rate-  
20 making principles set out in Austin Energy's 2011 rate philosophy white paper,  
21 particularly with regard to the stated goals of maintaining affordability for all ratepayers

1 and ensuring that the electric rates are fair among the various customer classes.<sup>1</sup> The ICA  
2 was also guided by the affordability goals adopted by the Austin City Council in  
3 February 2014, stating that Austin Energy should strive for (1) overall rates that rise no  
4 more than 2 percent annually, and (2) that AE's rates remain in the lower 50 percent of  
5 rates in the State.<sup>2</sup>

6 **Q. WHAT IS AE'S PROPOSAL FOR CHANGING THE OVERALL REVENUE**  
7 **REQUIREMENT AND RATE DESIGN AS A RESULT OF THIS PROCEEDING?**

8 A. The base rate revenue requirement is \$614.4 million, which does not include the  
9 projected costs for the pass-through charges (Power Supply Adjustment, Regulatory  
10 Charge, and Community Benefits Charge). AE states that its current rate structure would  
11 collect \$17.5 million more than the revenue required to meet test year 2014 costs, which  
12 represents excess revenue to be returned to customers through reduced rates.<sup>3</sup> Austin  
13 Energy proposes that none of this excess revenue be applied to decrease the electric rates  
14 of residential and small commercial customer classes, and rather recommends that any  
15 decrease be applied to its larger commercial customers, which it claims are paying above  
16 the cost to serve those customers. Austin Energy also proposes to modify the five rate  
17 tiers for residential customers by raising the bottom tier rate and reducing the rate of the  
18 top tier.<sup>4</sup>

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<sup>1</sup> Tariff Package, p. 037; Appendix B.

<sup>2</sup> Tariff Package, Appendix F, p. 374.

<sup>3</sup> Tariff Package, p. 021; Footnote 11.

<sup>4</sup> Tariff Package, p. 025.

1   **Q.    HOW DO THE ICA’S OVERALL RECOMMENDATIONS DIFFER?**

2    A.    The ICA’s review and analysis supports an overall revenue requirement reduction of  
3       \$39.8 million, more than twice the level of reduction proposed by Austin Energy, as  
4       explained in Section III of this testimony. The ICA’s class cost of service study also  
5       produced different results than the utility’s study regarding the relative cost positions of  
6       classes, showing that the current base revenues for residential and small commercial  
7       customer classes are at or above those classes’ cost of service. Therefore, the ICA is  
8       recommending that a greater number of customers should be sharing in the overall  
9       revenue requirement reduction, including a significant electric base rate reduction for  
10      residential consumers, as explained in Section IV of this testimony.

11   **Q.    PLEASE SUMMARIZE THE ICA’S SPECIFIC FINDINGS AND CONCLUSIONS**  
12   **AS SET OUT IN THIS TESTIMONY.**

13       Based upon its analysis and review, the ICA recommends the following findings and  
14      conclusions, which are explained herein in greater detail:

- 15      1. AE’s proposed Revenue Requirement should be reduced further through several  
16         reasonable and necessary adjustments.
- 17           a. AE’s Uncollectible Expense Allowance should be normalized to reduce the effect  
18             of the ballooning bad debt in 2013 and 2014 as a result of utility billing issues and  
19             which should thus be non-recurring, reducing this allowance by \$5.855 million.
- 20           b. The Non-Nuclear Decommissioning expense should be reduced by 48%, a \$9.89  
21             million revenue requirement reduction.
- 22           c. With regard to Outside City Rate Discounts, the ICA recommends that for cost of  
23             service purposes, customers inside the city should be “held harmless”.  
24  
25  
26  
27



- 1 d. The Power Supply Stabilization Reserve should be funded at 90 days of net power  
2 supply costs and should not be funded with net PSA balances; credits should  
3 continue to flow to customers in the PSA calculation.  
4
- 5 e. The level of the General Transfer Fund is a decision for the Austin City Council  
6 to make on a separate track during the city's budget review process. This  
7 decision should be made with the utmost transparency, sufficient public input, and  
8 a proper balancing of public interests.  
9
- 10 f. Economic Development and Community Programs should be treated as part of  
11 the General Fund Transfer.
- 12 2. A greater number of customers should benefit from and share in the overall revenue  
13 requirement reduction through lower electric base rates. ICA's proposal to reduce the  
14 residential base rates is supported by recommended changes to the class cost of  
15 service study.  
16
- 17 a. The Base-Intermediate-Peak Method (BIP), as revised by ICA, should be adopted  
18 for the purpose of allocating production plant among customer classes.  
19
- 20 b. The ICA also recommends that changes be made to the following components of  
21 the utility's class cost of service study: Production Non-Fuel O&M Expense  
22 Classification, Functionalization/Classification of A& G Account 920 (Salaries),  
23 Classification and Allocation of Transformer/Substation Investment, Allocation of  
24 Customer Service, Allocation of Meters and Services, Allocation of Customer  
25 Accounts, and Allocation of Service Initiation Revenue.  
26
- 27 c. When these proper changes are made to the class cost of service study, it casts  
28 considerable doubt on AE's claim that a subsidy to the residential and small  
29 commercial class is embedded in current rates.  
30
- 31 d. ICA contends that the revenue requirement decrease should be distributed broadly  
32 among the customer classes, rather than precisely linked to specific CCOS results.  
33 The base revenues for the customer classes which are far below cost—the lighting  
34 classes—should remain unchanged. The Transmission >20 MW, 85% LF class  
35 revenues should be set at cost, ensuring that other customers are not subsidizing  
36 its contract rate. Incorporating an approximate \$2 million base revenue increase  
37 for that class produces a \$41 million revenue decrease to be distributed among the  
38 remaining classes. This revenue decrease should be allocated on the basis of class  
39 shares of kWh consumption.  
40
- 41 e. ICA agrees with AE that the current residential customer charge should remain  
42 unchanged at \$10.00. ICA disagrees with AE's cost assessment for the customer  
43 charge, and opposes movement of the charge in the direction of that target.

- 1
- 2 f. The basic rate level for the lowest tier of usage for residential customers should
- 3 also not be increased. After using part of the base revenue reduction for the
- 4 purpose of reducing the steepness of the tier structure, any remaining residential
- 5 base revenue reduction amount should be used to reduce all tiers equally. The
- 6 utility should also study potential reduction in the number of tiers for residential
- 7 customers inside the city.
- 8
- 9 g. The ICA does not object to AE's proposed change in its summer/winter seasonal
- 10 base rate differential.
- 11
- 12 h. The ICA does not generally object to the rate design changes proposed for the
- 13 small commercial customer classes [Sec. <10 kW (S1) and the lower end of the
- 14 Sec. 10 – 300 kW (S2) classes]. The ICA opposes increasing the small
- 15 commercial customer charges.
- 16
- 17 i. With regard to the proposal to eliminate the Houses of Worship (HOW) discount,
- 18 the ICA is concerned about dramatic rate shock among HOWs, which should be
- 19 avoided. ICA disagrees with moving the HOWs off the transition discount, given
- 20 Austin Energy's plans to perform rate studies that might result in a more
- 21 appropriate rate treatment for HOW.
- 22
- 23 j. ICA proposes that the transition for HOWs be extended—retain the cap of 13.015
- 24 cents per kWh and the practice of measuring peak usage during weekdays.
- 25 Preferably, AE should absorb the discount, instead of re-allocating the cost to
- 26 other customers. The transition should not end until after the planned studies
- 27 have been completed and the next rate case is completed. AE should conduct
- 28 further outreach to the HOWs during the study periods.
- 29
- 30 3. The ICA makes certain recommendations regarding AE policies and programs.
- 31
- 32 a. Austin Energy should develop a plan to improve its customer satisfaction
- 33 ratings, working with the Electric Utility Commission, ratepayer advocates
- 34 and the public in developing, executing and monitoring the plan for improved
- 35 customer satisfaction.
- 36
- 37 b. Proposed pilot programs should be reviewed by the Electric Utility
- 38 Commission and the Council, separate and apart from the budget process.
- 39 Where a pilot has identified stakeholders, such as low income advocates,
- 40 Austin Energy should consult these groups about pilot goals and design, prior
- 41 to initiating that pilot. Pilots should be given a firm end date; no pilot should
- 42 go on indefinitely or for more than two years without a comprehensive
- 43 review. Austin Energy should fully develop the terms and conditions of the

1 pilot, its goals, customer education, performance criteria, potential cross  
2 subsidies, and evaluation metrics prior to initiating a pilot.

- 3
- 4 c. With regard to the current Prepayment Pilot Program, the ICA recommends  
5 that it not be allowed to bypass consumer protections nor should it be targeted  
6 to low income customers. The ICA recommends that Austin Energy develop  
7 a collaborative of stakeholder groups, including low income advocates, to  
8 review and make recommendations on the prepayment pilot, including  
9 adoption of consumer protections equivalent to current consumer protections.
- 10
- 11 d. Austin Energy should be required to implement a “Pick Your Own Due Date”  
12 option for consumers as soon as it is technically feasible to do so, and then  
13 publicly promote this billing accommodation to its consumers.
- 14
- 15 e. Austin Energy’s cost of service should be examined more frequently than  
16 every five years. Allowing for a thorough and transparent analysis of Austin  
17 Energy’s cost of service every 2-3 years, if possible, is a good policy, and is  
18 much preferable to allowing rates to change over time without such a full  
19 review.
- 20
- 21 f. There should be no piecemeal changes to electric rates or rate design, outside  
22 of the already established PSA and other pass-through charges, during the  
23 time period in between this rate review and the next rate review proceeding.
- 24
- 25 g. The studies identified by AE should be completed prior to the next rate  
26 review. AE should engage the Electric Utility Commission and stakeholder  
27 groups during the study process, and AE should provide technical expertise to  
28 the EUC and stakeholder groups during these studies.
- 29

### 30 **III. REVENUE REQUIREMENT ADJUSTMENTS**

#### 31 **Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

32 A. I will discuss selected issues pertaining to the amount of revenues required to recover  
33 AE’s reasonable and necessary cost of service. This section on revenue requirement  
34 covers how much total rate revenue is needed, while the subsequent section, on class cost  
35 of service and rate design, will cover how to divide up the total revenue requirement  
36 among customer classes.

1       **A.     Uncollectible Expense Allowance (Account 904)**

2       **Q.     HOW MUCH DOES AUSTIN ENERGY INCLUDE FOR UNCOLLECTIBLE**  
3       **EXPENSE?**

4       A.     AE's 2014 uncollectible expense in Account 904 was \$20.86 million. The cost of service  
5       adjusts this amount to a test year level of \$16.1 million.<sup>5</sup> Uncollectible expense reflects  
6       bad debt cost.

7       **Q.     DO YOU AGREE WITH THIS UNCOLLECTIBLE ALLOWANCE?**

8       A.     No. This amount of uncollectible expense is high by almost any standard. The  
9       allowance for uncollectible expense should represent a prospective level sufficient to  
10      recover a reasonable recurring amount of bad debt during the period that these tariffs are  
11      in effect.

12      **Q.     HOW DO YOU EVALUATE THE REASONABLE LEVEL OF BAD DEBT**  
13      **EXPENSE?**

14      A.     On an annual basis, the amount of bad debt expense can fluctuate based on factors such  
15      as economic conditions, the size of customer bills, and the utility's management and  
16      execution of billing and collection activities. In order to develop a recurring allowance  
17      for bad debt for a utility like Austin Energy, my recommendation is to normalize the  
18      uncollectible amount based upon historic uncollectible experience. This minimizes any  
19      distortions associated with non-recurring events and unusual conditions. Because the  
20      amount of uncollectible expense is related to the amount of annual revenues, my  
21      approach expresses the uncollectible amount as a ratio of AE's electric revenues.

---

<sup>5</sup> WP-D-1.2.9.

1 **Q. WHAT IS YOUR ANALYSIS OF AE'S HISTORIC UNCOLLECTIBLE**  
2 **EXPERIENCE?**

3 A. The annual uncollectible expense over an eight year period is shown below. The 2015  
4 data is unaudited and, therefore, is included only for comparison purposes. The analysis  
5 shows an average rate over five years and seven years.

	(000's)		
	Uncollectibles	Revenues	Uncollectible Rate
2015	\$8,463		
2014	\$20,863	1,234,701	1.6897%
2013	\$17,257	1,183,865	1.4577%
2012	\$3,483	1,081,609	0.3220%
2011	\$3,546	1,122,609	0.3159%
2010	\$4,166	1,030,130	0.4044%
2009	\$3,649	1,032,397	0.3534%
2008	\$2,093	1,069,822	0.1956%
Avg Rate (7 yr)			0.6770%
Avg Rate (5 yr)			0.8379%

6  
7 **Q. USING THIS HISTORICAL EXPERIENCE, DID YOU DEVELOP A**  
8 **NORMALIZED AMOUNT FOR UNCOLLECTIBLE EXPENSE?**

9 A. Yes. The historical uncollectible rate was relatively stable until 2013 and 2014, when the  
10 uncollectible amount more than quintupled. A range for the annual allowance can be  
11 calculated based on the average uncollectible rates for the seven year and five year  
12 periods. The shorter five year period produces the larger amount, because the 2013 and

1 2014 uncollectible amounts comprise a greater proportion of the average. The range is  
2 \$8.2 million - \$10.4 million, compared to the \$16.1 million requested by AE. Notably,  
3 the \$8.4 million uncollectible amount for 2015 falls within this range.

4 **Q. IS IT LIKELY THAT THE MASSIVE UNCOLLECTIBLE INCREASE IN 2013**  
5 **AND 2014 IS DUE TO EXTRAORDINARY OR UNUSUAL EVENTS?**

6 A. Yes. An increase of more than five-fold for a historically stable expense generally is  
7 associated with extraordinary events. And, in this case, Austin Energy incurred  
8 widespread problems in the implementation of a new IBM billing system in the 2011 –  
9 2013 timeframe. Austin Energy documented numerous complaints about the vendor’s  
10 inadequacies, and the billing issues garnered national attention.<sup>6</sup> More than 100,000  
11 customers were affected by billing system errors in 2011 - 2012.<sup>7</sup> The errors included  
12 both under- and over-billings, as well as substantial numbers of customers who did not  
13 receive bills. Between October 2011 and January 2013, Austin Energy ceased collection  
14 activity because of uncertainty about the accuracy of bills.<sup>8</sup> As a result, substantial debt  
15 accumulated, with many customers accruing thousands of dollars of past due bills.  
16 Because the lack of bills and bill errors contributed to the amounts owed by customers,  
17 the City Council liberalized the deferred payment procedures. Although the billing

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<sup>6</sup> *Information Week*, Feb. 23, 2012, Chronology of An Outsourcing Disaster, [http://www.informationweek.com/it-strategy/chronology-of-an-outsourcing-disaster/d/d-id/1102987?page\\_number=1](http://www.informationweek.com/it-strategy/chronology-of-an-outsourcing-disaster/d/d-id/1102987?page_number=1)

<sup>7</sup> *Austin American Statesman*, Feb 18, 2012, More 100,000 Austin Energy Customers Hit By Billing Errors From \$55 Million IBM System, <http://www.statesman.com/news/news/special-reports/more-than-100000-austin-energy-customers-hit-by-bi/nRkb5/>

<sup>8</sup> *Austin American Statesman*, Feb. 7, 2015, Why Customers Unpaid Bills Are Piling Up At Austin Energy, <http://www.mystatesman.com/news/news/local/why-customers-unpaid-bills-are-piling-up-at-austin/nj6jM/>

1 system problems may have occurred in 2011-2013, given the potential length of deferred  
2 payment plans (up to 36 months) and the customer's ability to enter into multiple  
3 deferred payment plans, the effect of the billing system issues may have continued to  
4 affect uncollectible amounts well into 2014. This effect should diminish as the time  
5 interval lengthens since the billing problems occurred. The ballooning bad debt expense  
6 in 2013 and 2014 should not be treated as a recurring event. Therefore, normalizing the  
7 expense amount based on average historical experience is appropriate.

8 **Q. YOU MENTIONED THAT AUSTIN ENERGY'S REQUESTED**  
9 **UNCOLLECTIBLE ALLOWANCE IS HIGH BY ANY STANDARD. DO YOU**  
10 **HAVE ANY EVIDENCE TO SUPPORT THAT STATEMENT?**

11 A. Yes. The table below compares Austin Energy's requested uncollectible expense to the  
12 uncollectible cost requested in the most recent rate case of three investor-owned bundled  
13 utilities in Texas. In order to adjust for the relative size of the utilities, the uncollectible  
14 amount is expressed on a per customer basis. Austin Energy's requested uncollectible  
15 expense per customer is more than three times the other utilities' uncollectible request.  
16 The three bundled investor-owned utilities are Southwestern Public Service Co. (SPS),  
17 Entergy Texas Inc. (ETI), and El Paso Electric Co. (EPE).

		customers	per customer
EPE Uncollectible	1,923,398	306,046	\$ 6.28
SPS Uncollectible	2,661,033	251,659	\$ 10.57
ETI Uncollectible	4,887,120	578,693	\$ 8.45
AE Uncollectible*	16,054,751	436,499	\$ 36.78

\* test year  
adjusted

**Q. WHAT IS THE ADJUSTMENT THAT YOU RECOMMEND?**

A. I recommend using the upper end of the range for normalized uncollectible expense. This amount is \$10,199,660. After known and measurable adjustment, Austin Energy utilized a test year amount of \$16,054,751. Therefore, my proposed expense reduction is \$5.855 million.

**Q. IS YOUR RECOMMENDATION CONSISTENT WITH COST OF SERVICE RATE MAKING?**

A. Yes. The test year concept is intended to be representative of future costs. Given the large fluctuation in uncollectible expense caused by unusual circumstances, normalizing the expense level to reflect longer term experience is reasonable. The portion of test year costs which is unrepresentative of prospective costs should have been recovered from revenues collected at the time the expense was incurred; such costs are not appropriately



1 recovered with future revenues. This principle is inherent in historical test year rate  
2 making.<sup>9</sup>

3 **Q. IS YOUR RECOMMENDATION SUPPORTED BY REASONABLENESS**  
4 **CONSIDERATIONS?**

5 A. Yes. Even with my proposed reduction in the allowance for uncollectibles, the adjusted  
6 amount remains quite high. With the disallowance, the uncollectible expense per  
7 customer is \$23.35—more than twice the uncollectible per customer cost of SPS, the  
8 highest cost investor-owned utility in the table presented above. Regardless of the  
9 potential impact of previous billing system errors, Austin Energy’s management is  
10 responsible for taking action to reduce the level of uncollectible expense. Given the high  
11 amount of uncollectible expense, I anticipate that Austin Energy will attempt to manage  
12 the expense to a more reasonable level.

13 **B. Non-Nuclear Decommissioning**

14 **Q. WHAT IS NON-NUCLEAR DECOMMISSIONING COST?**

15 A. This is the cost of decommissioning a fossil fuel generating plant at its retirement.  
16 Decommissioning cost includes both costs (such as demolition and removal of structures)  
17 and credits (sometimes called “salvage value”) for recycling and selling components. For  
18 most regulated electric utilities, the depreciation rate calculation is set to explicitly  
19 recover the net of demolition/removal and salvage, which is called net salvage. In this  
20 fashion, the depreciation rates cover the cost of decommissioning over the life of the

---

<sup>9</sup> *Application of Gulf States Utilities Company for Authority to Change Rates*, Docket No. 3871, 7 P.U.C. BULL. 410 (Sept. 17, 1981). The Texas PUC adopted this discussion of cost of service ratemaking as a statement of policy.

1 power plant. However, AE has not included net salvage value in the depreciation rates it  
2 recovers. Given the possibility that power plants may be retired early, AE seeks an  
3 expense component to collect the amortized cost of its decommissioning request for three  
4 power plants (Decker, Fayette, and Sand Hill). AE retained a consultant, NewGen, to  
5 estimate the decommissioning cost for these plants. AE's total decommissioning cost  
6 estimate is \$80 million, and the amortized annual expense is \$19 million.<sup>10</sup>

7 **Q. DO YOU HAVE ANY CONCERNS ABOUT THE REQUESTED NON-NUCLEAR**  
8 **DECOMMISSIONING EXPENSE?**

9 A. Yes. I am concerned that the requested amount is excessive. AE is recovering the  
10 expense over a truncated period, rather than the normal life of plant recovery. This  
11 results in a "lumpy" payment and is not consistent with intergenerational equity,  
12 inasmuch as the total expense will be paid by consumers at the tail end of the plant's life.  
13 Furthermore, there are indications that the requested decommissioning cost estimate is on  
14 the high side. This is not surprising, since regulated utilities frequently prepare  
15 decommissioning cost estimates which are subsequently reduced by the regulatory  
16 authority. AE's own study shows that the average requested decommissioning cost is  
17 20% - 50% or more than the average PUC approved decommissioning cost.

18 **Q. WHAT ARE SOME OF THE INDICATIONS THAT THE DECOMMISSIONING**  
19 **ESTIMATE IS ON THE HIGH SIDE?**

20 A. First, on the cost/kW basis tabulated in the NewGen study, AE's chosen  
21 decommissioning cost amounts are higher than both average PUC approved amounts and

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<sup>10</sup> WP/D-1.2.5.

1 utility average requested amounts. Second, the decommissioning cost estimates contain  
2 no offsets for the value of water rights or potential sale of land. The study did not  
3 consider these potential offsetting benefits associated with decommissioning.<sup>11</sup> Third, the  
4 study gave no offsetting value to selling working components because this was  
5 considered “too uncertain.”<sup>12</sup> Fourth, the decommissioning estimates used contingency  
6 adders ranging from 10.7% - 30%. The Texas PUC does not permit contingency  
7 allowances greater than 10% for nuclear decommissioning,<sup>13</sup> and the scope and tasks for  
8 nuclear facilities are much more uncertain than for fossil plants. Fifth, the contingency  
9 adders for Sand Hill and Fayette decommissioning are not applied to salvage and  
10 recycling estimates, meaning that the contingency is applied only to positive elements of  
11 the estimates and not to negative offsets. In the Texas PUC’s most recent decision on net  
12 salvage value, the Commission found that a net salvage value of -2% should be applied to  
13 all production plant.<sup>14</sup> This implies that depreciation must recover 2% above gross plant  
14 cost to cover decommissioning. By comparison, the Decker decommissioning cost is  
15 almost one-half of the plant’s original gross cost.

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<sup>11</sup> AE Answer to ICA 4-6 (e) (f).

<sup>12</sup> AE Response to ICA 4-6 (d).

<sup>13</sup> PUC Subst. Rule 25.304(h).

<sup>14</sup> Application of Southwestern Power Co. for Change in Rates, Docket No. 43695, Order on Rehearing FOF No. 118-119.

