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

AUSTIN ENERGY'S EXCEPTIONS TO THE IMPARTIAL HEARING EXAMINER'S REPORT

July 22, 2016

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AUSTIN ENERGY'S EXCEPTIONS TO THE IMPARTIAL HEARING EXAMINER'S REPORT

TO THE HONORABLE IMPARTIAL HEARING EXAMINER:

COMES NOW, Austin Energy ("AE") and files these Exceptions to the Impartial Hearing Examiner's Report ("Report") issued July 15, 2016 in the above referenced proceeding.

I. INTRODUCTION

Austin Energy commends the Impartial Hearings Examiner ("IHE") on a well-developed, 299-page Report that comprehensively sets out the issues in this proceeding in a clear and cohesive manner. While Austin Energy does not agree with all of the recommendations of the IHE, continuing to follow the established process, in conjunction with the hours of public hearings scheduled by the City Council, can lead to an excellent result for the Greater Austin community that will be in all customers' interest.

Austin Energy proposes a $24,558,868 base rate reduction that strikes an appropriate balance among competing objectives of ensuring the long-term financial stability of the City-owned utility, achieving the Council's goals for affordability and efficient use of energy and charging each customer class the costs of providing them electric service. By comparison, adoption of the IHE's recommendations would result in a base rate reduction of $63,586,769. The $39,027,901 difference in the recommendations is attributable to the following six disallowances proposed by the IHE:[1]

[1] The disallowances to non-nuclear decommissioning expense, wholesale transmission revenue, uncollectible expense (bad debt), economic development expense, and rate case expenses each have an impact on the level of reserve funding which is also depicted on the chart.

Item	AE Recommendation	IHE Recommendation	Difference
Non-Nuclear Decommissioning Expense	$19,442,308	$17,792,850	-1,649,458.00
Wholesale Transmission Revenue	$62,129,919	$74,300,000	-$12,170,081
Uncollectible Expenses (bad debt)	$16,054,751	$10,199,660	-$5,855,091
Economic Development Expenses	$9,090,429	$0	-$9,090,429
Rate Case Expenses	$585,977	$370,644	-$215,333
Reserves Adjusted for Non-Nuclear Decommissioning	$11,590,703	$8,909,588	-$2,681,114
Reserves Adjusted for Bad Debts, EDD & Rate Case Expenses	$8,909,588	$6,376,528	-$2,533,061
$14.5 million Received from Sale of ECC Property (3rd & West Avenue).	$6,376,528	$1,543,194	-$4,833,333
		Total	($39,027,901)

Each of these adjustments is discussed in this filing.

Most significant among these adjustments is the IHE's recommendation to offset AE's retail revenue requirement by transmission revenues. AE's wholesale transmission and retail functions are separate operations that serve two distinct and different set of customers, have separate costs and revenues and are regulated by two different regulatory bodies. Given this separation, the rates for each of the functions are set independent of each other with wholesale and retail customers paying only for costs to serve their respective services. Adoption of the IHE's recommendation would lead to an unlawful subsidization by transmission customers throughout the Electric Reliability Council of Texas ("ERCOT"). By proposing a direct under-recovery of retail costs and then funding the short fall with wholesale transmission revenues, the IHE has effectively conducted a transmission cost of service ("TCOS") proceeding. Not only is this outside the scope of issues in this proceeding,[2] it is also beyond the jurisdiction of the Austin City Council. Furthermore, reducing retail rates simply by reflecting transmission revenues at a given point in time without any examination of transmission costs is poor ratemaking and establishes a bad precedent for transmission owning municipally-owned utilities ("MOUs")

[2] *See* Issue Outside the Scope of the Rate Review Process number 3 in Impartial Hearing Examiner's Memorandum No. 11 at 4 (March 11, 2016).

throughout the state. In contrast, AE's position is based on basic rate making principals of cost causation and cross subsidization and the law. Accordingly, AE urges the IHE to reconsider and reverse his recommendation on this issue.

In addition to the revenue requirement issues, AE respectfully requests that the IHE reconsider his recommendations on the following five cost allocation and policy issues: (1) Functionalization of the 311 Call Center, (2) Transformers and Capacitors, (3) Uncollectible Expense Allocation, (4) Allocation of Energy Efficiency Service Charge, and (5) Funding the outside-city discounts. Finally, this pleading seeks clarification or corrections on several issues that are discussed below.

Austin Energy appreciates the IHE's invitation to submit this brief. Although it is styled as "Exceptions," in truth it is akin to a motion for reconsideration. As such, Austin Energy appreciates the IHE's thoughtful reconsideration of Austin Energy's position and respectfully requests the IHE revise his position on a limited number of issues discussed herein.