1 **Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO NON-NUCLEAR**  
2 **DECOMMISSIONING EXPENSE?**

3 A. Based on the average decommissioning cost per kW approved by PUCs, as set out in  
4 Table 4 of the NewGen study,<sup>15</sup> I recommend reducing the total annual decommissioning  
5 expense by 48%. Schedule CJ-1 provides the details of the \$9.89 million revenue  
6 requirement reduction. Given that AE's estimates are near the upper boundary of  
7 decommissioning costs, my approach balances ratepayers' interest in containing costs  
8 recoverable through rates, while mitigating intergenerational inequity.

9 **C. Outside City Rate Discounts**

10 **Q. PLEASE DISCUSS AE'S PROPOSED RATE DIFFERENTIAL FOR INSIDE AND**  
11 **OUTSIDE CITY CUSTOMERS?**

12 A. The settlement of Docket No. 40627, the appeal to the PUC of AE's 2012 rate increase,  
13 included a rate discount of 5% for outside city customers. Although the settlement is not  
14 binding on subsequent rate changes, AE's current rate proposal assigns part of the  
15 revenue reduction to outside city customers in a manner that maintains outside city  
16 customers' discount off of the proposed inside city rates. The amount of the outside city  
17 discount included in the AE proposal is \$5.8 million.<sup>16</sup>

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<sup>15</sup> Appendix I page 99.

<sup>16</sup> AE Response to HURF Request 1-1.

1 **Q. DOES A COST BASIS EXIST FOR THE OUTSIDE CITY RATE DISCOUNT?**

2 A. No. Austin Energy is not aware of any cost basis for the inside / outside city rate  
3 differential.<sup>17</sup> Likewise, I am not aware of any costing principle which would suggest  
4 that outside city rates should be higher than inside city rates. If anything, one might  
5 argue the opposite. My assumption is that AE has continued the outside city rate  
6 discount in order to mitigate litigation risk.

7 **Q. WHAT IS THE EFFECT OF THE RATE DISCOUNT ON INSIDE CITY**  
8 **CUSTOMERS?**

9 A. The outside city discount reduces the overall level of revenue reduction available in this  
10 case. In addition, the revenue shortfall produced by the discount reduces the indicated  
11 current revenues of each respective customer class. Therefore, since 94% of the revenue  
12 shortfall associated with the outside city discount applies to the residential class, the  
13 discount contributes to the supposed subsidy of the residential class indicated by the  
14 CCOS study.

15 **Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO TREATMENT OF**  
16 **THE OUTSIDE CITY RATE DISCOUNT?**

17 A. The outside city rate discount can be continued, as proposed by AE. For cost of service  
18 purposes, I propose that a revenue imputation should be applied to classes, imputing the  
19 level of class revenues as if outside city customers paid a revenue level corresponding to  
20 inside city service. This “holds harmless” inside city customers for the settlement  
21 negotiated with representatives of outside city customers. Presumably AE agreed to the

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<sup>17</sup> AE Response to ICA Request 1-26.

1 outside city discount in order to avoid the risk that the Public Utility Commission would  
2 find the utility's revenue requirements excessive or reduce or eliminate the general fund  
3 transfer. However, it is unreasonable to force inside customers to pay higher rates as a  
4 result of the discount.

5 **Q. IS THIS TREATMENT SIMILAR TO REVENUE IMPUTATIONS APPLIED TO**  
6 **OTHER RATE DISCOUNTS?**

7 A. Yes. Sec. 36.007, PURA, is the provision governing rate discounts. Sec. 36.007(d) states  
8 that the allocable costs of serving customers served by discounted rates are not to be  
9 borne by the utility's other customers. In applying that provision to utilities with Sec.  
10 36.007 discounts, the shortfall associated with the discount is imputed to the current  
11 revenues of classes containing the customers receiving discounts.

12 **Q. IS THIS FAIR TO INSIDE CITY CUSTOMERS?**

13 A. Yes. The revenue imputation ensures that the cost of the discount is paid out of AE's  
14 margin rather than forcing outside city customers to pay higher rates to support the  
15 outside city discount. This is comparable to AE's decision when it originally agreed to  
16 the discount. After the Docket No. 40627 settlement was entered, AE did not increase  
17 inside city customers' rates to pay the shortfall. This means that the cost of the discount  
18 was paid out of the utility's margin.

1           **D.     Power Supply Stabilization Reserve**

2   **Q.     PLEASE DESCRIBE THE PROPOSED POWER SUPPLY STABILIZATION**  
3       **RESERVE.**

4   A.     Austin Energy proposes to change the Rate Stabilization fund into a “Power Supply  
5           Stabilization Reserve” and to use any funds remaining after closing the Emergency  
6           Reserve, and fully funding the Contingency Reserve for the Power Supply Stabilization  
7           Reserve.<sup>18</sup> Going forward, the reserve would be funded from net credit balances  
8           remaining in the Power Supply Adjustment, rather than including these as a credit in the  
9           calculation of the subsequent PSA. Austin Energy further recommends the reserve  
10          should maintain a cash balance between 90 and 120 days of Net Power Supply expenses.  
11          The purpose of the fund is to “mitigate unpredictable fluctuations in Net Power Supply  
12          costs in order to stabilize rates and meet affordability goals.”<sup>19</sup>

13 **Q.     IS IT REASONABLE TO HAVE A POWER SUPPLY STABILIZATION**  
14 **RESERVE?**

15 A.     Yes. The ERCOT market can be volatile, producing short term price spikes. Reframing  
16          the rate stabilization fund into a power supply stabilization fund is reasonable. Such a  
17          reserve helps to insulate ratepayers from market volatility.

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<sup>18</sup> Tariff Package at Bates 099.

<sup>19</sup> Tariff Package, Bates p. 101.

1 **Q. DO YOU AGREE WITH THE PROPOSED LEVEL OF FUNDING IN THE**  
2 **POWER SUPPLY RESERVE?**

3 A. No. Austin Energy recommends the reserve should maintain a cash balance between 90  
4 and 120 days of Net Power Supply expenses. This funding level is consistent with the  
5 recommendation made in the NewGen study found in Appendix I of the Master  
6 Appendices. After evaluating the risk to Austin Energy due to volatility in the ERCOT  
7 market, NewGen recommended funding a Power Supply Stabilization Reserve in the  
8 range of \$110 to \$160 million, equating to approximately 90 to 120 days of net power  
9 costs.<sup>20</sup> NewGen referred to this range as representing the “worst case scenario” and  
10 stated further: “If using the worst case scenario over the period is too conservative, an  
11 average approach yields a range between \$43 million and \$106 million when prorating  
12 historical costs up to the 2015 [ERCOT] price cap.”<sup>21</sup> Analyzing potential exposure  
13 “from a different perspective”, NewGen found “on average over the four-year period,  
14 cost exposure under maximum market pricing conditions that occurred at the time of the  
15 AE unit outages was approximately \$110 million.”<sup>22</sup>

16 I do not agree with funding this reserve based on the “worst case scenario” and  
17 assuming that all volatility will meet the ERCOT market price cap. The analysis does not  
18 appear to consider whether hedging or other contracts in the forward market could insure  
19 against simultaneous outages at STP and FPP during a period of price spikes, which is the

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<sup>20</sup> Appendix I, Bates stamped pages 475-477.

<sup>21</sup> Appendix I, Bates p.475.

<sup>22</sup> Appendix I, Bates p. 476.



1       worst case event. The benefits of a stabilization fund must be balanced with affordability  
2       for ratepayers. The difference between 120 days and 90 days' net power supply costs in  
3       the reserve fund ties up tens of millions of dollars more ratepayer money, and potentially  
4       prevents customers from receiving fuel cost refunds in the future.

5   **Q.   DO YOU AGREE WITH HOW THE PROPOSED RESERVE WILL BE**  
6   **FUNDED?**

7   A.   No, not entirely. I do not disagree with moving funds from the Emergency and  
8       Contingency Reserves as described above. However, I disagree with using net credit  
9       balances in the PSA to fund this reserve, rather than including them in an over/under  
10      collection calculation. The larger the required the balance in the fund, the greater the  
11      impact of this change on ratepayers. If this approach were currently in effect, it is  
12      unlikely ratepayers would have received the 11.3% decrease in the PSA that took effect  
13      on April 1.

14   **Q.   WHAT IS YOUR RECOMMENDATION?**

15   A.   First, I recommend funding this reserve at 90 days of net power supply costs. This level  
16       is supported by the NewGen study findings outside of the "worst case scenario". Second,  
17       I recommend the Power Supply Stabilization Reserve should not be funded with net PSA  
18       balances; credits should continue to flow to customers in the PSA calculation. These  
19       recommendations balance the goals of stabilizing the PSA with affordability goals.

1       **E.       General Fund Transfer (GFT)**

2       **Q.       WHAT IS THE GENERAL FUND TRANSFER?**

3       A.       As a municipally owned utility, AE is allowed by law to transfer a certain percentage of  
4               its revenues to the Austin City Council. A general fund transfer is analogous to the  
5               franchise fees and rate of return that is allowed by the PUC to be included in the  
6               calculation of the utility revenues and rates of an investor-owned utility. Unlike investor-  
7               owned utilities, these funds are then invested or spent towards purposes deemed to be  
8               priorities by an elected body that serves the public living in general service territory. AE  
9               currently pays an annual General Fund Transfer to the City of Austin in the amount of  
10              \$105 million, and AE has included this amount in the proposed test year revenue  
11              requirement, the lowest amount permitted under current city council policy.<sup>23</sup>

12      **Q.       WHAT IS YOUR RECOMMENDATION REGARDING THE GFT?**

13      A.       The appropriate level for the general fund transfer is a decision for the Austin City  
14              Council, and is a decision that will be made on a separate track during the city's budget  
15              review process. This is a very important input for the determination of AE's overall  
16              revenue requirement. This decision should be made with the utmost transparency,  
17              sufficient public input, and a proper balancing of public interests.

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<sup>23</sup> Tariff Package, p. 088.

1           **F.       Economic Development and Community Programs**

2   **Q.     DOES AUSTIN ENERGY CONTRIBUTE TO THE CITY’S ECONOMIC**  
3       **DEVELOPMENT DEPARTMENT?**

4   A.     Yes. Like other city departments, Austin Energy contributes to the City’s economic  
5       development efforts.<sup>24</sup> \$9,090,429 is collected through the customer charge.<sup>25</sup>

6   **Q.     WHAT IS THE PUBLIC UTILITY COMMISSION’S TREATMENT OF**  
7       **ECONOMIC DEVELOPMENT EXPENDITURES?**

8   A.     Prior to the first unbundling cost of service cases before the commencement of electric  
9       competition, the PUC directed electric utilities to limit economic development expense  
10      requests to the amounts allowed prior to competition. As with any other expense, the  
11      utility must still prove that the economic development expense is reasonable and  
12      necessary. AE’s economic development expenditures are larger than most Texas electric  
13      utilities. For example, Center Point Electric’s economic development program was \$2.4  
14      million in its last rate case, compared to more than \$9 million for AE. AE’s economic  
15      development amount is 0.77% of revenues, compared to Center Point expending 0.16%  
16      of its revenues on economic development.

17 **Q.     DOES AUSTIN ENERGY MAKE CONTRIBUTIONS TO COMMUNITY**  
18 **PROGRAMS?**

19 A.     Yes. Austin Energy describes contributions to Community Programs as “corporate  
20      sponsorships providing partnership and support to community, customer and civic

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<sup>24</sup> Designated economic growth and redevelopment service office (EGRSO) in the CCOS study.

<sup>25</sup> See Cost of Service Model Schedule H-5.4.

1 organizations and events.”<sup>26</sup> In 2015 these contributions included entities as diverse as  
2 Ballet Austin, American Diabetes Association, Community Mentor Initiative, Clean Air  
3 Force, Texas Public Power Association, and Texas Renewable Energy Industries  
4 Association. Several programs also receive funding from other city departments.<sup>27</sup>

5 **Q. HOW DOES THE PUBLIC UTILITY COMMISSION OF TEXAS TREAT**  
6 **DONATIONS TO COMMUNITY PROGRAMS BY UTILITIES?**

7 A. The PUC by rule<sup>28</sup> limits the amount of advertising, contributions and donations that can  
8 be included in rates to “three-tenths of 1.0% (0.3%) of the gross receipts of the electric  
9 utility for services rendered to the public.” Note this limitation includes advertising, as  
10 well as contributions and donations.

11 **Q. WHAT IS YOUR RECOMMENDATION?**

12 A. I recommend bringing greater transparency to Austin Energy’s transfers to the Economic  
13 Development Department and its donations and contributions to Community Programs.  
14 As an example, Council’s Austin Energy Oversight Committee received a briefing on  
15 Austin Energy’s current and recent spending in these areas on February 25, 2016.<sup>29</sup> A  
16 review of the video and transcript of this meeting indicates members of the City Council

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<sup>26</sup> AE Response to ICA 2-7

<sup>27</sup> See both AE Response to ICA 2-7 and Austin Energy General Fund Transfer and Payments for Services presentation of February 25, 2016 to the Austin Energy Utility Oversight Committee: <http://www.austintexas.gov/edims/document.cfm?id=250333>

<sup>28</sup> Public Utility Commission of Texas, CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS, Subchapter J. COSTS, RATES AND TARIFFS. DIVISION 1. RETAIL RATES §25.231. Cost of Service (b)(1)(E).

<sup>29</sup> <http://www.austintexas.gov/department/city-council/2016/20160225-aeuoc.htm>

1 are not fully aware of the amounts or in some cases, the purpose, of some of these  
2 expenditures that are contained in Austin Energy's budget.

3 At this time, I am not objecting to or proposing to eliminate expenditures for  
4 economic development or contributions to community programs. The City may  
5 legitimately decide to make these expenditures and contributions with funds generated by  
6 Austin Energy or any other city department. However, in my opinion, and consistent  
7 with the requirement that only reasonable and necessary expenses are allowed in cost of  
8 service, these are not *necessary* expenditures for providing utility service. Therefore, I  
9 recommend the Council transition toward treating Economic Develop program,  
10 donations, and contributions to community programs as part of the General Fund transfer.  
11 In this manner the economic development expenditures and donations would be clearly  
12 segregated from utility expenditures. This recommendation has no direct impact on rates  
13 since the expenditure is transferred to the GFT (unless and until the total amount of the  
14 expenditures is increased or decreased). The expenses would be clearly treated as  
15 nonutility expenses, improving transparency. When the city council establishes criteria  
16 for the size of the General Fund transfer, it should incorporate the intended budget for  
17 Economic Development expenses into that criteria.

#### 18 **IV. CLASS COST OF SERVICE**

##### 19 **A. Overview**

##### 20 **Q. WHAT IS A CLASS COST OF SERVICE (CCOS) STUDY?**

21 A. The CCOS is a fully allocated cost study which distributes the Company's costs to  
22 customer classes. The intent of the study is to allocate costs based on cost causation,

1 generally resulting in a portion of costs allocated on causal measures and the remainder  
2 of indirect costs following those costs. The CCOS is at best a broad benchmark for  
3 evaluating customer class cost responsibility. The CCOS can provide guidance to the  
4 regulator, but considerations other than the CCOS also are appropriate in determining the  
5 ultimate allocation of costs among customer classes.

6 **Q. HOW IS THE COST CAUSATION CRITERION APPLIED IN THE CCOS?**

7 A. Some costs are incurred directly to serve only an individual customer or set of customers.  
8 For example, substations are sometimes dedicated to serving an individual customer and  
9 can be directly assigned.

10 However, the provision of electric utility service is predominated by common and  
11 joint costs, which either support the overall enterprise or produce shared benefits for all  
12 or most customers. These costs often are assigned based upon indirect, and often weak,  
13 measures of causation. For example, overhead costs, such as Board of Director fees,  
14 might be allocated based upon measures as diverse as revenues, labor costs, energy sales,  
15 or demand. No single objective economic basis supports the allocation of these costs;  
16 therefore, the allocation decisions are subjective or based on rate making conventions.  
17 Ideally, the analyst selects a method that best recognizes the manner in which customer  
18 classes' characteristics contributed to the incurrence of utility investments and expenses.  
19 The manner in which a utility plans and installs an investment often informs the analyst's  
20 evaluation of causal factors related to classification or allocation of the investment.

21 The three major steps of the embedded cost of service study are functionalization,  
22 classification, and allocation. Functionalization is the procedure for separating costs into

functional segments, such as production, transmission, and distribution. The next two accounting steps, classification and allocation facilitate the recognition of causation. The classification procedure, which pools costs into general categories of causation (i.e., demand, customer, energy), is an intermediate step in determining the allocation factors that are used to divide costs among jurisdictions and customer classes.

**Q. PLEASE DESCRIBE YOUR REVIEW OF THE CCOS STUDY PREPARED BY AUSTIN ENERGY.**

A. My testimony reviews the reasonableness of functionalization, classification, and allocation decisions within the CCOS study. AE has made the excel workbook for the model publicly available. I have made recommendations with respect to a number of class cost of service issues, and I implemented those recommendations by modifying the AE model spreadsheets. The basis for my recommendations are discussed below.

**B. Production Demand**

**1. Causal Factors for Generation Capacity Costs**

**Q. WHAT ARE THE TWO MAJOR ALLOCATION METHODS APPLICABLE TO PRODUCTION PLANT?**

A. The two general types of allocation bases are annual energy use and peak demand. Although many variations of the two methods are available, the two approaches represent distinct dimensions of causation.

Peak demand represents the maximum use that occurs during a specified period of time (such as a year or a season). Peak demand measures, in theory, instantaneous maximum demand and not the time duration associated with the usage.

1           Average annual energy usage represents total kilowatts sales for the year.  
2           Average demand, which is annual sales divided by 8,760 hours, measures average hourly  
3           usage. The allocators for average demand and annual energy use are the same.  
4           Conceptually, average demand shows what the system hourly usage would be if no  
5           hourly peaks occurred.

6   **Q. PLEASE EXPLAIN THE DIMENSIONS OF CAUSATION ASSOCIATED WITH**  
7   **PEAK DEMAND AND ANNUAL ENERGY USE.**

8   A. Peak demand relates to the sizing of facilities. The megawatt capability of available  
9           generation plants constrains the level of instantaneous demand that can be  
10          accommodated. On the other hand, annual energy use and average demand pertain to  
11          costs that are affected by the duration of usage.

12           The relationship between peak demand and average demand is summarized by the  
13          calculation of “load factor.” Load factor is average demand divided by peak demand.  
14          Load factor indicates the proportion of energy consumption which is relatively constant.

15   **Q. HOW ARE THESE DIMENSIONS RELATED TO THE UTILITY’S**  
16   **PRODUCTION COSTS?**

17   A. During the course of a year, the utility’s operating mix and utilization of installed  
18          generating capacity changes constantly. In the prior paradigm of regulated wholesale  
19          power, the utility’s control center dispatched its generation to meet the utility native  
20          load’s real time demand at the lowest cost. In the new structure of the wholesale market,  
21          ERCOT dispatches all of the region’s generation to satisfy supply and demand consistent  
22          with market bids. As discussed in (4) below, ERCOT’s role in dispatching generation



1 does not change the fundamental characteristics of production economics. Baseload  
2 power plants are the most economical to operate and will be used on a more or less  
3 constant basis. Peaking power plants are less efficient in meeting demand over an  
4 extended period, but are particularly well-suited to accommodating increases in demand  
5 of a short duration. Intermediate power plants have operating characteristics that lie  
6 between baseload and peaking units. If power purchases on the open market are  
7 available at a lower operating cost than the utility's own generation, the lower cost  
8 purchases will be used to displace or supplement the operation of the utility's installed  
9 generation units. The process of dispatching generation is intended to achieve a mix of  
10 generation units that minimizes running costs. In the previous wholesale structure, the  
11 utility's dispatch software identified the optimal dispatch from moment to moment. In  
12 the current ERCOT system, market clearing prices over short time intervals reveal the  
13 mix of generation units which are least costly in real time.

14 If a utility was concerned only with building or buying enough capacity to meet  
15 maximum demand, the Company would construct or purchase only peaking capacity  
16 because such capacity requires the lowest fixed costs. However, higher fixed costs are  
17 incurred to build or acquire baseload and intermediate capacity, because such generation  
18 is the cheapest at meeting loads of constant duration.

19 **Q. HOW DO ELECTRIC UTILITIES DETERMINE THE MOST ECONOMIC**  
20 **GENERATING RESOURCES TO ACQUIRE AND BUILD?**

21 A. A municipal utility such as Austin Energy will consider a number of factors in addition to  
22 the pure economics of generation technologies. The factors include environmental

1 impact and climate change. In addition, the relative economics of available options will  
2 inform the recommendations of Austin Energy's planners. The primary planning  
3 assumption inputs for modeling future economic impacts are energy/fuel prices,  
4 forecasted system demands, ERCOT market price trends, and capital costs. Sensitivity  
5 studies can be conducted for different energy price and demand levels to evaluate the  
6 customer rate impact of various scenarios. The assumption for demand growth is most  
7 important in determining *when* new capacity is required and the energy/fuel input is most  
8 significant to determining the least cost *type* of capacity to be installed or acquired.

9 The economics of alternative portfolios of future generation resources will depend  
10 on critical trade-offs between each resource's capital cost and energy costs. High capital  
11 cost options have lower energy costs while less expensive capital cost options tend to  
12 have higher energy costs. Nuclear and coal capacity have very high capital costs but  
13 correspondingly low fuel costs. Gas fueled units have lower capital costs but rely upon a  
14 higher priced fuel. Even among gas plant technologies, higher capital costs are incurred  
15 to install technologies with lower heat rates.<sup>30</sup> Renewable technologies, such as solar,  
16 and wind, typically have a relatively high cost per kilowatt of capacity, but in return they  
17 produce zero fuel cost.

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<sup>30</sup> Heat rate is a measure of efficiency in converting fuel into electricity; a lower heat rate is more efficient.

1   **Q.   HOW SHOULD SYSTEM OPERATION AND PLANNING INFLUENCE THE**  
2   **SELECTION OF CLASS ALLOCATION FACTORS?**

3   A.   First, demands have to be served reliably throughout the year, which points toward  
4       allocating on the basis of multiple hours of demand.  Second, the allocation method  
5       should recognize that energy (or average demand) is a major determinant of the mix of  
6       installed generation resources and the economic dispatch of that generation.

7               The dual importance of demand and energy in developing production demand  
8       allocation methods is recognized in the National Association of Regulatory Utility  
9       Commissions (NARUC) Electric Utility Cost Allocation Manual (“NARUC CAM”):<sup>31</sup>

10              There is evidence that energy loads are a major determinant of  
11              production plant costs.  Thus, cost of service analysis may  
12              incorporate energy weighting into the treatment of production plant  
13              costs.  One way to incorporate energy weighting is to classify part  
14              of the utility’s production plant costs as energy-related and to  
15              allocate those costs to classes on the basis of class energy  
16              consumption.

17              The NARUC CAM cites the utility system planning process as justification:<sup>32</sup>

18              Generally speaking, electric utilities conduct generation system  
19              planning by evaluating the need for additional capacity, then,  
20              having determined a need, choosing among the generation options  
21              available to it.  These include purchases from a neighboring utility,  
22              the construction of its own peaking, intermediate or baseload  
23              capacity, load management, enhanced plant availability, and  
24              repowering among others.

25              The utility can choose to construct one of a variety of plant-types:  
26              combustion turbines (CT), which are the least costly per KW of

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<sup>31</sup> NARUC Electric Utility Cost Allocation Manual at 49.

<sup>32</sup> *Id.* at 53.

1 installed capacity, combined cycle (CC) units costing two to three  
2 times as much per KW as the CT, and baseloaded units with a cost  
3 of four or more times as much as the CT per KW of installed  
4 capacity. The choice of unit depends on the energy load to be  
5 served. A peak load of relatively brief duration, for example, less  
6 than 1,500 hours per year, may be served most economically by a  
7 CT unit. A peak load of intermediate duration, of 1,500 to 4,000  
8 hours per year, may be served most economically by a CC unit. A  
9 peak load of long annual duration may be served most  
10 economically by a baseload unit.

11 **Q. WHAT IS YOUR CONCLUSION?**

12 A. I agree with the NARUC CAM's description, above, of the relationship between the  
13 planning and operation of generation and the allocation of generation investment costs to  
14 customer classes. Ideally, the allocation methodology should recognize the types of  
15 generation facilities, including the manner in which each type of generation technology  
16 affects customer classes' capacity utilization.

17 **2. Austin Energy's Proposed 12 CP Method**

18 **Q. WHAT PRODUCTION DEMAND METHODOLOGY IS PROPOSED BY**  
19 **AUSTIN ENERGY?**

20 A. Austin Energy proposes an allocation based on each classes' 12 monthly peak demands  
21 coincident with the ERCOT monthly peak demands (12 CP). This is different than the  
22 Average & Excess Demand (AED) method adopted in the 2011 rate proposal. AE argues  
23 that 12 CP more effectively recognizes ERCOT's centralized dispatch of generation than  
24 AED.

1 **Q. DO YOU AGREE THAT 12 CP IS AN IMPROVEMENT OVER THE AED**  
2 **METHOD?**

3 A. Yes. The AED method does not recognize the diversity between ERCOT and Austin  
4 Energy demands. In addition, AED does a poor job of recognizing the impact of energy  
5 on planning and operating generation capacity.<sup>33</sup> AED effectively allocates costs on  
6 usage in only four hours of the year. At least 12 CP recognizes the reality that reliability  
7 is a concern throughout the year, and not just in the summer months. That said, 12 CP  
8 may be better than AED, but it is still inadequate to reflect cost causation. 12 CP is a  
9 peak demand methodology and does not directly recognize the impact of energy on  
10 planning and operating generation.

11 **Q. WHAT IS THE MOST SIGNIFICANT DEFICIENCY OF THE 12 CP METHOD?**

12 A. The proposed methodology does not recognize the existence of different types of  
13 generation facilities with varying cost characteristics that are critical to the planning and  
14 operation of generation capacity. AE's method uses 12 CP to allocate a homogenous  
15 annual capacity cost to each month. In reality, generation capacity costs are not  
16 homogenous. As previously discussed, Austin Energy incurred distinctly different  
17 capacity costs to serve baseload, intermediate, and peak periods. Although energy loads  
18 are a major determinant of production plant costs, as stated in the NARUC CAM, the 12  
19 CP method proposed by AE does not recognize the relationship between system energy  
20 use and the causation of generation investment.

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<sup>33</sup> Because the AED formula includes "average demand," it gives the appearance of recognizing energy. However, the algebraic effect of the AED formula largely cancels the impact of average demand. AED's recognition of energy is illusory. AED is a circuitous route to allocation on the basis of peak demand.

1                   **3. Base-Intermediate-Peak Method (BIP)**

2   **Q.    WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE**  
3   **PRODUCTION DEMAND METHOD FOR AE?**

4   A.    My recommendation is to utilize the Base-Intermediate-Peak Method (BIP) for allocating  
5          production plant among customer classes. I have developed a variant of BIP which  
6          recognizes the specific characteristics of AE's generation investment. The NARUC  
7          CAM identifies BIP as an accepted production demand methodology which falls within  
8          the "time-differentiated" category of methodologies.<sup>34</sup> BIP utilizes three time periods—  
9          Base, Intermediate, and Peak hours—and is based on the premise that baseload,  
10         intermediate, and peaking generation technologies and fuel types were incurred primarily  
11         to serve each of those time periods, respectively.

12 **Q.    ARE OTHER METHODS AVAILABLE WHICH ADDRESS THE SAME**  
13 **ALLOCATION OBJECTIVE?**

14 A.    A number of energy-based and time of use methodologies are available. Some of the  
15         methods are formulaic (e.g., Average and Peak or weighted Average and Excess), and  
16         therefore easier to administer from case-to-case. But these methods do not explicitly  
17         reflect the capacity cost differentials on AE's system or the effect of operating in the  
18         ERCOT market. Some of the methods are more data intensive because they reflect  
19         hourly time of use costs (e.g., probability of dispatch method). These methods are more  
20         difficult to administer, and may not be well-suited for recognizing ERCOT dispatch. In  
21         my judgement, BIP will produce class allocation results similar to more data intensive

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<sup>34</sup> NARUC CAM at 60-62.

1 time of use methods; any difference in results probably is not justified by the additional  
2 complexity of the capacity utilization models. BIP, as modified for my recommendation,  
3 represents a reasonable balance between the relative simplicity and complexity of the  
4 alternative methodologies.

5 **Q. PLEASE SUMMARIZE YOUR REASONING FOR RECOMMENDING BIP?**

6 A. First, the methodology explicitly recognizes the different types of generation  
7 technologies and fuel sources which were chosen by AE to serve the base, intermediate,  
8 and peak hours. Therefore, the method reflects the production cost causation criterion  
9 discussed in (1), above. Second, the methodology appropriately recognizes that, over the  
10 last 30 years, AE historically relied upon nuclear and coal generation to reduce total fuel  
11 cost. Third, the methodology reflects the more recent trend of using combined cycle and  
12 combustion turbine gas fired generation to meet loads of medium and short duration with  
13 the least costly capital investment. Fourth, AE has considered the BIP methodology and,  
14 therefore, is aware that it represents a reasonable methodology for the AE system. Fifth,  
15 AE's previous cost of service consultant, R.W. Beck (later called "SAIC"), recommended  
16 BIP during the public involvement (PIC) process for the 2011 rate request.<sup>35</sup> The  
17 consultant pointed out that BIP is consistent with the characteristics of ERCOT market  
18 dispatch.<sup>36</sup>

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<sup>35</sup> AE Response to ICA Request 7-11.

<sup>36</sup> R.W. Beck concluded that BIP mirrored the Probability of Dispatch method (POD) by "maintaining a link between resource dispatch and load requirements, but in a manner more consistent with the ERCOT nodal market design." Ibidem.

1 **Q. ALTHOUGH AE CONSIDERED BIP IN THE PREVIOUS RATE CASE, AE**  
2 **RECOMMENED THE USE OF AVERAGE & EXCESS DEMAND (AED). IS**  
3 **THIS A REASON TO REJECT BIP IN THIS RATE REQUEST?**

4 A. No. AE's position in the previous rate request used the BIP result to support the "±5% of  
5 cost" residential revenue criterion. So, the suggestion that BIP had no influence on the  
6 previous class revenue distribution is inaccurate. Furthermore, the 2012 rate request was  
7 based on a 2009 test year, a time period prior to the implementation of ERCOT dispatch.  
8 AE has pointed to this distinction to justify the change in its recommended method (from  
9 AED to 12 CP) in this case. In my view, BIP is a better match with ERCOT market  
10 characteristics than 12 CP alone.

11 **Q. PLEASE DESCRIBE THE GENERATION TECHNOLOGIES ASSIGNED TO**  
12 **BASE, INTERMEDIATE, AND PEAK UTILIZATION.**

13 A. The BIP method identifies the plant investment assignable to base, intermediate, and peak  
14 utilization.<sup>37</sup> The RFP WP/F-2.3.1 provides the sub-functionalization of production  
15 plant. South Texas Project (nuclear) and Fayette Power Plant (coal) are assigned as  
16 baseload, because these units are operated as much as possible throughout the year. From  
17 an economic perspective, Austin Energy's objective is to maximize the capacity factor  
18 for these two plants in order to take advantage of their low variable costs. Steam-fired  
19 gas units and combined cycle gas units at Decker Power Plant and Sand Hill Energy

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<sup>37</sup> When AE has prepared BIP allocations, it appears that revenue requirements rather than plant investment was used for weighting the three periods. Production demand methods are considered to be generation plant allocation factors, and it is customary to assign *plant costs* to time periods, which is reflected in my formulation of BIP.



Center are assigned as intermediate generation. Typically intermediate generation will have capacity factors ranging from 20% - 50%, depending on their variable costs and market conditions. Intermediate periods frequently include shoulder demands. The gas generation categorized as “Quick Dispatch” consists of combustion turbines at the Decker and Sand Hill sites, and are assigned to Peak. As the name implies, these units can be started quickly in order to meet loads of short duration. AE has minor amounts of investment in wind and solar plant, which are properly included in the baseload category. Renewable investment is not dispatchable, but the plants share the energy characteristics of baseload generation. Solar and wind power involve relatively high capital costs per kW which are incurred in order to achieve zero fuel cost. Therefore, the capital cost provides energy value to AE’s generation portfolio.<sup>38</sup>

**Q. PLEASE EXPLAIN HOW CLASS ALLOCATION FACTORS ARE DEVELOPED FOR BIP.**

A. The Base capacity is allocated on an energy basis, because baseload generation is operated at maximum capacity factor in order to achieve maximum energy value throughout the year. The Intermediate period is allocated partially on an energy basis and partly on the basis of 12 CP (ERCOT), because intermediate generation has a role which is a mixture of Peak and Baseload characteristics.<sup>39</sup> The capacity factor of these units is a

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<sup>38</sup> Most of AE’s renewable generation is purchased and, therefore, is paid through the PCA. As a practical matter, renewable generation has little or no current effect on BIP. However, as AE constructs or installs renewable generation in the future, it will affect the baseload component of BIP.

<sup>39</sup> This varies from the AE method for applying BIP, which uses only 12 CP for intermediate units. However, AE’s approach ignores the energy value of combined cycle units which have substantial hours of use throughout the year. Energy is a principal consideration in choosing whether to install a combined cycle or combustion turbine.

1 proxy for the portion of plant cost which is energy-related. Based on the average  
2 weighted capacity factor for AE's intermediate units, 34% of Intermediate is allocated on  
3 energy and 66% is allocated on a 12 CP basis. The Peak capacity is allocated on the  
4 basis of the ERCOT 4 summer coincident peaks (4CP). The summer peaks provide  
5 higher prices which justify the operation of high variable cost generators. This reflects  
6 the role of quick start peak generation in meeting the primary peak demands. I developed  
7 two variations of BIP class allocation factors.

8 **Q. WHAT ARE THE TWO VERSIONS OF BIP THAT YOU PREPARED?**

9 A. Class allocation factors for both versions are shown on Schedule CJ-2. The "net plant"  
10 version (BIP-N) is based on net plant values for the generation. This reflects both  
11 depreciation and investment cost in "as spent dollars." The problem with this approach is  
12 that it may distort the relative value of Base, Intermediate, and Peak hours simply due to  
13 the timing of plant installation dates. For example, the South Texas Project and Fayette  
14 Power Plant were constructed many years ago, and much of the original investment has  
15 been paid off by customers already. If all plant costs are converted to the same year's  
16 dollars, the values for Base, Intermediate, and Peak generation can be compared on an  
17 economically equivalent basis. Therefore, I prepared a "replacement cost" version of BIP  
18 (BIP-R), which adjusts the Base, Intermediate, and Peak ratios to reflect the costs of  
19 generating technologies in 2014 dollars. This version utilizes the U.S. Department of  
20 Energy (DOE) generation cost estimates (installed capital cost per kW \$2014) for current  
21 nuclear, coal, combined cycle, and combustion turbine technologies to develop Base,  
22 Intermediate, and Peak plant cost relationships. In my experience, the DOE generation

1 cost estimates are used by electric utilities (including Austin Energy), regulatory  
2 commission, and regional transmission organizations as generic plant costs. The  
3 replacement cost version of BIP (BIP-R) also is shown on Schedule CJ-2.<sup>40</sup>

4 **Q. WHICH OF THE TWO VERSIONS OF BIP DO YOU RECOMMEND?**

5 A. My recommendation is to use BIP-R, and my class cost of service results incorporate  
6 BIP-R as the production demand allocation factor. In my opinion, plant cost comparisons  
7 based upon equivalent overnight dollars provide the most reasonable results.

8 **Q. HAVE YOU COMPARED THE RESULTS OF BIP-R TO ANY OTHER ENERGY**  
9 **WEIGHTED PRODUCTION DEMAND METHODOLOGIES?**

10 A. Yes. The NARUC CAM sets out a formulaic approach termed Average & Peak-12 CP  
11 (A&P-12 CP). This methodology classifies a portion of production plant equal to the  
12 applicable load factor as energy-related, and allocates the remainder using 12 CP. Under  
13 certain simplifying assumptions, this method is mathematically equivalent to a time of  
14 use capacity utilization method.<sup>41</sup> One of the simplifying assumptions of the proof is that  
15 costs do not vary by types of technology. In order to incorporate a more realistic  
16 assumption, I adjusted the load factor in A&P/12 CP to reflect the cost differential  
17 between installing a new combined cycle units instead of a combustion turbine.<sup>42</sup> AE's

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<sup>40</sup> The allocation factors for BIP-R are nearly the same as using gross plant for the relative weighting of Base, Intermediate, and Peak.

<sup>41</sup> "Capacity Utilization Responsibility: An Alternative to Peak Responsibility," Dr. Michael Proctor, Public Utility Fortnightly at 31, April 26, 1983.

<sup>42</sup> Based on the DOE generation cost assessment, an advanced combustion turbine installation cost cost/kW is 33% less than an advanced combined cycle capital cost. Therefore, the load factor weighting for peak demand is reduced by that percentage, and the load factor weighting for average demand is adjusted accordingly so that the formula equals 100%. This results in a formula based on 80% energy and 20% 12 CP.

1 resource plan includes the addition of a new combined cycle plant, and the alternative to  
2 this type of unit is a combustion turbine peaker; therefore, the capital cost differential  
3 between combined cycle and peaker generation can be used to depict the lower capital  
4 cost of meeting peak. The resulting Adjusted A&P-12 CP produces class allocation  
5 factors almost the same as BIP-R, as shown on Schedule CJ-2. This confirms that a time  
6 of use based methodology will produce results approximately the same as BIP-R.

7 **Q. DOES AE'S CURRENT RESOURCE PLAN INCLUDE FUTURE NON-**  
8 **DISPATCHABLE RESOURCES WHICH WILL ENABLE THE UTILITY TO**  
9 **REDUCE PEAK DEMAND AT A LOWER COST THAN A GAS-FIRED**  
10 **COMBUSTION TURBINE?**

11 A. Yes. AE's current resource and climate protection plan includes large quantities of  
12 projected demand-side management measures which incur a levelized capital cost 36%  
13 less expensive per mWh than a combustion turbine.<sup>43</sup> Therefore, the peak component of  
14 BIP may reflect an upper limit on the cost of serving peak periods. Solar non-  
15 dispatchable resources may provide energy value at a levelized capital cost roughly  
16 equivalent to new coal and nuclear capacity.<sup>44</sup>

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<sup>43</sup> Slide presentation referenced in the Supplemental Response to ICA 4-7.

<sup>44</sup> *Ibidem.* Levelized capital cost per mWh assumptions used by Austin Energy: Photovoltaic solar \$46 (West Texas) and \$93 (local); coal \$55 and nuclear \$105.

1                   **4. BIP Consistency with ERCOT Market**

2   **Q.     GIVEN THAT AUSTIN ENERGY OPERATES IN THE ERCOT MARKET,**  
3           **PLEASE EXPLAIN WHY IT IS IMPORTANT THAT THE PRODUCTION**  
4           **DEMAND METHODOLOGY RECOGNIZES TYPES OF GENERATING**  
5           **PLANTS?**

6   A.     Generators (including AE) submit real time pricing bids into the ERCOT market, and  
7           ERCOT dispatches generation on a five minute or less basis, utilizing the market clearing  
8           price for the demand level at that instant. Under ordinary conditions, generators will  
9           submit bids close to the generation unit's variable cost in order to ensure that the unit  
10          operates when it is economic to do so. As a result, generating unit's annual hours of  
11          operation will depend on its variable cost. And, as noted previously, higher capital cost  
12          plants tend to have lower variable cost, and vice versa. For generation planning  
13          purposes, the Price Duration Curve for ERCOT is more relevant to Austin Energy than  
14          the load characteristics of the individual utility.<sup>45</sup> The Price Duration Curve will provide  
15          information on the number of hours that each generation unit is likely to operate, thereby  
16          allowing the generators' management to estimate the probable net revenues produced by  
17          each plant. Thus, information regarding the ERCOT market is critical to AE's decisions  
18          to operate and make additions to its generation fleet.

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<sup>45</sup> The price duration curve for an annual period in ERCOT will show the number of hours associated with each pricing interval in the ERCOT market. ERCOT's price duration curve is shown on Figure 3-4 at page 3-15 of AE's Tariff Package Proposal.

1 **Q. CAN YOU PROVIDE AN ILLUSTRATION BASED ON THE TYPES OF**  
2 **GENERATING UNITS OWNED BY AE?**

3 A. Yes. The table, below, is based on the price duration intervals in the 2014 ERCOT State  
4 of Market Report. The variable costs for nuclear and coal units are based on the  
5 independent market monitor's estimate, and the price of gas is assumed to be \$4.90 per  
6 mmbtu. I have assumed an average heat rate of 9,000 for combined cycle and  
7 conventional steam units and 10,500 for conventional combustion turbines, plus \$2.00  
8 per mWh for gas plant variable O&M. These assumptions and results are for illustrative  
9 purposes only. As shown in the table, only coal and nuclear plants are positioned to  
10 operate during most of the hours within the 0 - \$50 per mWh interval. Conventional  
11 steam and combined cycle units are positioned near the upper limit of the \$50 price  
12 interval and are likely to operate only during a relatively small slice of hours for that  
13 interval. Combustion turbines have a variable cost above the \$50 price interval, and  
14 therefore can operate in less than 8% of annual hours.<sup>46</sup> The highest capital cost plants  
15 can operate in most of the lowest price interval, which includes 91% of hours. The  
16 second highest capital cost units, intermediate, can operate for a number of hours midway  
17 between the peak and baseload plants.

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<sup>46</sup> 693/8,760=8%. Note that total hours in table do not equal 8,760 because the table excludes price intervals below \$0.

### ERCOT Market Price Intervals and Hourly Frequency

<i>Price Interval (\$/mWh)</i>	<i>Hours</i>	<i>Variable Cost</i>
<b>0 - \$50</b>	<b>7936</b>	
Nuclear		\$ 8.00
Coal		\$ 24.00
<b>Over \$50</b>	<b>693</b>	
Conventional CC & Steam Gas		\$ 46.10
Combustion Turbine		\$ 53.45

*(Avg. ERCOT North and South Zones, 2014)*

**Q. HOW DO HOURS OF OPERATION RELATE TO THE DECISION TO INSTALL GENERATION?**

A. Both the likely frequency of hourly operation, as well as prices in those hours, will determine the revenues produced by each type of generation plant. The ERCOT Independent Market Monitor performs a “Net Revenue” analysis for different generator technologies, based on hourly prices net of variable cost. For generators contemplating the installation of new plants, the net revenues can be compared to the annual capital cost for the new plant in order to estimate profit. The market monitor’s Net Revenue estimates for 2014 can be arranged into a Base-Intermediate-Peak format, as shown below.

1

2                                   **Net Revenues: 2014 ERCOT Market Report**<sup>47</sup>

Baseload	\$105 - \$227 kW-yr.
Intermediate	\$57 kW-yr.
Peak	\$37 kW-yr.

3   **Q.    TAKING INTO ACCOUNT THE OPERATION OF THE ERCOT MARKET,**  
4       **SHOULD AUSTIN ENERGY ENCOURAGE ITS CUSTOMERS TO USE**  
5       **ELECTRICITY DURING THE LOW PRICE HOURS OF THE PRICE**  
6       **DURATION CURVE?**

7   A.   Not necessarily. This highlights a distorted assumption underlying peak responsibility  
8       production demand methods. Narrow peak responsibility allocation methods imply that  
9       base-related costs associated with off-peak usage should be considered “free.” But this  
10      ignores the opportunity cost of selling Austin’s baseload generation in the market.  
11      Encouraging off-peak usage indirectly decreases the net revenues which can be produced  
12      by baseload generation.<sup>48</sup> Peak responsibility methods assume that generation plant in  
13      excess of off-peak load is idle. This is certainly not the case for Austin Energy’s  
14      baseload plants, which will operate in as many hours as possible, regardless of its  
15      customers’ off-peak usage.

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<sup>47</sup> 2014 ERCOT State of the Market Report at page xvii.

<sup>48</sup> As a load serving entity, Austin Energy must purchase power for its customer’s off-peak usage at the market clearing price. If AE has baseload capacity available in excess of its own off-peak loads, AE can generate excess power at that same market price, thereby producing “profits” to offset utility costs paid by its customers.



1 **Q. PLEASE SUMMARIZE YOUR POSITION?**

2 A. Production demand allocation methods like my recommended BIP methodology are  
3 consistent with the capital-energy trade-offs associated with generation entry into the  
4 ERCOT market.

5 **C. Production Non-Fuel O&M Expense Classification**

6 **Q. DO YOU AGREE WITH AE'S CLASSIFICATION OF PRODUCTION NON-**  
7 **FUEL O&M ACCOUNTS?**

8 A. No. AE classified all production non-fuel O&M expense as demand-related. The  
9 customary approach is to split these expenses between demand and energy. Although I  
10 sometimes disagree with the demand/energy split for generation O&M applied by other  
11 utilities, I cannot recall another bundled electric utility which owned multiple generating  
12 units that applied a 100% demand classification to the expenses. Among current bundled  
13 electric utilities in Texas, SWEPCO, SPS, and El Paso Electric Co. classify a portion of  
14 production non-fuel O&M expense as energy-related. The AE cost of service model  
15 includes a workpaper (WP F-2.4) entitled "develop production allocators for cost  
16 accounting method" which divides the production non-fuel O&M expenses between  
17 energy and demand, but AE chose not to use this classification in the cost of service  
18 study presented in support of its proposed tariffs.