II. REVENUE REQUIREMENT

B. Decommissioning Funding

AE's non-nuclear fleet consists of Decker Creek Power Station ("Decker"), Fayette Power Plant ("FPP"), and Sand Hill Energy Center ("SHEC"). AE proposes to add $19.4 million of additional revenue to cover future decommissioning expenses.[3] Of the total, $14 million is for the retirement of Decker, $3.75 million for the retirement of AE's portion of FPP, and $1.7 million toward the retirement of SHEC. The IHE recommends reducing the proposed decommissioning funding for FPP and SHEC by a combined $1,649,458.[4] The basis for the

[3] Austin Energy's 2015 Cost of Service Study and Proposal to Change Base Electric Rates, AE Ex. 1 at 857 (WP D-1.2.5).

[4] Although the IHE states that the adjustment is $3,792,850 at pages 5 and 28 of the Report, a review of the discussion, as well as summing the specific amounts recommended indicate that the actual disallowance is $1,649,458.

disallowance is that the benchmarking analysis taken from actual costs of decommissioning similar power plants for FPP and SHEC, rather than a site specific analysis, is insufficient and the "high estimates" presented by AE.[5]

AE is mindful of the desire to place less of a burden on ratepayers today. However, the uncertainty of the costs given the time horizon for retiring FPP and SHEC, the fact that funding is just now beginning despite the plants being in operation for many years, as well as the City's experience in decommissioning the Holly Street Plant all support adoption of the $19.4 million figure proposed by AE. Otherwise, there exists the very real possibility that future customers will bear an inequitable burden when the time for decommissioning arrives. Furthermore, should the actual costs end up being lower than expected, AE can apply the balance to funding decommissioning activities of other facilities and reduce required revenues in the next retail rate review.[6] Notably, non-nuclear decommissioning reserves are restricted for use in decommissioning Decker, FPP, and SHEC. When units at these plants are decommissioned, available funds will be used to offset actual costs. If actual costs exceed the funds accrued, additional revenues from rate increases will be required. In contrast, to the extent that actual costs are less than the funds accrued, funds can be applied to other non-nuclear decommissioning projects and allow for future revenue requirement reductions.

The cost estimates for each of the three plants were developed and reported by NewGen Strategies and Solutions ("NewGen") in a July 2015 study which examined the entirety of AE's reserve funds and policies.[7] The decommissioning costs of FPP and SHEC were based on a benchmarking analysis of scaled costs from actual costs for decommissioning similar power

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[5] Impartial Hearing Examiner's Report at 31 (July 15, 2016) ("Report").

[6] City Council policy requires a review of retail rates at least once every five years. The latest the next retail rate review would begin would be 2020, using an historical test year of 2019. *See* Financial Policy No. 17 in AE Ex. 1 at 371.

[7] AE Ex. 1 at 427-592.

plants, reported on a dollar per kW basis and then applied to the specific capacity of each unit at FPP and SHEC. Although the IHE expressed concerns that a benchmarking analysis by itself is not sufficient to support a recommendation establishing the cost to decommission FPP and SHEC, given the length of time before these plants are decommissioned, use of the study is appropriate and yields reasonable estimates.

The IHE also expressed concerns that the estimates presented by AE were "high."[8] These concerns were based upon Independent Consumer Advocate ("ICA") Witness Clarence Johnson's criticisms that the decommissioning cost estimates for exceeding average benchmarked costs for each of the three plants.[9] According to Mr. Johnson, these higher than average cost estimates are due in part to the treatment of contingency funds for each of the three plants.[10] Mr. Johnson observes that the contingency amount included within the decommissioning cost estimates were 30% for FPP and SHEC. Further, the 30% contingency for FPP and SHEC only applied to demolition costs, and not recycling and salvage offsets. These contingency levels reflect the significant uncertainty revolving around decommissioning FPP and SHEC; namely, the dates of decommissioning and the fundamental, underlying market conditions that will impact the ultimate cost to decommission the units are inherently unknowable today. Reflecting these uncertainties and relying on high level estimates result in a reasonable amount of funds to be collected for a future activity. Given these high level estimates, a 10% contingency would not reasonably reflect the uncertainty inherent in the analysis. Similarly, it is appropriate to apply the 30% contingency to the demolition costs for FPP and SHEC, because unknown or unidentified costs are a more significant concern than potentially understated salvage revenues in the way this analysis was developed. Moreover, the

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[8] Report at 31.

[9] Post-Hearing Brief of the Independent Consumer Advocate at 11-12 (June 10, 2016) ("ICA Brief").

[10] *Id.* at 12.

approved commission data validated the cost estimates developed for FPP and SHEC under a benchmarking approach. Thus, the amounts used by AE for decommissioning are appropriate.