19 **Q. HOW DO YOU PROPOSE TO CORRECT THE CLASSIFICATION OF**  
20 **PRODUCTION NON-FUEL O&M EXPENSE?**

21 A. The most reasonable approach is to utilize the classification recommended in the  
22 NARUC CAM. This method represents an accepted convention, and has been adopted

1 by the Texas PUC in the past. Based upon my review, AE's unused "cost accounting  
2 method" appears to be consistent with the NARUC CAM.

3 **Q. PLEASE DESCRIBE THE NARUC COST ALLOCATION MANUAL'S METHOD**  
4 **FOR CLASSIFYING PRODUCTION NON-FUEL EXPENSE.**

5 A. Some accounts are classified entirely as either energy or demand. However, most  
6 accounts are split between energy and demand in proportion to the labor and commodity  
7 costs in the account. For these accounts, labor costs are considered more fixed in nature,  
8 and are classified as demand-related, while commodities are considered more variable in  
9 nature, and are classified as energy-related. This approach is commonly referred to as a  
10 cost accounting method; from a cost accounting perspective, labor costs are fixed over a  
11 short run period and materials and supplies tend to be consumable or disposable. The AE  
12 cost of service workpaper referenced above, WP/F-2.4, is based on the same labor  
13 proration method. Therefore, I recommend modifying the cost of service study to apply  
14 the classification designated by AE as the cost accounting method.

15 **Q. WHY IS A SUBSTANTIAL PORTION OF GENERATION MAINTENANCE**  
16 **EXPENSE ENERGY-RELATED?**

17 A. Like most mechanical devices, the frequency of maintenance for production facilities is  
18 generally a function of the wear and tear associated with the duration of operating the  
19 facilities. It is not reasonable to assign causal responsibility for maintenance costs solely  
20 to peak hours during the year.

1 **Q. IS SOME PORTION OF PRODUCTION OPERATION EXPENSE PROPERLY**  
2 **CLASSIFIED AS ENERGY-RELATED?**

3 A. Yes. Certain expenses such as coolants, lubricants, nuclear fuel moderation fluids, and  
4 other consumable supplies vary with the annual generation of the production facilities.  
5 Moreover, baseload facility operating expenses obviously are needed to support  
6 operations throughout the year.

7 **Q. HOW DOES THE CLASSIFICATION AFFECT CUSTOMER CLASS**  
8 **ALLOCATION?**

9 A. Demand classified accounts are allocated on the basis of the production demand  
10 allocator. Energy classified accounts are allocated on the basis of class energy use.

11 **D. Functionalization/Classification of A& G Account 920 (Salaries)**

12 **Q. WHAT IS ADMINISTRATIVE & GENERAL (A&G) ACCOUNT 920?**

13 A. As a matter of accounting definition, this account contains salaries and wages which  
14 cannot be attributed to any particular function of the utility. Examples of typical  
15 expenses include the chief executive officer, general corporate officers, the treasury and  
16 finance departments, the human resources department, corporate strategic planning,  
17 shareholder services, etc. These are common costs of the utility which are only weakly  
18 associated with any particular class allocation factors.

19 **Q. HOW DOES AE FUNCTIONALIZE ACCOUNT 920?**

20 A. Functionalization is process of assigning the costs to production, transmission,  
21 distribution, and customer functions. The Company allocates the expense in proportion  
22 to labor costs within each functional category (Labor excluding A&G). This is not

1 unusual; many utilities classify this account to labor. Note that each functional group  
2 (such as production O&M) includes the supervisors and management for the group's  
3 work force within the functional labor expense. Thus, A920 management salaries are not  
4 directly involved in supervising the workers included in labor excluding A&G.  
5 Typically, Account 920 personnel are responsible for a broad scope of management  
6 activity, not just supervising the utility's employees. In this particular case, my  
7 recommendation is to modify the functionalization allocator for A920.

8 **Q. WHAT IS THE PROPER CRITERION FOR SELECTING AN APPROPRIATE**  
9 **ALLOCATOR FOR A920?**

10 A. Because none of the potential allocators are strongly related in a causal sense to A920,  
11 the selection should focus on the extent that the allocator spreads A920 salaries and  
12 wages broadly and equitably across utility functions. Austin Energy's top management is  
13 responsible for aspects of the utility's operations, and it makes sense that their salary  
14 costs are recovered broadly across functions.

15 **Q. WHY DO YOU PROPOSE TO CHANGE THE USE OF A LABOR<sup>49</sup>**  
16 **ALLOCATION FOR THIS ACCOUNT?**

17 A. Because AE is a non-managing partner in the South Texas Project and Fayette Coal  
18 Plant, AE's class cost of service study does not include labor personnel at those plants  
19 within the labor allocation factors (except for relatively minor salary expense associated  
20 with AE personnel who oversee the plants). Although these two plants constitute  
21 approximately 55% of non-fuel production expense, the plants' labor expense is not

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<sup>49</sup> The functionalization allocator is designate PayrollxAG.

1 included in the labor allocator. As a result, the labor allocation will understate the  
2 magnitude of the production function. For this reason, an exception to the typical  
3 practice of using a labor allocation for A920 is justified.

4 **Q. WHAT DO YOU PROPOSE AS THE ALLOCATION METHOD FOR A920?**

5 A. My recommendation is to allocate A920 on the basis of non-fuel O&M expense,  
6 excluding A&G.<sup>50</sup> As illustrated in the comparison below, this method spreads the A920  
7 expenses more broadly across functions than the labor allocation. The O&M allocator  
8 assigns a similar percentage of cost to Production as the Gross Plant allocator. The labor  
9 allocator, by comparison, understates the allocation of cost to Production. This confirms  
10 my inference, above, that the exclusions of FPP and STP labor costs from the labor  
11 allocator biases the Production results downward.

**Functional Percentages**

	<b>Labor</b>	<b>Plant</b>	<b>NF O&amp;M</b>
<b>Production</b>	21%	47%	46%
<b>Transmission</b>	9%	12%	24%
<b>Distribution</b>	36%	40%	12%
<b>Customer</b>	34%	.1%	18%
<b>Total</b>	100%	100%	100%

12 **Q. IS YOUR RECOMMENDATION AFFECTED BY THE FACT THAT THE COST**  
13 **OF SERVICE STUDY DIRECTLY ASSIGNED SOME A&G EXPENSES TO**  
14 **PRODUCTION?**

15 A. No. The cost of service study *should* directly assign any common costs which can be  
16 identified as pertaining to a particular function. This is a step that is taken before

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<sup>50</sup> This allocator is designated O&MxAG in the cost of service study.

1 allocating common costs. But the existence of direct assignment does not affect the  
2 choice of allocation methods for the remaining common costs. If the \$3.2 million of  
3 A920 direct assignment is included with the labor allocation, the production ratio  
4 increases to 28%. Yet, this is still 19 – 20 percentage points below the production  
5 allocation percent for O&M and Plant methods.

6 **Q. WHY IS IT IMPORTANT TO ALLOCATE THESE COMMON COSTS IN**  
7 **REASONABLE PROPORTIONS ACROSS FUNCTIONS?**

8 A. The customer classes utilize functions in different proportions. Virtually all classes are  
9 served by the production function. However, transmission voltage customers are not  
10 served by the distribution function. The vast majority of customer functions are assigned  
11 to the residential class. Therefore, an allocation of A920 which is not proportionate to  
12 the resources devoted to each function will produce biased results for particular customer  
13 classes.

14 **Q. IS AN O&M ALLOCATOR REASONABLY RELATED TO THE**  
15 **RESPONSIBILITIES OF MANAGEMENT ASSOCIATED WITH ACCOUNT**  
16 **920?**

17 A. Yes. Presumably the top management of the Company pay attention to overall expense  
18 levels, whether associated with labor or procurement of materials. In addition, the O&M  
19 allocation will reflect contract labor expense, as well as employee wages. Austin  
20 Energy's management should be no less concerned about the level of contract labor cost  
21 than they are about employee expense.

1 **Q. SHOULD THIS ALLOCATOR CHANGE BE CARRIED THROUGH TO THE**  
2 **PROCESS OF SUB-FUNCTIONALIZATION?**

3 A. Yes. The A&G expense assigned to each function is classified to sub-functions based on  
4 the function's labor expense. The sub-functionalization that produces the most  
5 significant effect on classes arises within the distribution function, because sub-  
6 functionalization spreads costs to voltage levels. For the same reason that the A920  
7 functionalization method should be changed from labor to non-fuel O&M, my  
8 recommendation is that distribution function A920 costs should be sub-functionalized on  
9 the basis of distribution O&M expense, instead of distribution payroll expense.

10 **E. Classification and Allocation of Transformer/Substation Investment**

11 **Q. DO YOU DISAGREE WITH AE'S CLASSIFICATION AND ALLOCATION OF**  
12 **TRANSFORMER INVESTMENT?**

13 A. Yes. The Company classifies transformer costs as 100% demand-related. Line  
14 transformers and related devices (such as capacitors and voltage regulators) are recorded  
15 in A368, which AE allocates on a 12NCP basis to secondary classes. Transformers and  
16 related devices installed in distribution substations are recorded in A362, Station  
17 Equipment, which AE allocates on a 12NCP basis to both secondary and primary classes.  
18 12NCP reflects the average of each class' monthly peak demand. My recommendation is  
19 to allocate A362 and A368 costs on the basis of class summer energy use. Energy use  
20 recognizes the role of transformers and substations in producing energy losses. Limiting  
21 the energy use to summer months recognizes the effect of high demand periods and  
22 higher ambient temperatures on transformer capacity. This allocation is similar to Center

1 Point Electric's use of summer kWh to assign transformer investment to customer  
2 classes. I will discuss transformers and substations in more detail below.

3 **Q. PLEASE DISCUSS HOW TRANSFORMER INVESTMENT IS RELATED TO**  
4 **ENERGY LOSSES.**

5 A. The cost-effectiveness of selecting particular transformers is influenced by the trade-off  
6 between up-front investment costs to achieve higher energy efficiency and the long term  
7 reduction in energy costs due to fewer losses. For many years, electric utilities  
8 considered energy cost reduction trade-offs in transformer procurement. However, five  
9 years ago, the Department of Energy ("DOE") implemented significantly higher energy  
10 efficiency performance standards for utility transformers.<sup>51</sup> Although the influence of  
11 energy on transformer investment has always existed, recent federal changes have  
12 provided a more apparent illustration of the effect. Based on my review of this issue in  
13 various electric utility cases, the higher investment cost of meeting the transformer  
14 energy efficiency standard appears to be in the range of 10% - 24%.<sup>52</sup> Austin Energy  
15 estimates a 9% increase in network vault transformers due to DOE 2016 energy  
16 efficiency standards.<sup>53</sup> With respect to previous DOE transformer standards, AE  
17 preempted the cost impact by installing transformers which met the new standards before

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<sup>51</sup> 10 CFR 431.191, *et. seq.*

<sup>52</sup> For example, the transformer price increases to meet the efficiency standard is 18% for Center Point Electric Delivery and 24% for Connecticut Light & Power Co.

<sup>53</sup> AE Response to ICA Request 1-6.



1 the regulations went into effect.<sup>54</sup> Transformer procurement costs affect energy loss  
2 levels, which in turn affect AE's fuel and purchased power costs.

3 **Q. CAN YOU EXPLAIN HOW TRANSFORMERS ARE RELATED TO ENERGY**  
4 **LOSSES?**

5 A. Transformers are one of the largest sources of energy losses on the electric delivery  
6 system. These losses result in higher fuel cost to supply end use customers, particularly  
7 secondary customers.

8 Transformer energy losses are categorized as either core losses, which occur  
9 8,760 hours per year, as long as the transformer is connected to the system; or load losses  
10 (sometimes called winding losses), which vary with the amount of power flowing  
11 through the transformer. Both forms of loss can be reduced through the purchase of  
12 transformers that are designed to achieve greater efficiency. However, the increased  
13 efficiency of the transformer generally results in higher installed investment cost. DOE  
14 performed cost-effectiveness analyses of lifetime costs (transformer installation cost) and  
15 benefits (energy savings) in order to determine federal efficiency standards for utility  
16 transformers. The net present value savings in fuel costs from more efficient  
17 transformers is very significant.

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<sup>54</sup> *Ibidem.*

1 **Q. ARE CAPACITORS AND RELATED DEVICES IN ACCOUNT 368 USED TO**  
2 **REDUCE ENERGY LOSSES?**

3 A. Yes. Properly applied capacitors “return their investment very quickly” by saving  
4 “significant sums of money in reduced losses.”<sup>55</sup>

5 **Q. WHAT ARE THE IMPLICATIONS FOR COST ALLOCATION?**

6 A. Investment costs for transformers have been, and will be, incurred to reduce customers’  
7 variable energy expenses, and the benefits of such investment should reflect class energy  
8 use on a kWh basis. Furthermore, distribution substations convert transmission voltage  
9 to distribution voltage, and therefore also are a source of energy losses. Station  
10 equipment in A362 consists of transformers, capacitors, and similar devices which should  
11 be allocated on a comparable basis to A368, except that the allocation applies to primary  
12 voltage customers as well as secondary customers.

13 **Q. IS YOUR USE OF A KWH ALLOCATOR CONSISTENT WITH A STUDY**  
14 **COMMISSIONED BY NARUC REGARDING COST ALLOCATION FOR**  
15 **UNBUNDLED DISTRIBUTION COSTS?**

16 A. Yes. The Regulatory Assistance Project (“RAP”) published a report for NARUC on the  
17 implications of unbundling for distribution rate design.<sup>56</sup> The report recommended that a  
18 portion of distribution costs be allocated on an energy basis, for both embedded and  
19 marginal cost of service studies:<sup>57</sup>

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<sup>55</sup> Electric Power Distribution Equipment and Systems at 273, T.A. Short, EPRI Solutions, Inc.

<sup>56</sup> Weston, Harrington, Moskowitz, Shirley, And Cowart, Charging For Distribution Utility Service: Issues In Rate Design, (Dec. 2000).

<sup>57</sup> *Id.* at 32, 39 [references omitted].

1 [Embedded Cost of Service Study:]

2 A similar kind of analysis can inform the design of distribution  
3 systems, as it also does transmission. The question is whether  
4 there is some amount of capacity in excess of the minimum needed  
5 to meet peak demand that can cost-effectively be installed. The  
6 additional capacity — larger substations, conductors, transformers  
7 — will reduce energy losses; if the cost of energy saved is greater  
8 than that of the additional capacity, then the investment will be  
9 cost-effective and should be made. For the purposes of cost  
10 analysis and rate design, these kinds of distribution investments are  
11 rightly treated as energy-related.

12 [Marginal Cost Study:]

13 As discussed earlier, to the extent that distribution investments are  
14 made to offset energy needs, there are necessarily costs associated  
15 with avoiding those investments. Losses, heat build-up, frequency  
16 of overloads, etc., are aspects of energy use that affect distribution  
17 investment and operations; thus there are marginal energy costs in  
18 distribution.

19 According to the RAP report, distribution investments that are incurred to reduce  
20 energy expense are appropriately allocated on an energy basis. My recommendation is  
21 consistent with this conclusion.

22 **Q. DO ANY TEXAS UTILITIES UTILIZE CLASS KWH USAGE TO DEVELOP**  
23 **THE ALLOCATORS FOR TRANSFORMERS?**

24 A. Yes. Center Point Electric uses class summer kWh consumption to develop its  
25 allocation. In Docket No. 38339, the Commission reversed the Proposal for Decision's  
26 acceptance of my proposal to classify a portion of transformer investment on overall class  
27 energy use, citing evidence that Center Point's allocation process already uses energy

usage to allocate transformers.<sup>58</sup> My recommendation in this case is consistent with that process, recognizing both energy use and the higher demand summer season.

**F. Allocation of Customer Service**

**Q. HOW DOES AE'S COST OF SERVICE STUDY ALLOCATE UNCOLLECTIBLE EXPENSE AMONG CUSTOMER CLASSES?**

A. AE directly assigns uncollectible expense based upon bad debt experience during 2014 for each customer class.

**Q. DO YOU AGREE WITH DIRECT ASSIGNMENT OF UNCOLLECTIBLE EXPENSE?**

A. No. A more reasonable method is to allocate uncollectible expense in proportion to a revenue requirement allocation factor, sometimes called a "revenue allocation." I agree with the order of the Texas Public Utility Commission on this issue in Entergy Docket No. 16705. The order in Docket No. 16705 succinctly explained the reasoning for rejecting the direct assignment proposed by Entergy, in favor of a revenue allocation:

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<sup>58</sup> *Application of Center Point Electric Delivery for Rate Increase*, Docket No. 38339, Order on Rehearing at 10: "CenterPoint's rate design expert testified that CenterPoint has already assigned non-minimum plant transformer investment based on a study utilizing energy usage by the rate classes using the transformers. The Commission finds that CenterPoint's proposal appropriately assigns these costs."

1 Just as it may seem unfair to have the industrial customers absorb  
2 the bad debts of a few individuals, it is just as unfair to have the  
3 great majority of dutiful residential ratepayers pay those debts.  
4 The passing on of such costs to others is generally factored into the  
5 cost of doing business. It is a cost that is better absorbed by the  
6 many. Therefore, uncollectible expense should be allocated at  
7 both the jurisdictional and class levels on the basis of jurisdictional  
8 and class operating revenues.<sup>59</sup>

9 As recognized in the finding of fact quoted above, the Texas PUC has treated  
10 uncollectibles as a social cost that must be absorbed on an equitable basis across classes,  
11 because the cost causers are no longer on the system. Direct assignment of the cost does  
12 not allocate the expense to cost causers, because the non-payers, by definition, are not  
13 paying customers.

14 **Q. IS THE ENTERGY DECISION CITED ABOVE CONSISTENT WITH TEXAS**  
15 **PUC PRECEDENT FOR INTEGRATED ELECTRIC UTILITIES?**

16 A. Yes. Based upon my experience, the Texas Commission's use of a revenue allocation for  
17 uncollectible is one of the most consistent allocation practices approved or ordered by the  
18 Commission over the past 25 years.<sup>60</sup> The PUC Staff was the principal advocate of this  
19 practice during most of that period. Although the nature of uncollectible expense is  
20 somewhat different in a retail competition environment, most unbundled TDUs in Texas

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<sup>59</sup> *Application of Entergy Gulf States, Inc. for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Underrecovered Fuel Costs*, Docket No. 16705, Second Order on Rehearing at Finding of Fact No. 231 (Oct. 14, 1998).

<sup>60</sup> For example, see *Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 9945, 18 P.U.C. BULL. 9 (Feb. 1992); *Application of Houston Lighting & Power Company for Authority to Change Rates*, Docket No. 6765, 13 P.U.C. BULL. 1 (Nov. 1986); *Application of Gulf States Utilities Company for Authority to Change Rates*, Docket No. 7195, 14 P.U.C. BULL. 1943, 2425 (1989) (May 1988); *Application of Texas Utilities Electric Company for Authority to Change Rates*, Docket No. 11735, Order on Rehearing, Finding of Fact No. 162 (Apr. 20, 1994).

1 allocate uncollectible expense on a revenue basis. The Texas PUC confirmed the  
2 precedent this year. Although both the PUC Staff witness and an industrial witness  
3 recommended direct assignment in the Southwestern Public Service Co. case, the  
4 pending order in that case adopts a revenue allocation, based on the following findings:

5 SPS reasonably allocated Uncollectible Account expense in FERC  
6 Account 904 on the basis of present base rate sales by class.

7 Uncollectible expenses are caused by non-paying customers, and  
8 the current customers in a particular class are not the cause of  
9 uncollectible expense created by other members of that class.<sup>61</sup>

10 **Q. IS DIRECT ASSIGNMENT ADEQUATE TO REFLECT THE COMPANY'S**  
11 **EXPOSURE ON A CLASS BASIS?**

12 A. Probably not. If one accepts the direct assignment concept, the class allocations should  
13 reflect the future risk exposure posed by each customer class. The direct assignments  
14 tend to be based on experience over a relatively short period of time. The magnitude of  
15 the uncollectible expense in a given period is affected not only by the frequency of  
16 customer accounts which are written off during a period, but also by the amount of  
17 revenue billing attributable to each particular type of customer. For example, the bad  
18 debt risk for a class with a small number of customers of varying sizes may not be  
19 adequately measured over a short duration period. In addition, the *potential* for  
20 significant impact from individual large accounts should be considered. For instance, if  
21 an industrial or large business customer goes out of business due to bankruptcy, that  
22 individual default would result in a disproportionate increase in the amount of

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<sup>61</sup> *Application of Southwestern Public Service Co. for Authority to Change Rates*, Docket No. 43695, Order, FOF 310 and 311.

1 uncollectible expense. This event is likely a low probability/high consequence exposure.  
2 Although the event may not occur in the specific one, or two year period, the allocation  
3 of an uncollectible allowance should reflect the broader exposure if a very large customer  
4 defaults. For example, although no transmission voltage customers were assigned  
5 uncollectible expense based on 2014 experience, at least one transmission voltage  
6 customer has filed bankruptcy since 2012.<sup>62</sup> The cost of service study assigned no  
7 uncollectible cost to Secondary >300 kW (due to lack of information).<sup>63</sup> AE is aware of  
8 27 bankruptcies since 2012 in the Secondary >50 kW category, but is unable to determine  
9 whether any of the bankruptcies involved customers greater than 300 kW.<sup>64</sup> The more  
10 reasonable solution is to allocate uncollectible expense as a cost of doing business which  
11 should be spread proportionately to all customer classes.

12 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.**

13 A. AE's proposed direct assignment of uncollectible expense should be rejected. Instead,  
14 uncollectibles should be allocated on the basis of revenues (Rev Req allocation).

15 **G. Allocation of Meters and Services**

16 **Q. HOW ARE METERS ALLOCATED IN THE AE CCOS STUDY?**

17 A. AE develops a weighted customer allocation which reflects the cost of different meter  
18 sizes installed by customer class. This method is appropriate and standard, as far as it

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<sup>62</sup> AE Response to ICA 2-29.

<sup>63</sup> Inadequate secondary >50 kW uncollectible records constitute another flaw in AE's direct assignment. The records did not permit identification of uncollectible based on the proposed Secondary class configuration. As a result, AE subjectively chose to assign all of the Sec >50 kW uncollectible expense to <300 kW customers, assuming that the cost belonged to the class with the most customers.

<sup>64</sup> Ibidem.

1 pertains to the traditional meter function. However, AE has been aggressive in the  
2 sophistication of the meters it deploys, and the implication of these advancements is that  
3 substantial meter investment cost has been expended to access meter functions which  
4 transcend the standard billing and collection measurement role. The allocation method  
5 for meter investment should take into account the incremental cost of enabling other  
6 functions.

7 **Q. WHAT IS THE INCREMENTAL COST OF INSTALLING SMART METERS**  
8 **OVER ELECTRO-MECHANICAL METERS?**

9 A. The cost of a manual residential meter is \$48 and the cost of a comparable smart meter is  
10 \$190. Thus, the manual meter is approximately 20% of the cost of the smart meter. The  
11 remaining 80% of the smart meter cost represents investment incurred for functions  
12 which cannot be performed by a manual meter.

13 **Q. WHAT ADDITIONAL FUNCTIONS CAN BE ACCESSED AS A RESULT OF**  
14 **THE INCREMENTAL INVESTMENT FOR SMART METERS?**

15 A. A significant benefit arises from reductions in meter reading cost. Additional utility  
16 benefits involve the reliability function, enabling improved outage detection and system  
17 wide recovery.<sup>65</sup> Societal benefits arise from direct load control, demand response, and  
18 integration of distributed generation, which reduces peak demand, thereby applying  
19 downward pressure on energy prices in spot markets and reducing the need for new

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<sup>65</sup> Costs and Benefits of Smart Meters for Residential Customers, July 2011, Edison Foundation Institute  
for Energy Efficiency, White Paper at  
5.[http://www.edisonfoundation.net/iei/Documents/IEE\\_BenefitsofSmartMeters\\_Final.pdf](http://www.edisonfoundation.net/iei/Documents/IEE_BenefitsofSmartMeters_Final.pdf).



1 generation.<sup>66</sup> Customers benefits arise from enhanced ability to manage energy costs,  
2 shift loads, and identify wasteful uses of electricity.<sup>67</sup> AE recognizes most of these  
3 functions and continues to activate meter functions which enable these benefits.<sup>68</sup>

4 **Q. HOW DID YOU RELATE THESE INCREMENTAL COSTS AND FUNCTIONS**  
5 **TO THE CLASS ALLOCATOR?**

6 A. The avoidance of meter reading expense constitutes as much as one-half of the net  
7 present value benefit of smart meter investment,<sup>69</sup> and this proportion of the incremental  
8 cost can be allocated on the weighted customer basis. However, the remainder of the  
9 incremental cost pertains to demand-side management, avoided generation cost, and  
10 reliability. Production demand is a reasonable measure for these functions. Therefore,  
11 my recommendation is to allocate meter investment on a 60% weighted customer and  
12 40% production demand basis.<sup>70</sup>

13 **Q. HOW DID AE'S CCOS STUDY CLASSIFY SERVICES?**

14 A. The Company classified the service drops as demand-related distribution. The NARUC  
15 CAM specifies that services are properly classified as customer-related. In my  
16 experience, other electric utilities treat services as customer-related. My recommendation  
17 is to change the classification of services to customer.

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<sup>66</sup> Id.

<sup>67</sup> Id.

<sup>68</sup> AE Response to AELIC Request 9-23 and 9-24.

<sup>69</sup> Costs and Benefits of Smart Meters for Residential Customers, page 31 – 34.

<sup>70</sup> The incremental investment above manual meter cost is 80% of the total meter plant. 40% of the total meter plant cost (80% X 50%) is allocated on a production demand basis.

1 **Q. WHAT IS THE EFFECT OF CHANGING THE CLASSIFICATION OF**  
2 **SERVICES?**

3 A. In AE's particular circumstances, classifying services as customer-related reduces the  
4 costs assigned to the customer function. This is because the total net services cost is  
5 negative.

6 **H. Allocation of Customer Accounts**

7 **1. Meter Reading**

8 **Q. HOW DO YOU PROPOSE TO CHANGE THE CCOS STUDY'S ALLOCATION**  
9 **OF METER READING EXPENSE?**

10 A. AE allocates meter reading expense on the basis of number of customers. My  
11 recommendation is to allocate meter reading expense on the weighted customer allocator  
12 applied to meters. Meter reading expense obviously is associated with meter investment.  
13 The weighted customer allocator reflects differences in the costs of meters among the  
14 customer classes. Larger meters tend to be associated with larger customer bills, and the  
15 utility should take greater care in verifying the accuracy of higher revenue accounts. If a  
16 problem arises in the automated reading of large customer's bill, additional time is  
17 incurred by meter readers to re-set the demand meter when they manually re-read the  
18 meter.

19 **2. 311 Expense**

20 **Q. PLEASE DISCUSS AE'S 311 CALL EXPENSE.**

21 A. The 311 call center enables Austin residents to make inquiries or notifications to city  
22 departments. Austin Energy includes \$2.38 million for this expense in A417 (General

Expense-Non Utility Operations), and functionalizes the expense to Customer. A relatively small portion of the expense is based on usage (number of call attributable to AE). Most of this expense is directly assigned to AE and supports the disaster recovery center. AE justifies the expenditure because it provides back up to AE's normal operations. This Center enables Austin Energy to operate in emergency mode due to severe storms or disaster conditions.

**Q. DO YOU AGREE WITH THE CCOS STUDY'S TREATMENT OF THIS EXPENSE?**

A. No. The primary function pertains to system reliability and maintaining continuous delivery of power. Disaster recovery presumably is focused on repairing and restoring power service. The expense is more reasonably functionalized to Distribution, because distribution facilities are most related to maintaining power delivery. Therefore, my recommendation is functionalize A417 to Distribution and to allocate the expense to classes based on distribution O&M expense.

### **3. Customer Service Accounts**

**Q. HAVE YOU PROPOSED CHANGES TO THE ALLOCATION OF ANY CUSTOMER SERVICE ACCOUNTS?**

A. Yes. I have modified the allocations of the following accounts: 908 – 910 (Customer Assistance, Informational Advertising, Miscellaneous Informational Expense, Advertising Expense, and Miscellaneous Sales Expense). Except for the portion of this expense allocated to Key Account customers, AE allocates these accounts based on number of customers by class.

1 **Q. WHAT IS INCLUDED IN THESE ACCOUNTS?**

2 A. The object of these accounts is to advise customers on the safe and efficient use of  
3 electricity, promote or retain electrical usage, or encourage conservation or  
4 environmentally beneficial activities. These costs include exhibitions, displays, and  
5 advertising designed to promote utility service. The activities can be designed to market  
6 the utility's services, promote the image of the utility, retain customers, and/or foster the  
7 safe use of the utility's services and facilities.

8 **Q. ARE THESE EXPENDITURES PROPERTY ALLOCATED ON AN**  
9 **UNWEIGHTED CUSTOMER BASIS?**

10 A. No. There is no reason to believe that the costs of achieving such general objectives will  
11 vary in proportion to the number of customers. The expenditures represent a general cost  
12 of doing business and are more properly treated as an overhead. In addition, customer  
13 assistance and information costs are incurred to direct customers to energy efficiency  
14 programs, and such programs are not otherwise allocated on a customer basis. The  
15 NARUC CAM encourages weighting of customer allocations for these accounts. For  
16 A906 – 910, the manual recommends separate analysis of actions which affect  
17 customers' usage of generation and energy. For A911 – 917, the manual states:

18 Allocation of these costs, however, should be based upon some  
19 general allocation scheme, not numbers of customers. Although  
20 these costs are incurred to influence the usage decisions of  
21 customers, they cannot properly be said to vary with the number of  
22 customers. These costs should be either directly assigned to each

customer class when data are available, or allocated based upon the overall revenue responsibility of each class.<sup>71</sup>

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ALLOCATION OF THESE ACCOUNTS?**

A. Austin Energy directly assigns 14% of these accounts to Key Account customers. My recommendation accepts the direct assignment of this portion of the accounts. However, I have developed a weighted customer allocator, instead of unweighted customers, for the remainder of the accounts. The weighted allocator for the remaining 86% of the expense is 50% class revenue requirement and 50% number of customers. This approach recognizes that the general expenses in these accounts which cannot be directly assigned should be treated, in part, as general overhead. This weighting also includes the same revenue requirement allocation applied to energy efficiency programs, thereby recognizing that some customer assistance and informational activities direct consumers to energy efficiency programs.

**I. Functionalization of Service Initiation Revenue**

**Q. WHAT IS AE'S FUNCTIONALIZATION OF THE NEW SERVICE INITIATION FEE?**

A. The new service connection fee pertains to starting new service and reconnecting a customer who has been disconnected. AE classifies the fee as distribution-related because "the service is associated with the distribution of power to the customer." However, contrary to the implication of such a rationale, the fee does not recover the

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<sup>71</sup> NARUC CAM at 104.

1 incremental facility costs of new services and new meters.<sup>72</sup> This fee is for ordering the  
2 initiation of new service.

3 **Q. DO YOU AGREE WITH AE'S FUNCTIONALIZATION OF THIS REVENUE**  
4 **ITEM?**

5 A. No. The revenues are more reasonably identified as customer-related. Service initiation  
6 pertains to customer access, and customer access is part of the customer function.  
7 Service initiation frequency is more likely to vary with number of customers than  
8 distribution demands.

9 **J. Summary of Results**

10 **Q. DO YOUR PROPOSED CHANGES TO THE CCOS STUDY SIGNIFICANTLY**  
11 **ALTER THE INTERCLASS RELATIONSHIPS BETWEEN RESIDENTIAL AND**  
12 **SMALL COMMERCIAL CLASSES AND THE OTHER CUSTOMER CLASSES?**

13 A. Yes. Austin Energy claims that the residential and Sec.<10 kW classes currently receive  
14 significant subsidies from other classes. As a result, AE proposes that the residential and  
15 small commercial classes should not be assigned any of the \$17 million base revenue  
16 reduction. In addition, AE suggests that the two classes should transition in the direction  
17 of cost in future rate requests. However, without any of the revenue requirement  
18 reductions proposed in Sec. III and including my CCOS changes, current total revenues  
19 for residential is approximately at cost (within 0.3%) and small commercial is slightly  
20 above cost. This casts considerable doubt on AE's claim that a large subsidy to the  
21 residential and small commercial class is embedded in current rates. This is shown below

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<sup>72</sup> AE Response to ICA Request 7-3.

corrected. Given the minimal difference from its fully allocated cost, the residential class is essentially at cost. Schedule CJ-3 shows the comparable results for all classes.

ICA CCOS Study		
Above/(Below) Cost		
	Residential	Sec.<10 kW
ICA Position	\$ 11,409,407	\$ 687,049
Indicated Incr./(Decr.)	-4.40%	-3.60%
Sch. G10 As Filed	\$ (53,411,041)	\$ (783,742)
Indicated Incr./(Decr.)	20.80%	4.10%

**Q. WHAT ARE THE BASE REVENUE RESULTS USING BOTH ICA'S REVENUE REQUIREMENT RECOMMENDATION AND CCOS ALLOCATION?**

**A.** At current base revenues, both the residential and Sec. <10 kW classes are fully above cost and deserving of base revenue reductions. The results for the two classes are shown below [\(corrected\)](#). Schedule CJ-4 shows the comparable results for all classes.

	ICA CCOS Study	
	Above/(Below) Cost	
	Residential	Sec.<10 kW
ICA Position	\$ (7,809,736)	\$ (547,196)
Indicated Incr./(Decr.)	-3.03%	-2.87%
Sch. G10 As Filed	\$ 53,411,041	\$ 783,742
Indicated Incr./(Decr.)	20.80%	4.10%

**Q. HAVE YOU INCLUDED INFORMATION ON THE SPREADSHEET REFERENCES FOR THE MODIFICATIONS YOU MADE TO THE AE CCOS MODEL?**

A. Yes. Schedule CJ-5 provides the lines, columns, and tab labels for the changes that were made, pursuant to the rules for filing the recommendation.

## **V. ALLOCATION OF REVENUE REDUCTIONS TO CLASSES**

**Q. WHAT IS THE CLASS REVENUE DISTRIBUTION ISSUE IN THIS CASE?**

A. Class revenue distribution involves the assignment or allocation of a system revenue increase or decrease to rate classes. The CCOS results provide useful information which is considered in addition to non-cost principles. This case pertains to the allocation of a system revenue decrease. Based on ICA's revenue requirement adjustments, ICA proposes to allocate [\\$38.9](#) million of base revenue decreases among customer classes.



1   **Q.    WHAT IS THE APPROPRIATE ROLE OF THE EMBEDDED CCOS STUDY**  
2   **RESULTS IN DETERMINING CLASS REVENUE INCREASES?**

3   A.    The CCOS provides useful information for developing the class revenue increases, but it  
4       should not be the sole consideration.  Non-cost considerations are appropriate in  
5       mitigating pure CCOS results.  This principle has been recognized in longstanding  
6       regulatory texts, such as Dr. James Bonbright's seminal *Principles of Public Utility*  
7       *Rates*.<sup>73</sup>

8           CCOS studies are imprecise instruments.  The studies will allocate costs to a  
9       multiple decimal point level, but this may provide a false sense of security about the  
10      accuracy of the studies.  This conclusion is based on two general reservations regarding  
11      embedded CCOS studies.  First, some of the costs are classified and allocated on a  
12      disputable causal basis and subjective judgment enters into the selection and development  
13      of allocation methods.  The CCOS results may be quite sensitive to alternative  
14      classification or allocation decisions which are within the range of reasonable choices.  
15      As a result, it may be more appropriate to characterize the CCOS in the form of a range  
16      of acceptable rates of return instead of a single point estimate.  For instance, in the 2012  
17      rate review, AE took the position that class revenue changes within 5% of the CCOS  
18      study result are reasonable and justified.  Second, CCOS studies are a static snapshot of  
19      the dynamic relationship between supply and demand.  Both costs and class usage  
20      characteristics will change over various time periods.  For these reasons, some degree of  
21      judgment may be appropriate in applying the CCOS study to class revenue increases.

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<sup>73</sup>   Bonbright, *Principles of Public Utility Rates* at 29, (Columbia Press 1961).

1 “Cost based rates” are best viewed as representing a reasonable band around the CCOS  
2 results, rather than exact price points. Furthermore, CCOS studies which do not  
3 recognize the differences in risk associated with customer classes should be utilized  
4 cautiously.

5 **Q. PLEASE DISCUSS AE’S REVENUE DECREASE PROPOSAL.**

6 A. AE proposes an approximate \$17 million base revenue reduction. Based on the CCOS  
7 results, AE proposes assigning no revenue decrease to the Residential and Sec. <10 kW  
8 and allocates the remainder of the decrease to commercial classes which are above cost.  
9 ICA disagrees with this proposal in two respects. First, the total revenue reduction  
10 should be approximately \$39 million. Second, the CCOS study allocation adjustments  
11 presented in Sec. IV produce markedly different results regarding the relative cost  
12 positions of classes. The ICA CCOS results do not support AE’s proposal to assign no  
13 revenue decrease to the Residential and Sec. <10 kW classes. The current base revenues  
14 for those two classes exceed the classes’ cost of service.

15 **Q. WHAT GENERAL APPROACH GUIDED ICA’S CLASS REVENUE**  
16 **REDUCTION ALLOCATION?**

17 A. ICA contends that the revenue decrease should be distributed broadly among the  
18 customer classes, rather than precisely linked to specific CCOS results. AE is publicly  
19 owned, and excess revenues should be broadly shared among different types of  
20 customers. I used the CCOS study to determine the customer classes which are far below  
21 cost—in this case, the lighting classes. For those classes, my proposal leaves the base  
22 revenues unchanged. In addition, I used the CCOS study result to assign a base revenue

1 increase to Transmission >20 MW, 85% LF. AE's rate filing explains that this class'  
2 revenues are designed to be set at cost. The customer in this class pays a fixed contract  
3 and will be unaffected. But setting the revenues at cost ensures that other customers are  
4 not subsidizing the contract rate. Incorporating an approximate \$2 million base revenue  
5 increase for this class produces a \$41 million revenue decrease to be distributed among  
6 the remaining classes.

7 **Q. HOW DO YOU PROPOSE TO ALLOCATE THE \$41.8 MILLION REVENUE**  
8 **REDUCTION AMONG THE REMAINING CLASSES?**

9 A. My proposal is to allocate the revenue decrease on the basis of class shares of kWh  
10 consumption. I view this as a compromise allocation. The kWh methodology produces a  
11 more favorable revenue reduction for higher load factor customer classes than an equal  
12 percentage revenue decrease. The resulting allocation will be more similar to AE's  
13 proposal, inasmuch as AE's CCOS study produces more favorable results for high load  
14 factor customer classes. Schedule CJ-6 sets out the proposed allocation of the revenue  
15 decrease among customer classes. If the IHE approves a different revenue reduction than  
16 ICA's proposal, the same allocation method should be used.

17 **VI. RATE DESIGN**

18 **A. Residential Rate Design**

19 **Q. WHAT MATTERS WILL YOU ADDRESS RELATED TO AE'S PROPOSED**  
20 **RESIDENTIAL RATE DESIGN?**

21 A. The principal components of the residential rate design pertain to the fixed customer  
22 charge, summer/winter differential, and the tiered energy rate. Furthermore, ICA will

1 address future potential changes, as well as the AE proposal for the rate design requested  
2 in this case. The AE rate filing discusses the utility's views regarding the direction of  
3 future potential changes.

4 **1. Customer Charge**

5 **Q. WHAT IS AE'S PROPOSAL REGARDING THE RESIDENTIAL CUSTOMER**  
6 **CHARGE?**

7 A. AE proposes the no change to the residential customer charge, which is \$10 per month.  
8 ICA agrees that the current customer charge should remain unchanged.

9 **Q. DO YOU AGREE WITH AE'S OVERALL POSITION WITH RESPECT TO THE**  
10 **RESIDENTIAL CUSTOMER CHARGE?**

11 A. No. AE contends that the current residential customer charge is substantially below cost,  
12 and suggests that the level of customer charge should be increased in the future. ICA  
13 disagrees with both contentions. AE's position is not surprising, because it is consistent  
14 with pricing strategies commonly espoused by utilities. Raising customer charge levels  
15 creates a constant revenue stream, thereby shifting risk to customers. Furthermore, this  
16 pricing strategy frequently involves shifting cost recovery to the least elastic<sup>74</sup> component  
17 of rates; customers have no means of controlling the size of their bill in response to a  
18 customer charge increase---other than leaving the system. While AE's interest in revenue  
19 stability is understandable, a pricing strategy based on raising fixed monthly charges is  
20 not consistent with the interests of customers. The only economic function of a customer

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<sup>74</sup> "Elasticity" is an economic term for the change in customer usage which occurs in response to changes in price.

1 charge is to ration access to the utility system. However, this access rationing role is not  
2 consistent with public interest rate regulation. Electric utility service is considered a  
3 human necessity in modern society, and public interest regulation encourages universal  
4 utility service. The only rate components which provide useful economic price signals  
5 are usage charges. In the case of residential rates, minimizing the customer charge moves  
6 cost recovery to energy charges, which provide a useful conservation price signal. For  
7 this reason, maintaining a low customer charge enhances the customer's ability to control  
8 the size of the electric bill.

9 **Q. HOW DOES AE'S RESIDENTIAL CUSTOMER CHARGE COMPARE TO THE**  
10 **CUSTOMER CHARGES OF OTHER BUNDLED ELECTRIC UTILITIES**  
11 **REGUATED BY THE TEXAS PUC?**

12 A. AE's \$10 residential customer charge is higher than any of the other bundled electric  
13 utilities: \$6.00 for ETI; \$5.00 for El Paso Electric Co.; \$8.00 for SWEPCO; and \$9.50 for  
14 Southwestern Public Service Co.

15 **Q. DO YOU AGREE WITH AE'S CLAIM THAT THE COST-BASED**  
16 **RESIDENTIAL CUSTOMER CHARGE IS \$22 PER MONTH?**

17 A. No. This position is based on a fully loaded customer charge derived from the CCOS  
18 Study. Given its nominal pricing function, the customer charge should only recover costs  
19 which vary directly with the number of customers. Generally, the costs which vary  
20 directly with customer count consist of the direct costs of meters, service lines, meter  
21 reading, and customer billing. Although the AE's CCOS study shows a customer unit  
22 cost higher than its request, the CCOS includes costs in the customer unit price which are

1       only indirectly associated with customers. The CCOS calculated customer unit cost  
2       includes a portion of general overhead costs, such as A&G expense, which do not vary  
3       with changes in the number of customers. However, even if the fully loaded customer  
4       charge calculation is accepted, ICA's CCOS indicates a cost of \$14.35, which is  
5       significantly closer to the current \$10 charge than AE's claimed cost.

6       **Q. HAVE YOU ESTIMATED A RESIDENTIAL CUSTOMER CHARGE LEVEL**  
7       **FOR AE WHICH IS DIRECTLY RELATED TO THE NUMBER OF**  
8       **CUSTOMERS?**

9       A. Yes. My estimate of the customer charge directly related to the number of customers  
10       results in a \$9.35 monthly charge. Since the existing customer charge is \$10, the current  
11       customer charge is more than compensatory. The calculation includes costs for meters,  
12       services, meter reading, customer accounting, and customer service, but excludes  
13       uncollectibles, General Fund Transfer, and A&G expense embedded in the customer  
14       expense amounts. GFT is a return component which should not be recovered through the  
15       expense elements of the customer charge. Therefore, I estimated the removal of GFT and  
16       A&G from the components other than meters and services. The calculation is consistent  
17       with the historic Commission practice for evaluating the customer charge level of  
18       bundled electric utilities.<sup>75</sup> The calculation is set out on Schedule CJ-7.

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<sup>75</sup> See for example *Application of Houston Lighting & Power Company*, Docket No. 8425, PFD at 264, 16 P.U.C. BULL. 2199 and 2488 (June 20, 1990).

1   **Q.     GIVEN AE’S VIEW REGARDING FIXED CHARGES, SHOULD AE CONSIDER**  
2       **RESIDENTIAL DEMAND CHARGES IN THE FUTURE?**

3   A.   No. Demand charges, which establish monthly charges based on an hour or less of  
4       maximum usage, are not well suited for residential rate design. Demand charges have  
5       caused considerable bill impacts and confusion for small commercial users who were  
6       moved off of energy rate tariffs; the impact and negative reaction is likely be multiplied  
7       many times over for residential customers. The only TDU in Texas which attempted to  
8       implement mandatory residential demand charges (McAllen Division of Sharyland) did  
9       so only briefly because of the major bill impacts and confusion. Optional Time of Day  
10      rates are a better alternative in the residential class.

11               **2.   Residential Tiered Energy Charges**

12   **Q.     WHAT IS AE’S RATE STRUCTURE FOR COLLECTING ENERGY CHARGES?**

13   A.   AE has an inverted block rate structure in the residential class. An inverted block means  
14       that each successive block or tier of energy usage has a higher energy rate. AE has five  
15       tiers for inside city customers and three tiers for outside city customers. The advantage  
16       of an inverted block structure is that it provides a strong price signal for conserving  
17       energy. In addition, the price signal may produce environmental benefits. A steeper  
18       inverted block structure can be accomplished with more tiers of usage, and AE has  
19       exploited this characteristic with five tiers for inside city customers. The cost basis for an  
20       inverted block arises when long run marginal costs are higher than embedded costs;  
21       under those conditions, increased usage inflates the future costs per kW or kWh to be  
22       collected from all customers.

1 **Q. DO YOU AGREE WITH AE'S ANALYSIS THAT HIGH USAGE TIERS ARE**  
2 **PAYING ABOVE COST WHILE LOW USAGE TIERS ARE PAYING BELOW**  
3 **COST?**

4 A. Not necessarily. This appears to be an attempt to use the CCOS study to define whether  
5 customers of various usage levels are above or below cost. In my opinion, this is not an  
6 appropriate use of the CCOS study. The CCOS allocates costs to customer classes, not to  
7 individual customers or customers at various tier levels. The allocation factors for  
8 assigning costs to classes are not the same measures as the rate components within the  
9 rate structure. In my view, the attempt to graft CCOS results to individual customer  
10 usage levels can produce serious inaccuracies. In essence, an assumption is made that  
11 energy use has a strict linear relationship with the various demand allocators in the  
12 CCOS, which may not be correct. Moreover, this type of analysis may ignore higher  
13 summer load factors in low use tiers which include customers without air conditioning or  
14 other appliances. Moreover, a more appropriate cost analysis for rate design purposes  
15 would involve marginal costs rather than embedded costs, because rate design focuses on  
16 the appropriate price signals.

17 **Q. WHAT IS AE'S PROPOSAL WITH RESPECT TO THE FIVE TIERED RATE**  
18 **STRUCTURE?**

19 A. AE flattens the tier structure somewhat. This involves higher rates in the first tier and  
20 lower rates in higher tiers. AE's objective is to increase revenue stability from the  
21 inverted block structure. The bill impact by customer usage is illustrated on Schedule H-  
22 3. Up to 750 kWh, the average customer bill will increase 4% - 7%. In the 750 kWh –



1 1000 kWh usage category, the average bill impact declines slightly, and the decrease  
2 grows to -2.5% in the 1750 – 2000 kWh group. The average percentage decrease for the  
3 highest usage levels is just above -1%.

4 **Q. DO YOU AGREE WITH THIS APPROACH?**

5 A. I don't disagree with the objective of producing more revenue stability in the rate  
6 structure. The utility's revenue collections will be particularly sensitive to weather  
7 conditions with steeper tiers. The five tier structure also can produce volatile results for  
8 customers too. During an abnormally hot summer, customers may unknowingly be  
9 pushed into a higher tier than they are accustomed, which could produce rate shock.  
10 However, AE's approach to flattening the rate structure is problematic, because it  
11 produces bill increases in the first tier of usage. Many of these low use customers have  
12 little room to further reduce consumption, and may be unable to lower their bills in  
13 response to the higher rate.

14 **Q. DO YOU HAVE AN ALTERNATIVE APPROACH?**

15 A. The ICA's revenue reduction recommendation assigns part of the system base revenue  
16 reduction to the residential class. In addition, the ICA's proposed revenue reduction is  
17 more than twice the size proposed by AE. A portion of the residential share of the base  
18 revenue reduction can be used to fund the changes to the rate structure without increasing  
19 rates for the lowest tier. Thus, AE could achieve its desired reduction in the steepness of  
20 the tier structure, but also maintain the basic rate levels for the first tier. After using part  
21 of the base revenue reduction for this change, any remaining residential base revenue  
22 reduction amount should be used to reduce all tiers equally.

1 **Q. SHOULD AE MAKE ANY CHANGES IN THE NUMBER OF TIERS FOR**  
2 **INSIDE CITY CUSTOMERS?**

3 A. This is an issue which AE should study before its next rate case. However, changing the  
4 number of tiers in this case would be overly disruptive and could produce unintended  
5 consequences. However, there are potential advantages to reducing the number of tiers to  
6 three or four. These advantages include: less revenue volatility, fewer instances of  
7 customers unintentionally landing in a higher tier due to abnormal weather, and a less  
8 complicated rate design which can be more easily understood. Additionally, if AE  
9 considers the possibility of unifying the inside/outside city rate structures in the future, it  
10 may be easier to do so with fewer tiers. The scope of such a study should include an  
11 analysis of bill impacts for various options, as well as a more thorough analysis of the  
12 utility's long run marginal costs relative to embedded costs. An analysis of long run  
13 marginal costs would provide better support for various tier options.

14 **3. Summer / Winter Differential**

15 **Q. WHAT IS AE'S PROPOSAL WITH RESPECT TO THE SUMMER/WINTER**  
16 **BASE RATE DIFFERENTIAL?**

17 A. AE proposes to eliminate the base rate summer/winter differential, which lowers rates in  
18 the winter. In addition, AE proposes to include, for the first time, a summer/winter  
19 differential in the power supply adjustment (PSA).

20 **Q. DO YOU OBJECT TO THIS PROPOSAL?**

21 A. No. High summer bills produce the most difficulties for household budgets, and  
22 potentially the elimination of the base rate summer/winter [differential](#) will moderate bill

1 impacts and reduce customers' need for deferred payment plans. To some extent, this  
2 can be viewed as a trade-off between putting the summer/winter differential in the PSA  
3 versus base rates. From a costing standpoint, the differential is only related to the  
4 production function.<sup>76</sup> Some level of summer/winter differential is justified, but applying  
5 the differential to both the PSA and base rates will likely result in an excessive summer  
6 rate. Applying the differential only to the PSA, based on ERCOT price differentials,  
7 provides a stronger connection to documented seasonal cost differences and is more  
8 consistent with the principles behind the 12 CP and BIP production demand allocation  
9 methods. It should be noted that the summer/winter differential is likely to be more  
10 moderate when applied to the PSA rather than the base rates.

11 **B. Small Commercial Rate Design**

12 **Q. WHICH CLASSES CONTAIN SMALL COMMERCIAL CUSTOMERS?**

13 A. The Sec. <10 kW (S1) and the lower end of the Sec. 10 – 300 kW (S2) classes contain  
14 customers who can generally be characterized as small commercial. The S1 class has a  
15 customer charge / energy charge rate structure. The S2 class also pays a demand charge.

16 **Q. DO YOU OBJECT TO THE RATE DESIGN APPLIED BY AE TO THOSE**  
17 **CLASSES?**

18 A. Generally, no. As I will discuss in the next sub-section, I object to AE's proposal to  
19 terminate the HOW rate rider for these classes. For most small commercial customers in

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<sup>76</sup> For instance, for unbundled electric utilities, the Texas PUC does not permit a summer/winter differential in delivery rates. Bundled utilities are permitted to apply such a differential to base rates though.

1 the S2 class, the rate structure impacts are minor in comparison to the effect of the base  
2 revenue reduction assigned to the class.

3 **Q. HAS AE PROPOSED ANY BILLING LIMIT PROVISIONS WHICH ARE**  
4 **NOTABLE FOR SMALL COMMERCIAL CUSTOMERS?**

5 A. Yes. AE proposes a 20% load factor floor for the S2 class. Since low load factor  
6 customers in the S2 class tend to be smaller sized customers, this will affect small  
7 commercial customers. Load factor is the ratio of a customer's average annual demand  
8 to the customer's maximum demand (the basis for demand charge billing). Customers  
9 who concentrate their energy use in a small number of hours will exhibit a low load  
10 factor and incur a demand charge that is high relative to total usage. If a S2 customer  
11 exhibits a load factor below 20%, the new floor provision will impute a lower level of  
12 billing demand. I agree with this new provision, because it will mitigate rate shock  
13 among certain types of small commercial customers. This provision is analogous to a  
14 low load factor mitigation tariff used by Southwestern Public Service Co., commonly  
15 called "the Rule of 80." In my view, special rates for customers with exceptionally low  
16 load factors are justified because the customer's unusual load characteristics are not well  
17 suited for demand charge billing. I would also note that the 20% load factor floor also  
18 will benefit some HOW customers.

1 **Q. DO YOU HAVE ANY CONCERNS ABOUT HOW AUSTIN ENERGY WILL**  
2 **APPLY ITS RATE DESIGN PRINCIPLES TO SMALL COMMERCIAL**  
3 **CUSTOMERS IN THE FUTURE?**

4 A. Yes. AE emphasizes adherence to strict fixed/variable pricing and states its desire to  
5 pursue pricing which promotes high load factor. According to AE, high load factor is  
6 “efficient.” My concern is that AE will continue to increase the customer charge for S1  
7 and S2 in the future and shift more costs from energy rates to the demand charge when  
8 S2 rates are changed again.

9 **Q. DO YOU HAVE ANY COMMENTS RELATED TO AE’S POSITION THAT**  
10 **PROMOTING HIGH LOAD FACTOR IS “EFFICIENT?”**

11 A. Yes. The pricing policy should distinguish between different types of efficiency. Load  
12 factor promotion is associated with static engineering efficiency, and typically is a  
13 response to excess generating capacity. Economic efficiency, on the other hand, is more  
14 focused on the long run impact of prices on the utility’s marginal costs. Rather than  
15 simply pursuing higher load factors, AE’s pricing objective should balance both types of  
16 efficiency. In my opinion, AE should be cautious in strictly adhering to the objective of  
17 shifting costs from variable rates to demand charges. Over the long run, pursuit of higher  
18 load factors may lead to higher costs and economically inefficient behavior. Higher  
19 system load factors may shift the generation capacity expansion path toward higher  
20 capital cost baseload generation. In addition, increased system load factor may create  
21 upward pressure on the required generation reserve margin necessary to achieve a given  
22 level of reliability. Finally, for some customers, the maximum demand as measured by

1 the demand charge is poorly related to the coincident demands which are relevant to  
2 system load factor. Furthermore, aside from the efficiency criteria, promotion of high  
3 load factor may conflict with Austin's objective of reducing environmental emissions.  
4 Since load factor promotion generally leads to more megawatt hours (Mwh) of  
5 generation, the environmental effect is likely to be negative.

6 **Q. DO YOU FAVOR INCREASING THE S1 AND S2 CUSTOMER CHARGES IN**  
7 **THE NEXT RATE CASE?**

8 A. No. AE should avoid raising the small commercial customer charge, if possible.  
9 Similarly, AE should refrain from shifting costs from energy rates to the demand charge  
10 in the next rate case.

11 **C. Houses of Worship (HOW) Rate Design**

12 **Q. PLEASE DESCRIBE THE CURRENT HOUSE OF WORSHIP (HOW) RATE**  
13 **AND THE "TRANSITION" FROM THE LAST RATE CASE.**

14 A. Austin Energy proposes to end the current discount to Group Religious Worship  
15 Accounts, also referred to as "Houses of Worship" or HOWs. Austin Energy had  
16 proposed to end the discount in the 2012 rate case, moving HOWs into the commercial  
17 rate class. The City Council approved transitioning away from the discount by  
18 establishing a transition maximum charge to mitigate rate shock"<sup>77</sup>, currently set at  
19 13.015 cents per kWh. The Council also closed the discount rate to new customers, but  
20 later reversed that policy, allowing new facilities to take advantage of the rate.<sup>78</sup> In

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<sup>77</sup> Tariff Package at 6.8.3, Bates 174.

<sup>78</sup> Tariff Package at Bate 174, referring to Ordinance No. 20130909-003.

1 addition, weekend hours are not considered when determining billed peak demand.<sup>79</sup>

2 Austin Energy also states that staff worked “proactively” with group religious worship  
3 accounts to offer advice on energy management and to access energy efficiency services.

4 **Q. WHAT IS AUSTIN ENERGY’S PROPOSAL WITH REGARD TO THE HOW**  
5 **RATE?**

6 A. Austin Energy proposes to end the transition period and fully move HOW into the  
7 commercial rate classes. This means that the 13.015 cents per kWh would no longer  
8 apply and demand would be measured at peak usage.<sup>80</sup>

9 **Q. WHAT IS THE STATUS OF THE EL PASO ELECTRIC HOUSE OF WORSHIP**  
10 **RATE?**

11 A. In the Tariff Package Austin Energy states that the Public Utility Commission of Texas  
12 has largely discontinued HOW rates. In the 2012 rate case Austin Energy cited El Paso  
13 Electric (EPE) as precedent. In the 2009 EPE rate case, churches were caught in the  
14 middle of a rate class restructuring, losing their separate energy only rate. After the rates  
15 went into effect, churches faced major bill impacts, and the Texas PUC subsequently  
16 ordered a transition rate, which is still in effect. EPE has a new rate case (Docket No.  
17 44491) pending now, and the utility is proposing to extend the transition rate for HOW,  
18 phasing it out over a period of years. The current EPE transition rate is similar to the  
19 HOW cap for Austin Energy. The EPE proposal is to have a cap of \$0.1325/kwh until its  
20 next rate case, then a cap of \$0.1525 for 12 months, then a cap of \$0.1725 for 12 months,

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<sup>79</sup> <http://austinenergy.com/wps/wcm/connect/ab6d045c-643e-4c16-921f-c76fa0fee2bf/FY2016aeElectricRateSchedule.pdf?MOD=AJPERES>.

<sup>80</sup> See Tariff Package at 6.8.3 and Bethany Church 1-5.

1 and finally no cap. The length of the new transition period will depend on the decision in  
2 the pending rate case. However, realistically, the Commission will consider whether to  
3 extend the transition period in the following rate case, if necessary. As stated by EPE's  
4 rate design witness, James Schictl, "As a practical matter, EPE and other parties will have  
5 another opportunity to address the rate limiter in EPE's 2017 rate case. In addition, EPE  
6 fully absorbs the cost of the limiter..."<sup>81</sup>

7 **Q. WHAT IS THE EFFECT OF AUSTIN ENERGY'S PROPOSAL TO END THE**  
8 **HOW TRANSITION?**

9 A. Houses of Worship in Austin will pay approximately \$1 million more in rates<sup>82</sup> under  
10 Austin Energy's proposal. The impact on individual Houses of Worship is not uniform.  
11 Some will see little change under the new rates, some will even benefit due to other rate  
12 changes proposed by AE. However, many smaller churches, particularly those in the S1  
13 class and those at the lower end of S2 eligibility threshold will experience significant bill  
14 increases that I would describe as rate shock.<sup>83</sup> A variety of factors coincide in this rate  
15 request to create rate shock conditions; these include loss of the discount, loss of the  
16 weekday-only demand measurement, AE's effort to place greater cost recovery on fixed  
17 charges; and expansion of the size of the S2 class from 50 kW to 300 kW as the upper  
18 limit.

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<sup>81</sup> Rebuttal Testimony of James Schictl at 82, Docket No 44941.

<sup>82</sup> Bethany Church 2-2, ICA 1-9, ICA 3-26, Attachment 1.

<sup>83</sup> ICA 3-26 Attachment 1 shows the value of the lost discount compared to bills.



1   **Q.    IS THE CONVERSION OF MANY CHURCHES FROM ENERGY CHARGES TO**  
2   **DEMAND CHARGES A MAJOR CAUSE OF RATE PROBLEMS?**

3   A.    Yes.  For instance, some of the churches are principally off-peak, and have low load  
4       factors.  For example, some churches may only use power for lights and heating/air  
5       conditioning only for a brief number of hours on the weekend, but the demand charge  
6       causes those customers to incur that maximum hour charge as if they had used power  
7       every day of the week.  These customers would receive bills which exceed their cost  
8       impact on the system.  Demand charges are not based on coincident peak usage.  These  
9       customers have limited or no impact on peak demand generation facilities, which are  
10      allocated in the CCOS on coincident peak hours.  They have no impact on transmission  
11      facilities which are allocated on a four coincident peak hours in the summer.  Although  
12      distribution facilities are allocated in the CCOS study based on class non-coincident  
13      peaks, the actual impact of these customers' non-coincident peaks will depend on the  
14      demands for the local area in proximity to the church.  In addition, the off-peak  
15      characteristic of HOW customers is likely to provide considerable benefit for distribution  
16      sizing in the upstream segments of the distribution system which are sized for a larger  
17      local area which encompasses numerous types of customers.  In short, HOW customers  
18      provide beneficial load diversity (as measured by customer peaks vs. system non-  
19      coincident and coincident peaks) which is not recognized by demand charge pricing.

1 **Q. IS AUSTIN ENERGY PLANNING TO PERFORM STUDIES THAT ARE**  
2 **RELEVANT TO THE HOW RATE?**

3 A. Yes. Among the studies Austin Energy proposes prior to the next cost of service  
4 assessment is a study of the rate structure for the S1 class and a study of demand charges  
5 for customers peaking outside AE system peak.<sup>84</sup> There are approximately 58 HOW in  
6 the S1 class<sup>85</sup> and many HOW accounts experience peak on weekends, outside the AE  
7 system peak. Both of these studies could result in rates that would mitigate the rate shock  
8 that some HOWs will experience under the proposal in this rate case.

9 **Q. WHAT ARE YOUR CONCERNS ABOUT DISCONTINUING THE HOUSES OF**  
10 **WORSHIP TRANSITION?**

11 A. My first concern is the rate shock that will be experienced by some of the Houses of  
12 Worship. Avoiding rate shock is a well-established principle of utility ratemaking. In the  
13 current rate case Austin Energy is not proposing to raise rates to any customer class, and  
14 rate for most will be lowered. It is not fair to subject HOWs, some of them very small  
15 and relying on volunteer staff, to experience significant rate increases and do nothing to  
16 mitigate this rate increase.

17 Second, I disagree with moving the HOWs off the transition discount when  
18 Austin Energy plans to perform rate studies that might result in a more appropriate rate  
19 treatment for HOW, including a study of peak usage measurement in the commercial

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<sup>84</sup> AELIC 8-4, Attachment 1 page 27 of 35.

<sup>85</sup> ICA 1-10, bill frequency = 709 in FY 2014.

1 class and the rate structure of the S1 class.<sup>86</sup> A HOW with peak usage on the weekend is  
2 exactly the type of customer who could benefit from the results of a study addressing off  
3 peak demand. Many of the smallest HOW are in the S1 class and may benefit from a  
4 revised rate structure. These studies should be done prior to any rate change.

5 Third, understanding and controlling demand is challenging for many customers,  
6 including smaller HOW who may rely on volunteer or part time staff and almost certainly  
7 do not have access to an energy manager. The changes Austin Energy is proposing to the  
8 S2 class adds another layer of complexity to the HOWs who are losing their discount.

9 **Q. WHAT ARE YOUR RECOMMENDATIONS?**

10 A. I propose the following:

- 11 • Extend the transition for HOWs—retain the cap of 13.015 cents per kWh and the  
12 practice of measuring peak usage during weekdays. Preferably, AE should absorb the  
13 discount, instead of re-allocating the cost to other customers. [This is consistent with](#)  
14 [NewGen’s recommendation to provide relief from rate shock for low power factor](#)  
15 [customers without reallocating the cost to other customers.](#) The transition should not  
16 end until after the two studies referenced above have been completed and the next  
17 rate case is completed.<sup>87</sup>
- 18 • Include outreach to HOWs during the study periods.
- 19 • Continue outreach to HOWs, prioritizing those who would experience the largest rate  
20 increase absent the transition. Austin Energy should conduct trainings to help HOWs  
21 understand and manage demand. It should also work with HOWs to identify facilities  
22 that might benefit from option time-of-use rates and offer to run “shadow bills”  
23 comparing rates under current usage with and without the time-of-use option.

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<sup>86</sup> See Appendix E.

<sup>87</sup> In addition, the IHE should order AE to include HOW customers in the two studies above.

## **VII. POLICY ISSUES**

### **A. Below Average Customer Satisfaction**

**Q. WHAT DOES AUSTIN ENERGY SAY ABOUT CUSTOMER SATISFACTION IN THE RATE FILING PACKAGE?**

A. Austin Energy does not directly address customer satisfaction. Austin Energy addressed “Customer Success” on p. 3-38 (Bates 067) stating: “Austin Energy’s guiding principle is to make it easy for its customers to work with the utility and to provide them with products and programs they regard as valuable.” This section of the Tariff Package provides descriptive information on Energy Conservation programs, Green Building, Energy Conservation Audit and Disclosure, Solar, and Customer Care.

**Q. DID AUSTIN ENERGY PROVIDE ANY INFORMATION ABOUT CUSTOMER SATISFACTION?**

A. Yes. ICA 2-1 asked for results of recent customer satisfaction surveys. Austin Energy provided the following information for FY 15:

- The overall satisfaction survey rating for Austin Energy was 59%
- Satisfaction for the walk-in service centers averaged 88% for residential and commercial customers
- Satisfaction with the residential rebate program was 80%

**Q. WHAT IS THE OVERALL SATISFACTION SURVEY?**

A. According to Austin Energy’s response to ICA 5-6: “This survey is conducted by phone and is written by Austin Energy staff and conducted by a consultant with a call center. The survey was conducted on 120 residential customers in both FY 2015 and FY 2014.”

1 **Q. DID AUSTIN ENERGY PROVIDE COPIES OF THE SURVEY OR ANALYSIS**  
2 **OF THE RESULTS?**

3 A. No. Austin Energy objected to ICA 5-6 requesting the surveys, methodologies and  
4 results, of the overall customer satisfaction surveys, stating “The surveys and their  
5 detailed findings are considered competitive information and are being withheld.” Austin  
6 Energy did provide detailed information on the walk-in information center satisfaction  
7 surveys and the residential rebate program surveys.

8 **Q. IS IT YOUR OPINION THAT 59% SATISFACTION IS AN ACCEPTABLE**  
9 **RATING?**

10 A. No. The results indicate that about 40% of Austin Energy’s residential customers are not  
11 satisfied with the utility. Without seeing the detail of the surveys it is not possible to  
12 know whether the dissatisfaction is related to rates, communications, service or  
13 something else.

14 **Q. ARE YOU AWARE OF OTHER CUSTOMER SATISFACTION SURVEYS OF**  
15 **AUSTIN ENERGY CUSTOMERS?**

16 A. Yes. J.D. Power customer satisfaction surveys are well known by consumers and the  
17 utility industry.<sup>88</sup> According to the 2015 results Austin Energy is rated 654 on a 1000-  
18 point scale. It is below average for South Region Midsize Segment (average 684) and  
19 below the overall national average of 668. The J. D. Power press release highlights rates,  
20 communications with customers, and outages as key factors in their survey.

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<sup>88</sup> A link to the 2015 survey is found at: <http://www.jdpower.com/press-releases/2015-electric-utility-residential-customer-satisfaction-study>.

1 **Q. WHAT IS YOUR RECOMMENDATION?**

2 A. Customer satisfaction is a key metric of utility performance and Austin Energy should  
3 strive for significantly improved customer satisfaction ratings. It is not possible to make  
4 a detailed recommendation without knowing the survey questions and specific results  
5 behind the overall customer satisfaction rating. I recommend Council direct Austin  
6 Energy to develop a plan to improve its customer satisfaction ratings. I further  
7 recommend Austin Energy work with the Electric Utility Commission, ratepayer  
8 advocates and the public in developing, executing and monitoring the plan for improved  
9 customer satisfaction.

10 **B. Residential Pilot Programs, Generally**

11 **Q. HAS AUSTIN ENERGY INCLUDED ANY PILOT PROGRAMS FOR**  
12 **RESIDENTIAL CUSTOMERS IN THE TARIFF PACKAGE?**

13 A. Yes. In the FY 2016 budget Council approved three additional pilots<sup>89</sup> that are included  
14 in the “Residential Service Pilot Program” section of the proposed City of Austin Tariff  
15 Schedule<sup>90</sup>:

- 16 • Time-of-Use Rates
- 17 • Prepayment Rates
- 18 • Plug-In Electric Vehicle Charging Rates

19 The Time-of-Use pilot began January 1, 2016; the Plug in EV pilot has not yet  
20 begun<sup>91</sup>; the prepayment pilot was slated to begin April 1, a date later revised to May 2<sup>92</sup>.

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<sup>89</sup> [https://assets.austintexas.gov/budget/15-16/downloads/Vol2Approved\\_Final.pdf](https://assets.austintexas.gov/budget/15-16/downloads/Vol2Approved_Final.pdf). See p. 544; ICA 2-18C.

<sup>90</sup> Beginning at Bates 664.

1 **Q. DO YOU AGREE THAT AUSTIN ENERGY SHOULD CONDUCT PILOT**  
2 **PROGRAMS OF NEW OR OPTIONAL RESIDENTIAL RATES AND RATE**  
3 **DESIGNS?**

4 A. Yes. I agree with Austin Energy's plan to pilot and study these proposals. New and  
5 alternative rates and rate designs have the potential to provide benefits to some  
6 customers, as well as to the utility. For example, if properly structured, an opt-in time-of-  
7 use rate could help lower peak usage, both reducing peak demand and saving money for  
8 those customers with flexibility to shift their usage off peak. However, the opposite is  
9 also true—an improperly structured rate design could result in some customers seeing  
10 significantly higher bills, and/or cross subsidies across customer groups (for example,  
11 between participants and nonparticipants).

12 **Q. DID THE ELECTRIC UTILITY COMMISSION REVIEW OR APPROVE ANY**  
13 **OF THE THREE FY 16 PILOTS PRIOR TO ADOPTION IN BUDGET?**

14 A. No.<sup>93</sup>

15 **Q. DID THE CITY COUNCIL RECEIVE ANY BRIEFINGS ON THE THREE FY 16**  
16 **PILOTS OTHER THAN DISCUSSION AND ADOPTION AS PART OF THE**  
17 **BUDGET?**

18 A. No.<sup>94</sup>

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<sup>91</sup> ICA 2-21.

<sup>92</sup> <http://www.austintexas.gov/edims/document.cfm?id=252239>; ICA 2-21.

<sup>93</sup> ICA 5-10.

<sup>94</sup> ICA 2-18, ICA 5-9.

1   **Q.   HAS AUSTIN ENERGY PROVIDED THE COSTS OF EACH PILOT, BROKEN**  
2       **OUT BY CAPITAL COSTS AND OPERATIONS AND MAINTENANCE**  
3       **EXPENSES?**

4   A.   No.<sup>95</sup> Austin Energy provided no cost information for the Time of Use and Plug-In EV  
5       pilots, stating “the reason for the pilot programs is to collect information related to O&M  
6       and capital expenses, incremental costs, and savings.” For the prepayment pilot Austin  
7       Energy has identified a budget of \$57,999, but has not allocated the amount between  
8       O&M and capital.

9   **Q.   DO THE PILOTS HAVE FIRM STARTING AND END DATES?**

10  A.   This is not at all clear. For the EV and Time-of-Use pilots, no information was provided  
11       referencing the time period the pilots would be in effect, although the tariff requires  
12       customers to remain on the pilot rate for 12 consecutive billing cycles or pay a penalty.  
13       A memo from Interim General Manager Mark Dombroski to the Mayor and City  
14       Council<sup>96</sup> refers to the pilots as “limited” and “temporary”. The prepayment pilot was  
15       described by Mr. Dombroski as terminating in September of 2016. However, all of the  
16       pilots, including the prepayment pilot, are included in the proposed tariffs for FY 2016,  
17       and Austin Energy has referred to future “full deployment” of the rates.<sup>97</sup> Therefore, I  
18       assume the pilots and/or the rate designs will all be in effect beyond September of 2016.

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<sup>95</sup> ICA 2-12, ICA 2-21, AELIC 2-25.

<sup>96</sup> <http://www.austintexas.gov/edims/document.cfm?id=252239>.

<sup>97</sup> ICA 2-17.



1 **Q. WHAT DOES THE ELECTRIC VEHICLE PUBLIC CHARGING PILOT**  
2 **PROGRAM TELL US ABOUT AUSTIN ENERGY’S APPROACH TO PILOT**  
3 **PROGRAMS?**

4 A. The Electric Vehicle Public Charing Pilot began in FY 2012, four years ago. Yet Austin  
5 Energy refers to the pilot as being it is “early stages” and states it has not conducted a  
6 comprehensive cost of service examination to verify if there are subsidies created by the  
7 program.<sup>98</sup>

8 **Q. DO YOU AGREE WITH AUSTIN ENERGY’S APPROACH TO THE PILOT**  
9 **PROGRAMS?**

10 A. Not entirely. As I stated previously, there is value to both the utility and its customers to  
11 explore new or alternative rates through pilots prior to full deployment. However, I see  
12 several flaws in Austin Energy’s approach:

- 13 • **Austin Energy’s pilot do not have firm time limits.** A rate should not go on for  
14 years under the “pilot” designation. It is concerning that Austin Energy would refer  
15 to the four-year-old public charging station pilot as “in its early stages.”
- 16 • **Austin Energy has not fully developed the terms and conditions of the pilot, its**  
17 **goals, customer education, performance criteria and evaluation metrics up front.**  
18 For example, Austin Energy Low Income Customers asked detailed questions about  
19 the prepayment pilot. In responses provided less than one month prior to the (at that  
20 time) April 1 start date, Austin Energy responded to several key questions about the  
21 pilot and customer protections with answers such as “currently reviewing” and “not  
22 yet determined”.<sup>99</sup>
- 23 • **Austin Energy has not sufficiently engaged city policymakers in the design and**  
24 **review of these pilots.** The ICA team was surprised by how little public discussion  
25 there was concerning the pilots, particularly the prepayment pilot which Austin  
26 Energy identified internally as potentially controversial<sup>100</sup>. The role of the Electric

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<sup>98</sup> NXP/Samsung 1-90.

<sup>99</sup> See responses of March 10, 2016 to AELIC 2-1, 2-8, 2-9, 2-10, 2-12, 2-15.

<sup>100</sup> ICA 2-18 Attachment 4, p. 28 of 38.

Utility Commission is to: “Review and analyze all policies and procedures of the electric utility including the electric rate structure, fuel costs and charges, customer services, capital investments, new generation facilities, selection of types of fuel, budget, strategic planning, regulatory compliance, billing procedures, and the transfer of electric utility revenues from the utility fund to the general fund,”<sup>101</sup> yet Austin Energy did not brief the EUC on the pilots. Although the Council has an Austin Energy Oversight Committee, the only presentation given Council on these pilots came during the FY 16 budget process, a time when Council members are reviewing a massive amount of information related to the entire city budget.

**Q. WHAT ARE YOUR RECOMMENDATIONS?**

A. With regard to pilot projects in general:

- Proposed pilots should be reviewed by the Electric Utility Commission and the Council, separate and apart from the budget process.
- Where a pilot has identified stakeholders, such as low income advocates, Austin Energy should consult these groups about pilot goals and design, prior to initiating that pilot.
- Pilots should be given a firm end date; no pilot should go on indefinitely or for more than two years without a comprehensive review. If it is determined that additional study is needed, the pilot could be extended.
- Austin Energy should fully develop the terms and conditions of the pilot, its goals, customer education, performance criteria, potential cross subsidies, and evaluation metrics prior to initiating a pilot.

**1. Prepayment Pilot Program Concerns**

**Q. DO YOU HAVE SPECIFIC CONCERNS ABOUT THE PREPAYMENT PILOT?**

A. Yes. As Austin Energy internal documents reveal, prepayment programs have “high-level risks”, including potential disapproval by customer advocacy groups or by city council members.<sup>102</sup> Therefore, it is imperative for success that AE include stakeholders in discussions regarding the design and evaluation criteria for any prepayment pilot

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<sup>101</sup> <http://www.austintexas.gov/euc>.

<sup>102</sup> AE Response to ICA 2-18, p. 200.

1 program at the earliest opportunity. Prepayment pilots can be complicated and are often  
2 controversial. The following issue includes some of the concerns likely to be raised by  
3 consumer advocates and which should be addressed in a stakeholder collaborative:

4 **1. Bypass of Billing and Disconnection Protections.** Austin Energy's  
5 proposal for a prepayment program includes the following "fine print" provisions, which  
6 would apply different service conditions, and arguably less consumer protections, for  
7 participants in the program, as compared to normally billed residential customers:

- 8 • In lieu of a written notice of disconnection, Austin Energy will provide program  
9 participants with a notice by text message, email, or phone call to alert them when  
10 the account balance is at or below a projected five (5) day usage. It is the  
11 participant's sole responsibility to provide Austin Energy with current and correct  
12 contact information for such notice message; nor is it Austin Energy's  
13 responsibility to verify that the notice message was delivered nor refrain from  
14 disconnecting service, if it cannot deliver the notice message due to insufficient or  
15 incorrect information.
- 16 • Regulations and policies concerning disconnection of service due to weather,  
17 critical medical conditions, or other circumstances shall not apply to service under  
18 this rate schedule.<sup>103</sup>

19 Disconnection rules and policies designed to provide adequate notice of  
20 disconnection and to protect the health and safety of consumers from disconnection  
21 during extreme weather conditions should not simply be bypassed or waived, at least not  
22 without the creation of equally protective provisions that apply to prepayment  
23 participants.

24 **2. Low-income customers may be targeted, and disconnections may rise**  
25 **dramatically.** Even if a prepayment program is not specifically targeting low income or  
26 payment troubled customers, the benefit of not having to supply a security deposit in

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<sup>103</sup> AE Response to ICA 2-18, p. 236.

1 order to have prepayment service is likely to attract such customers. Other utilities have  
2 experienced a higher number of disconnections and spikes in disconnections through  
3 their prepayment programs. One utility reports that only 60% of its prepayment  
4 participants have not experienced some disconnection activity.<sup>104</sup>

5 **Q. WHAT IS YOUR RECOMMENDATION?**

6 A. I recommend Austin Energy develop a collaborative of stakeholder groups, including low  
7 income advocates, to review and make recommendations on the prepayment pilot,  
8 including adopting consumer protections equivalent to current consumer protections. In  
9 addition the collaborative should address ways to ensure a prepayment plan is not  
10 targeted at lower income households.

11 **C. “Pick Your Own Due Date” Option for Consumers**

12 **Q. WHAT IS A “PICK YOUR OWN DUE DATE” OPTION FOR UTILITY**  
13 **CONSUMERS?**

14 A. Also called “Preferred Due Date” or “Pick-A-Date”, this option allows the utility to offer  
15 each customer the ability to choose the timing of their monthly billing cycle, allowing for  
16 a customized due date each month that best suits that customer’s bill paying patterns.  
17 This option is particularly convenient for customers on fixed incomes who wish to time  
18 their bill payments to match the receipt of their monthly payroll check or benefit check.  
19 “Pick Your Own Due Date” programs are growing in popularity among investor-owned  
20 and municipal utilities. Several City Council members inquired about the possibility of

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<sup>104</sup> AE Response to ICA 2-18, p. 181.

1 AE implementing such a program during the most recent City of Austin Utility Oversight  
2 Committee meeting.<sup>105</sup>

3 **Q. CAN YOU GIVE AN EXAMPLE OF HOW IS THIS OPTION IS MADE**  
4 **AVAILABLE TO CONSUMERS BY ANOTHER UTILITY?**

5 A. The Texas PUC permits the electric utilities that it regulates to offer customers the option  
6 of choosing their own due date. Entergy Texas provides this explanation of its program  
7 to consumers on its website:

8 Q. Can I change the date that my bill would be due each month? I  
9 live on a fixed income and my check comes at the first of the  
10 month, but your bill is due around the 20th of each month.

11 A. Yes, Entergy understands that some customers receive their  
12 income checks on a monthly basis. Our **Pick-A-Date** program  
13 provides you the ability to select a billing date that best suits  
14 your situation. Once set up in the program your account will  
15 bill on the date selected. You can sign up for Pick-A-Date by  
16 logging on to My Account Online.<sup>106</sup>

17 **Q. WHAT IS THE CURRENT STATUS OF AUSTIN ENERGY'S ABILITY TO**  
18 **OFFER THIS OPTION TO ITS CONSUMERS?**

19 A. Austin Energy states, "At this time, customers are not allowed to choose their due date.  
20 Research is required to determine the technical and operational changes required to allow  
21 customers to change their bill due date. However, testing is currently underway for the  
22 required technical changes to determine feasibility of the program."<sup>107</sup>

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<sup>105</sup> April 28, 2016 committee meeting.

<sup>106</sup> Frequently Asked Questions: [http://www.entergy-texas.com/faq/faq\\_consumer.aspx#b8](http://www.entergy-texas.com/faq/faq_consumer.aspx#b8).

<sup>107</sup> AE Response to ICA 2-2.

1   **Q.     WHAT IS YOUR RECOMMENDATION?**

2   A.     Austin Energy should be required to implement a “Pick Your Own Due Date” option for  
3           consumers as soon as it is technically feasible to do so, and then publicly promote this  
4           billing accommodation to its consumers.

5           **D.     Timing of Next Rate Review Proceeding**

6   **Q.     WHAT DOES AE SAY ABOUT THE POTENTIAL TIMING OF THE NEXT**  
7           **RATE REVIEW PROCEEDING?**

8   A.     The Austin Energy proposal in this rate review proceeding states:

9                   Due to the significant deviation from cost of service for some  
10                  customer classes and the list of issues for further research, Austin  
11                  Energy suggests that the next cost of service update be conducted  
12                  upon the conclusion of these studies in two to three years, rather  
13                  than the maximum five years included in current City Council  
14                  policy.<sup>108</sup>

15   **Q.     WHAT DO YOU RECOMMEND?**

16   A.     I agree with the idea that, following the conclusion of this proceeding, Austin Energy’s  
17           cost of service should be examined more frequently than five years, particularly in  
18           consideration of the many issues that Austin Energy plans to study in the interim,<sup>109</sup> and  
19           the several issues that I am proposing to be deferred for study until the next proceeding.  
20           Allowing for a thorough and transparent analysis of Austin Energy’s cost of service every  
21           2-3 years, if possible, is a good policy, and is much preferable to allowing rates to change  
22           over time without such a full review.

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<sup>108</sup> Tariff Package, p. 029.

<sup>109</sup> Tariff Package, Appendix E, pp. 372-373.

1       **E.       Restricting Piecemeal Rate Changes**

2       **Q.       WHY IS IT PREFERABLE FOR ELECTRIC RATES TO CHANGE ONLY**  
3       **AFTER A FULL COST OF SERVICE REVIEW?**

4       A.       There is an interrelationship among many cost of service components (i.e., expenses,  
5       investments, revenues) within a test year. When adjustments are made to electric rates  
6       for one item of expense outside of a full rate review of all components, then a mismatch  
7       can occur which distorts the overall cost of service. For instance, rates could be  
8       increased due to an increase in one expense, while ignoring a reduction that occurred in  
9       another expense during the same time period. Austin Energy already has three pass-  
10      through mechanisms (the Power Supply Adjustment charge, the Regulatory Charge, and  
11      the Community Benefit Charge) which can change electric rates in isolation of the  
12      changes that may be occurring to base rates. It is important that no more isolated changes  
13      be allowed in order to preserve the fairness and affordability of electric rates overall.

14             A guiding principle advanced by Austin Energy is that “The rate review process  
15      should be transparent, including public involvement”.<sup>110</sup> Thus far, the current rate review  
16      proceeding has allowed unprecedented public involvement and scrutiny of Austin  
17      Energy’s electric rates with the goal of producing an independent opinion regarding the  
18      level and allocation of the cost of service. Rate changes, including changes in rate  
19      design, that occur subsequent to this proceeding are not likely to be subjected to the  
20      same level of transparency and scrutiny, and have the potential to distort the relationship  
21      of rates to the overall cost of service. I believe that it is important to ensure that the rate

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<sup>110</sup> Tariff Package, p. 017, Principle #8.

1 changes resulting from this proceeding will remain in place until the next full rate review,  
2 without the creation of any new mechanisms that have the potential to cause isolated  
3 changes to electric bills.

4 **Q. WHY ARE YOU CONCERNED ABOUT RATE CHANGES BETWEEN RATE**  
5 **CASES?**

6 A. The Tariff Package makes references to changes that would or could be implemented  
7 outside of this rate case. For example, “Looking beyond year one, there are many rate-  
8 making consideration related to moving all customer classes closer to cost of serve.  
9 These considerations include: altering the number of years over which changes can be  
10 made, modifying the number of incremental steps necessary to move closer to cost of  
11 service, adjusting the steepness of the five Residential tiers, reducing the number of  
12 Residential tiers, and changing the magnitude of the customer charge.”<sup>111</sup> In response to  
13 a question, Austin Energy also stated: The City Council can adopt changes to the  
14 residential rates, the customer charge and rate design at any time, including prior to the  
15 filing a new rate case.”<sup>112</sup>

16 **Q. WHAT IS YOUR RECOMMENDATION?**

17 A. I recommend that Council should not adopt changes in rates or rate design, outside of the  
18 already established PSA and pass-through charges, during the time period in between rate  
19 review proceedings.

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<sup>111</sup> Tariff Package Bates p. 024.

<sup>112</sup> ICA 2-8. See also ICA 2-9 and 2-10.



1           **F.       Issues for study prior to the next rate review**

2   **Q.       DOES AUSTIN ENERGY PROPOSE ANY STUDIES OR RESEARCH PRIOR TO**  
3   **THE NEXT RATE REVIEW?**

4   A.    Yes.   Appendix E<sup>113</sup> to the Tariff Package lists 8 proposed studies address both  
5       residential and nonresidential rate design. These include:

6               Residential:

- 7               •   Review tier structure of residential rates  
8               •   Lifeline study of residential energy uses  
9               •   Study customer-related cost recovery charges for multi-family, single-  
10              family and solar-installed residences;  
11              •   Charges for three-phase residential customers

12              Non-Residential:

- 13              •   Rate structure for Secondary Voltage Service 1  
14              •   Downtown network rates  
15              •   Peak usage measurement  
16              •   Power factor charges versus Kilovolt-ampere reactive (“kvar”) charges

17   **Q.       DO YOU AGREE WITH THESE STUDIES?**

18   A.    Yes.   With regard to the residential studies, the four proposed studies are inter-related  
19       questions involving an analysis of costs and cost allocation, and decisions regarding rate  
20       design.   Austin Energy has often referred to the customer charge as being below cost, a  
21       conclusion with which I disagree.   Focusing on these issues before the next rate review,  
22       with the recommendations I make below, will be beneficial to residential customers.   As  
23       described earlier in my testimony, the studies related to the secondary classes are needed

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<sup>113</sup> Tariff Package, Appendix E, Bates p. 372-373.

1 to address disparities for some customers, including Houses of Worship and others in the  
2 lower band of the S2 class.

3 **Q. WHAT IS YOUR RECOMMENDATION?**

4 A. I recommend the following:

- 5 • The identified studies should be completed prior to the next rate review.
- 6 • Austin Energy should engage the Electric Utility Commission and stakeholder groups  
7 during the study process. Stakeholder groups for residential customers should include  
8 groups such as residential consumer advocates, low-income advocates, solar  
9 advocates and representatives of ratepayers outside the City. Houses of Worship and  
10 representatives of small business should be included as stakeholders for the non-  
11 residential studies.
- 12 • Austin Energy should provide technical expertise to the EUC and stakeholder groups  
13 during these studies. It is essential for the public, and the Council, to know the bill  
14 impacts of various proposals that could be considered under each of these studies.  
15 The EUC and most stakeholders typically would not have access to the technical  
16 assistance to run alternative rate designs, review the final approved cost of service  
17 study, etc.

18 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

19 A. Yes.

## SUMMARY OF QUALIFICATIONS

### CLARENCE JOHNSON

<b>EDUCATION</b>	<p>Bachelor of Science, Political Science, University of Houston.</p> <p>Master of Arts, College of Social Science (Interdisciplinary/Urban Studies), University of Houston.</p>
<b>EXPERIENCE</b>	<p>Mr. Johnson has more than 25 years experience as an expert witness and analyst related to electric and telecommunications utility issues.</p>
<b>CURRENT EMPLOYMENT</b>	<p>Mr. Johnson currently provides professional consulting and analytical analyses regarding regulatory and public policies related to public utilities and the energy industry.</p>
<b>PREVIOUS EMPLOYMENT 1983-2008</b>	<p>From September 1983 to June 2008, Mr. Johnson was a Regulatory Analyst for the Office of Public Utility Counsel. He was the professional staff person with primary responsibility for advising the Public Counsel on economic and regulatory policy issues. His responsibilities included: presenting expert testimony on regulatory matters; research related to rate filings of regulated public utilities; acting as a non-testifying expert and advising attorneys in cross-examination of witnesses and development of trial exhibits for utility regulatory proceedings; analyzing policies and practices for regulating public utilities; and preparing comments on proposed Public Utility Commission rules; assisting financial and economic staff in the development and preparation of testimony; providing expert testimony on selected issues; preparation of reports to the Legislature regarding the utility regulatory process.</p>
<b>EMPLOYMENT BEFORE 1983</b>	<p>During the period 1977 to 1983, Mr. Johnson extensively engaged in analysis and supervision of public interest advocacy programs. He directed two non-profit corporations involved in public policy research from 1978 to 1980 and 1982 to 1983, respectively; responsibilities included overall management of the corporations, negotiation and management of grants and contracts, supervision of research activities, and presentations of research findings to legislative and administrative governmental entities. From 1980 to 1982, he also performed policy analysis and substantive research on the impact of governmental policies for two publicly-funded entities. His responsibilities for the statewide support center for legal services programs in Texas assessed the effect of federal and state regulatory changes upon indigent clients. As an analyst for the Texas State Senate's Natural Resources</p>

Committee, Mr. Johnson was responsible for research related to low-level radioactive waste disposal and low-head hydropower, and the committee's staff's interim report on energy conservation.

**AWARDS**

Mr. Johnson was the recipient of the first annual Texas Outstanding Public Service Award in 1988.

**MEMBERSHIP**

American Economics Association.

**TESTIMONY ON  
BEHALF OF  
TEXAS OFFICE  
OF PUBLIC  
UTILITY  
COUNSEL**

Docket No. 6588, Re Southwestern Bell Telephone Company,  
Subject: Declassification of Documents.

Docket Nos. 7195 and 6755, Re Gulf States Utilities Company,  
Subject: Rate Design/Cost Allocation.

Docket No. 7510, Re West Texas Utilities Company,  
Subject: Rate Design/Cost Allocation.

Docket No. 8095, Re Texas-New Mexico Power Company,  
Subject: Rate Design/Cost Allocation.

Docket No. 8363, Re El Paso Electric Company,  
Subject: Rate Design/Cost Allocation.

Docket No. 8425, Re Houston Lighting & Power Company,  
Subject: Revenue Requirements.

Docket No. 8425, Re Houston Lighting & Power Company,  
Subject: Rate Design/Cost Allocation.

Docket No. 8646, Re Central Power and Light Company,  
Subject: Revenue Requirements.

Docket No. 8646, Re Central Power and Light Company,  
Subject: Rate Design/Cost Allocation.

Docket No. 8646, Re Central Power and Light Company,  
Subject: Interim Rate Relief.

Docket No. 8555, Proceedings Concerning Houston Lighting &  
Power Company on Remand From Cause No. C-  
5705 and Cause No. 352,044,  
Subject: Determination of Remand Amount.

Docket No. 8928, Re Texas-New Mexico Power Company,  
Subject: Rate Design/Cost Allocation.

Docket No. 8585, Re Southwestern Bell Telephone Company,  
Subject: Revenue Requirements/Affiliates.

Docket No. 8585, Re Southwestern Bell Telephone Company,  
Subject: Reply, Revenue Requirements/Affiliates.

Docket No. 8585, Subject:	<u>Re Southwestern Bell Telephone Company,</u> Reply, Rate Design.
Docket No. 8585, Subject:	<u>Southwestern Bell Telephone Company,</u> Proposed Non-Unanimous Stipulation.
Docket No. 9300, Subject:	<u>Texas Utilities Electric Company,</u> Revenue Requirement.
Docket No. 9300, Subject:	<u>Texas Utilities Electric Company,</u> Cost Allocation and Rate Design.
Docket No. 9300, Subject:	<u>Texas Utilities Electric Company,</u> Prudence of Plant Acquisition.
Docket No. 9561, Subject:	<u>Central Power and Light Company,</u> Revenue Requirement.
Docket No. 9561, Subject:	<u>Central Power and Light Company,</u> Cost Allocation and Rate Design.
Docket No. 9578, Subject:	<u>Sugar Land Telephone Company,</u> Inquiry into Sale.
Docket No. 9850, Subject:	<u>Houston Lighting &amp; Power Company,</u> Revenue Requirement.
Docket No. 9850, Subject:	<u>Houston Lighting &amp; Power Company,</u> Cost Allocation and Rate Design.
Docket No. 9850, Subject:	<u>Houston Lighting &amp; Power Company,</u> Settlement Testimony: Revenue Requirement and Rate Design.
Docket No. 9981, Subject:	<u>Central Telephone Company,</u> Revenue Requirement/Affiliates.
Docket No. 10894, Subject:	<u>Gulf States Utilities Company,</u> Affiliate Transactions/Power Purchases.
Docket No. 11735, Subject:	<u>Texas Utilities Electric Company,</u> Revenue Requirement and Rate Design.

Docket No. 11892, General Counsel's Original Petition for Generic Proceeding Regarding Purchased Power,  
Subject: Impact of Purchased Power on Cost of Capital.

Docket No. 12700, El Paso Electric Company,  
Subject: Acquisition, Revenue Requirement and Rate Design.

Docket No. 12957, Houston Lighting & Power Company,  
Subject: Contract Pricing Tariff.

Docket No. 13100, Texas Utilities Electric Company,  
Subject: Competitive Pricing Tariffs.

Docket No. 13575, Texas Utilities Electric Company,  
Subject: Demand Side Management and Purchase Power Recovery.

Docket No. 12065, Houston Lighting & Power Company,  
Subject: Revenue Requirement/Plant Cancellation/Prudence.

Docket No. 12065, Houston Lighting & Power Company,  
Subject: Cost Allocation and Rate Design.

Docket No. 13943, Gulf Coast Power Connect,  
Subject: Transmission Line CCN.

Docket No. 13575, TUEC Application for Relief Regarding Recovery Solicitations,  
Subject: DSM and Purchase Power Cost Recovery.

Docket No. 13369, West Texas Utilities Company,  
Subject: Cost Allocation and Rate Design.

Docket No. 14435, Southwestern Electric Power Co.,  
Subject: Rate Design.

Docket No. 14716, Texas Utilities Electric Company,  
Subject: Wholesale Competitive Rate.

Docket No. 14965, Central Power and Light Company,  
Subject: Cost Allocation, Rate Design and Competitive Issues.

Docket No. 14965, Central Power and Light Company,  
Subject: Reply, Cost Allocation, Rate Design and  
Competitive Issues.

Docket No. 15560, Texas-New Mexico Power Company,  
Subject: Competitive Issues.

Docket No. 16705, Entergy Gulf States, Inc.,  
Subject: Cost Allocation, Rate Design and Competitive  
Issues.

Docket No. 16705, Entergy Gulf States, Inc.,  
Subject: Reply, Cost Allocation, Rate Design and  
Competitive Issues.

Docket No. 16995, Central Southwest Corp.,  
Subject: Integrated Resource Planning.

Docket No. 17751, Texas-New Mexico Power Company,  
Subject: Rate Design and Competitive Issues.

Docket No. 18845, CPL, WTU, and SWEPCO,  
Subject: Integrated Resource Planning.

Docket No. 21527, TXU Financing Order,  
Subject: Cost Allocation.

Docket No. 21528, CPL Financing Order,  
Subject: Cost Allocation.

Docket No. 21591, Sharyland Utilities Initial Rates & Tariffs,  
Subject: Deferrals.

Docket No. 21956, Reliant Business Separation Plan,  
Subject: Price to Beat and Capacity Auction.

Docket No. 22344, Generic Rate Design and Customer Classification  
for TDUs,  
Subject: Rate Design.

Docket No. 22349, TNMP Unbundling,  
Subject: Competitive Transition Charge and Revenue  
Requirements/Cost Allocation/Rate Design.



Docket No. 22350, TXU Unbundling,  
Subject: Competitive Transition Charge.

Docket No. 22351, Southwestern Public Service Company Unbundling,  
Subject: Cost Allocation/Rate Design.

Docket No. 22352, Central Power & Light Company,  
Subject: Competitive Transition Charge.

Docket No. 22355, Reliant Unbundling,  
Subject: Non-Bypassable Charges and Competitive Transition Charge/Cost Allocation/Rate Design.

Docket No. 22356, Entergy Gulf States Utilities Unbundling,  
Subject: Revenue Requirements/Cost Allocation/Competitive Transition Charge/Settlement Rate Design.

Docket No. 24194, Application of TNMP to Establish Price to Beat Fuel Factor,  
Subject: Fuel and purchased power costs.

Docket No. 25230, Joint Application for Approval of Stipulation Regarding TXU Electric Company Transition to Competition Issues,  
Subject: Retail Clawback Provisions of Non-Unanimous Agreement.

Docket No. 25314, Application of West Texas Utilities Company and Mutual Energy WTU to Establish a Fuel Reconciliation Methodology for Southwest Power Pool (SPP) Customers,  
Subject: Fuel Cost Method.

Docket No. 24336, Application of Entergy Gulf States, Inc. for Approval of Price to Beat Factor,  
Subject: Unaccounted for Energy.

Docket No. 23320, Petition of ERCOT for Approval of the ERCOT Administrative Fee,  
Subject: ERCOT Fee Structure.

Docket No. 26194, El Paso Electric Company Fuel Reconciliation,  
Subject: Purchased Power and Off-System Sales.

Docket No. 27576, Application of Texas-New Mexico Power Company for Reconciliation of Fuel Costs,  
Subject: Fuel Reconciliation.

Docket No. 28813, Inquiry Into Rates of Cap Rock Energy,  
Subject: Revenue Requirements/Cost Allocation/Rate Design.

Docket No. 28840, Application of AEP Texas Central Company for Change in Rates,  
Subject: Cost Allocation/Rate Design/Affiliate Transactions.

Docket No. 30485, Application of CenterPoint Energy Houston Electric, LLC For A Financing Order,  
Subject: Transition Charge Recovery.

Docket No. 30143, Petition of El Paso Electric Company to Reconcile Fuel Costs (Initial and Rebuttal Testimonies),  
Subject: Fuel Reconciliation.

Docket No. 30706, Application of CenterPoint Energy Houston Electric, LLC for A Competition Transition Charge,  
Subject: Competitive Transition Charge Structure.

Docket No. 31315, Application of Entergy Gulf States, Inc. for Approval of Incremental Purchased Capacity Recovery Rider,  
Subject: Purchase Power Capacity Rates.

Docket No. 31544, Application of Entergy Gulf States, Inc. for Recovery of Transition to Competition Costs,  
Subject: Allocation of Transition Costs.

Docket No. 31994, Application of Texas-New Mexico Power Company's to Establish a Competition Transition Charge Pursuant to P.U.C. Subst. R. 25.263(N),  
Subject: Competition Transition Charge.

Docket No. 32475, Application of AEP Texas Central Company for a Financing Order,  
Subject: Securitization of Stranded Costs.

Docket No. 32758, Application of AEP Texas Central Company for a Competition Transition Charge Pursuant to P.U.C. Subst. R. 25.263(n),  
Subject: Competitive Transition Charge.

Docket No. 32795, Staff's Petition to Initiate Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA § 39.253(f),  
Subject: Stranded Costs Allocation.

Docket No. 32907, Application of Entergy Gulf States, Inc. for Determination of Hurricane Reconstruction Costs,  
Subject: Cost Allocation.

Docket No. 32766, Application of Southwestern Public Service Company for: (1) Authority to Change Rates; (2) Reconciliation of its Fuel Costs for 2004 and 2005; (3) Authority to Revise the Semi-Annual Formulae Originally Approved in Docket No. 27751 Used to Adjust its Fuel Factors; and (4) Related Relief,  
Subject: Cost Allocation/Rate Design.

Docket No. 33586, Application of Entergy Gulf States, Inc. for a Financing Order,  
Subject: Financing Order Allocation.

Docket No. 32710, Application of Entergy Gulf States, Inc. for Authority to Reconcile Fuel and Purchased Power Costs,  
Subject: Capacity Rider Allocation.

Docket No. 31461, Application of AEP Texas North Company for a Competition Transition Charge Under to Subst. R. §25.263(N),  
Subject: Competition Transition Charge.

Docket No. 32795, Staff's Petition to Initiate a Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA § 39.253(f),  
Subject: Stranded Cost Allocation.

Docket No. 33309, Application of AEP Texas Central Company for Authority to Change Rates,  
Subject: Rate Design and Energy Efficiency Costs.

Docket No. 33310, Application of AEP Texas North Company for Authority to Change Rates,  
Subject: Energy Efficiency Costs and Riders.

Docket No. 32902, CenterPoint Energy Houston Electric, LLC Compliance Tariff,  
Subject: Allocation of Stranded Costs.

Docket No. 34077, Joint Report and Application of Oncor and EFH Pursuant to § 14.101,  
Subject: Leveraged buyout of utility.

Docket No. 35105, Compliance Tariff Filing of AEP Texas,  
Subject: Allocation of Stranded Costs.

Docket No. 35038, Texas-New Mexico Power Company Tariff Filing in Compliance with the Final Order in Docket No. 33106,  
Subject: Allocation of Stranded Costs.

Docket No. 34800, Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs,  
Subject: Cost Allocation & Rate Design.

\*Docket No. 37482, Application of Entergy Texas for a PCRF,  
Subject: Purchase Power.

\*Docket No. 37744, Application of Entergy Texas, Inc. for Authority to Change Rates,  
Subject: Cost allocation, rate design, proposed riders, & storm damage expense.

\*Docket No. 38951, Application of Entergy Texas, Inc. for Approval of CGS Tariff,  
Subject: Rate Design, Competitive Tariffs

\*Docket No. 42454, Application of SPS for Revision of EECRF<sup>1</sup>  
Subject: Recovery of energy efficiency costs

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<sup>1</sup> Asterick (\*) denotes testimony for Texas OPC as a consultant.

<b>TESTIMONY ON BEHALF OF STEERING COMMITTEE OF ONCOR CITIES</b>	Docket No. 35634,	<u>Re Oncor Electric Delivery’s Request for an Energy Efficiency Cost Recovery Factor,</u>
	Subject:	Energy Efficiency Cost Recovery.
	Docket No. 36958,	<u>Application of Oncor Electric Delivery Company LLC for 2010 Energy Efficiency Cost Recovery Factor,</u>
	Subject:	Energy Efficiency Cost Recovery.
	Docket No. 39375,	<u>Application of Oncor Electric Delivery Company LLC for 2012 EECRF,</u>
	Subject:	Energy Efficiency Cost Recovery.
<b>TESTIMONY ON BEHALF OF ALLIANCE OF XCEL MUNICI- PALITIES</b>	Docket No. 35664,	<u>Application of SPS to Revise Interruptible Credit Option Tariff,</u>
	Subject:	Interruptible Rate Avoided Costs.
	Docket No. 35763,	<u>Application of SPS to Change Rates and Reconcile Fuel and Purchased Power Costs,</u>
	Subject:	Energy Efficiency, Renewable Energy Credits, Power Cost Credits, and Interruptible Credits.
	Docket No. 37173,	<u>Petition for Declaratory Order of Southwestern Public Service Company Regarding the Generation Demand Charge as a Cap on Compensation for Interruptible Resources</u>
	Subject:	Interruptible Curtailable Option (“ICO”).
	Docket No. 43695,	<u>Application of SPS to Change Base Rates.</u>
	Subject:	Cost Allocation / Rate Design/ Jurisdictional
<b>TESTIMONY ON BEHALF OF CERTAIN TNMP CITIES</b>	Docket No. 36025,	<u>Application of TNMP for Authority to Change Rates,</u>
	Subject:	Cost Allocation and Rate Design.
	Docket No. 39362,	<u>Application of TNMP for 2012 EECRF</u>
	Subject:	Energy      Efficiency      Cost      Recovery

<b>TESTIMONY ON BEHALF OF PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE</b>	Docket No. R-2010-2161575, et. al.,	<u>PECO Energy Co.-Electric Division Base Rate Case,</u>
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2010-2179522,	<u>Duquesne Light Company Base Rate Case,</u>
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-248745,	Met Edison General Base Rate <u>Case,</u>
	Subject:	Cost Allocation and Rate Design.
<b>TESTIMONY ON BEHALF OF BEHALF OF GULF COAST COALITION OF CITIES</b>	Docket No. R-2014-2478743,	<u>Penelec Power General Base Rate Case,</u>
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-2478744,	<u>Penn Power General Base Rate Case,</u>
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2014-248752,	<u>West Penn Power General Base Rate Case,</u>
	Subject:	Cost Allocation and Rate Design.
<b>TESTIMONY ON BEHALF OF SWEPCO CITIES</b>	Docket No. 38339,	<u>Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates,</u>
	Subject:	Cost Allocation, Rate Design, Riders.
<b>TESTIMONY ON BEHALF OF ST.LAWRENCE COTTON GROWERS</b>	Docket No. 40443,	<u>Application of SWEPCO for Rate Change.</u>
	Subject:	Cost Allocation, Rate Design, Fuel Rule, Revs.
<b>TESTIMONY ON BEHALF OF ST.LAWRENCE COTTON GROWERS</b>	Docket No. 41474,	<u>Application of Sharyland Utilities for Unbundled Delivery Rates.</u>
	Subject:	Cost Allocation, Rate Design, Unbundling.

**TESTIMONY ON** Docket No.41987 Complaint Against Live Oak Resort  
**BEHALF OF LIVE**  
**OAK TENANTS** Subject: Sub Metering Complaint Case

**TESTIMONY FOR** Docket No.14-05-06 CL&P Rate Increase Application  
**CONNECTICUT**  
**CONSUMER COUNSEL** Subject: Cost Allocation, Rate Design, Decoupling

**TESTIMONY FOR** Docket No.44572 Centerpoint Application for DCRF  
**TEXAS COAST**  
**UTILITIES COALITION** Subject: Distribution Cost Recovery Factor

**TESTIMONY FOR** Docket No.44941 El Paso Electric Rate Case  
**CITY OF EL PASO** Subject: Class Cost Allocation; Rate Design

## Non Nuclear Decommissioning (\$/kW)

	AE	PUC Approved	Difference	Percent
Decker	38	17	21	55.3%
FPP	50	39	11	22.0%
Sand Hill	39	20	19	48.7%

	Requested Expense	Reduction	Allowed
Decker	\$ 14,000,000	\$ 7,736,842	\$ 6,263,158
FPP	\$ 3,750,000	\$ 825,000	\$ 2,925,000
Sand Hill	\$ 1,692,308	\$ 824,458	\$ 867,850
Total	\$ 19,442,308	\$ 9,386,300	\$ 10,056,008



## Production Demand Allocation Factors

	Residential	S1	S2	S3	P1	P2	P3
<b>BIP-N</b>	35.990%	2.012%	21.459%	20.223%	4.060%	4.794%	9.375%
<b>BIP-R</b>	35.351%	2.027%	21.449%	20.393%	4.090%	4.927%	9.601%
<b>Adj. A&amp;P-12CP</b>	35.312%	2.041%	21.451%	20.409%	4.069%	4.939%	9.610%
	T1	T2	Street L.	Outdoor L.	Cust. L.	Meter L.	Total
<b>BIP-N</b>	0.138%	1.623%	0.220%	0.077%	0.011%	0.019%	100%
<b>BIP-R</b>	0.150%	1.659%	0.239%	0.083%	0.012%	0.020%	100%
<b>Adj. A&amp;P-12CP</b>	0.152%	1.658%	0.243%	0.084%	0.012%	0.020%	100%

**Filed Rev Requirement With ICA Allocation Changes**  
*INCLUDES FUEL, PASS-THROUGHS*

	Total Retail	Residential		S1	S2	S3	P1	P2	P3
Rate Revenue	1,234,701,609	474,062,283		31,458,282	283,339,669	238,491,828	46,257,714	52,185,478	89,945,727
Cost of Service	1,217,227,310	475,622,876		31,259,261	249,588,917	237,774,156	46,552,743	54,188,915	99,923,374
Difference	(17,474,299)	1,560,593		(199,021)	(33,750,752)	(717,673)	295,029	2,003,437	9,977,647
Req Incr (Decr)	-1.4%	0.3%		-0.6%	-11.9%	-0.3%	0.6%	3.8%	11.1%
		T1		T2	Street L.	Outdoor L.	Cust. L.	Meter L.	Total
Rate Revenue		\$ 2,146,390	\$	13,517,421	\$ -	\$ 2,884,834	\$ 108,555	\$ 303,428	1,234,701,609
Cost of Service		\$ 1,777,803	\$	15,969,971	\$ -	\$ 4,046,523	\$ 141,145	\$ 381,627	1,217,227,310
Difference		\$ (368,586)	\$	2,452,550	\$ -	\$ 1,161,689	\$ 32,590	\$ 78,199	(17,474,299)
Req Incr (Decr)		-17.2%		18.1%		40.3%	30.0%	25.8%	-1.4%

Base Revenue CCOS Results With ICA Recommendation

	Total Retail	Residential	S1	S2	S3	P1	P2	P3
Base Revenue	631,878,463	257,323,175	19,088,191	155,631,706	116,217,584	19,269,437	22,527,463	33,982,914
Cost of Service	\$ 592,954,232	\$ 249,513,439	\$ 18,540,995	\$ 118,016,525	\$ 111,621,139	\$ 18,786,193	\$ 23,553,322	\$ 42,100,053
Difference	\$ (38,924,231)	\$ (7,809,736)	\$ (547,196)	\$ (37,615,180)	\$ (4,596,445)	\$ (483,245)	\$ 1,025,858	\$ 8,117,139
Req Incr (Decr)	-6.2%	-3.0%	-2.9%	-24.2%	-4.0%	-2.5%	4.6%	23.9%
		T1	T2	Street L.	Outdoor L.	Cust. L.	Meter L.	Total
Rate Revenue		1,328,468	\$ 3,970,086	\$ -	\$ 2,316,693	\$ 44,617	\$ 178,130	631,878,463
Cost of Service		\$ 919,567	\$ 6,122,357	\$ -	\$ 3,454,600	\$ 74,193	\$ 251,849	592,954,232
Difference		\$ (408,901)	\$ 2,152,272	\$ -	\$ 1,137,907	\$ 29,576	\$ 73,719	(38,924,231)
Req Incr (Decr)		-30.8%	54.2%		49.1%	66.3%	41.4%	-6.2%

## Modifications to AE CCOS Model

Sheet	Column	Row	Subject
WP D-1	O	144	reduce uncollectibles
WP D-1	O	17	reduce decommissioning
WP D-1	O	27	revenue imputation (a)
WP D-2	K	8	A&G 920 allocation
WP E-4	I	11	functionalize 311 expense
WP E-5.1	I	55	functionalize service connect. revenues
Sch. F-6	B thru Q	58 - 63	Insert new class allocators
Sch. G-2	F	27	revenue imputation (a)
Sch. G-4	F	184	sub functionalize 311 expense
Sch. G-4	F	696	sub functionalize A920
Sch. G-6	G	15	revenue imputation (a)
Sch. G-6	G	9 thru 14	BIP allocation
Sch. G-6	G	46 - 49	Distribution allocation
Sch. G-6	G	54	Meter allocation
Sch. G-6	G	64 - 67	Customer allocation

(a) The AE model provided no revenue imputation lines. The revenue imputation was reflected as a negative expense based on an unused expense account.

**ICA Proposed Distribution of Revenue Decrease**

	Total Retail	Residential	S1	S2	S3	P1	P2
Base Revenue	631,878,463	257,323,175	19,088,191	155,631,706	116,217,584	19,269,437	22,527,463
kWh Percent	100%	34%	2%	22%	21%	4%	5%
Rev Decrease	\$ (41,076,503) \$	(14,131,615) \$	(852,538) \$	(8,991,392) \$	(8,745,596) \$	(1,780,688) \$	(2,211,103)
	-6.5%	-5.5%	-4.5%	-5.8%	-7.5%	-9.2%	-9.8%
	P3	T1					
Base Revenue	33,982,914	1,328,468					
kWh Percent	10%	0.2%					
Rev Decrease	\$ (4,289,024) \$	(74,546)					
	-12.6%	-5.6%					

Notes:  
Assumes \$2.08 Mil rev increase for T2 for calculation purposes.  
No rate change for lighting classes.

**ICA Residential Customer Charge Calculation**

Meters	\$	13,569,411
Customer Accounting	\$	24,600,367
Customer Service	\$	9,572,309
Meter Reading	\$	14,741,815
Uncollectible	\$	-
Key Accounts	\$	12,461
Services	\$	(195,771)
Exclude GFT from Exp.	\$	(6,849,773)
Exclude A&G Expense	\$	(12,202,382)
Total	\$	43,248,437
Residential Bills		4,626,216
	\$	9.35