At pages 31-32, the Report notes that a related issue is whether the decommissioning costs should be treated as an operations and maintenance ("O&M") expenses, or as a reserve amount. In the summary to the Report, the IHE states that the costs "are to be treated as reserves and not as an O&M expense."[11] This same comment is found at page 114 of the Report. However, the IHE does not make a recommendation or discuss the issue in the body of the Report. As a result, it is unclear what the IHE's recommendation is or the basis of his recommendation. The IHE suggests that the main concern with treated decommissioning costs as an O&M expense is the potential for AE to collect reserves related to decommissioning twice: once through the O&M expense and a second time through the reserve funds that are established based on a percentage of non-power supply O&M expense.

AE's evidence demonstrated that decommissioning costs should be treated as an annual O&M expense to be moved to a reserve fund for use when decommissioning activities begin. AE's method is consistent with the accounting treatment of nuclear decommissioning reserves and results in a funded liability on the balance sheet. AE's approach results in better alignment between the customers benefiting from the power plants while they are in service and the customers paying for the eventual dismantlement of the facilities in the future.[12] In the alternative and to address what appears to the IHE's driving concern, AE recommends that decommissioning costs continue to be collected as an O&M expense but that the costs be specifically and clearly removed from the reserve fund calculations.[13] This will ensure that Austin Energy doesn't increase base rate revenue requirements unintentionally.

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[11] Report at 10.

[12] AE Ex. 1 at 487.

[13] In fact, AE has used this alternative as the basis for the IHE's COS model posted on July 20, 2016.

In conclusion, fully funding the decommissioning reserve is the best way to mitigate intergenerational concerns going forward. The flow of potential excess funding to the next decommissioning project is reasonable given the fact that AE has not started collecting decommissioning funds for plants that have been in service for a decade or more. This structure allows current customers, who have benefited from the use of AE's current generation fleet, to bear some of the cost responsibility of the decommissioning expenses associated with those assets. For these reasons, Austin Energy requests that the IHE recommend that Council adopt the decommissioning reserve levels proposed by Austin Energy.

D. Transmission Costs and Revenues

The Report proposes to offset Austin Energy's retail revenue requirement by $74.3 million of transmission revenues without any discussion of the legal barriers, no examination of the appropriateness of the adjustment, and no examination of AE's TCOS. This translates into a disallowance of $12,170,081 to Austin Energy's retail base rates. Indeed, the only analysis in the Report focuses on the correct number to use to offset retail rates and an incorrect rejection of the fact that there is a distinction between Austin Energy's retail and wholesale operations. Instead, the Report simply reduces AE's retail rates by the amount of wholesale transmission revenue contained in Austin Energy's 4th Quarter FY 2014-2015 Report of Expected Revenue.[14] This is analogous to reducing *distribution* rates for an investor owned utility each year when it files an earnings monitoring report if its earned return for its *transmission* operations were different from the return approved in the utility's last rate case.

[14] Adoption of the Report's recommendation on this issue is analogous to reducing *distribution* rates for an investor owned utility each year when it files an earnings monitoring report if its earned return for its *transmission* operations were different from the return approved in the utility's last rate case.

Under Texas law, the Commission has exclusive authority to regulate transmission service.[15] As such, City Council does not have the legal authority to require wholesale transmission customers to subsidize AE's retail operations. Moreover, §§ 35.004(b) and (c) of the Public Utility Regulatory Act ("PURA") make it clear that a transmission service may not subsidize a MOU's retail function. This same prohibition is contained in Commission Substantive Rule § 25.275(o)(1)(C). Under the IHE's recommendations, revenues from transmission rates would cross subsidize AE's generation activities (i.e., retail rates include generation costs) which are competitive energy-related activities.[16] This plainly violates the Commission's rule.

At page 62 of the Report it states that the IHE does not find persuasive the distinction Austin Energy draws between its "retail transmission costs" from its "wholesale revenue."[17] It goes on to say that "Austin Energy's transmission assets were built for the benefit of Austin Energy's ratepayers."[18] This is incorrect. Transmission assets are built for the benefit of all those entities within the ERCOT market that use the transmission system, not simply for Austin Energy's ratepayers. This distinction is important because it demonstrates the separation between AE's wholesale transmission function and its retail function. Like many utilities in the state, AE has a transmission business and a retail business. Thus, AE is both a transmission service provider ("TSP") and a load serving entity ("LSE"). AE could divest itself of their entire transmission business and still be a LSE. Similarly, it could sell off its entire retail customer base and remain as a TSP. These functions serve two distinct and different set of customers,

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[15] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 35.004, 35.005 (West 2016) (PURA).

[16] AE assumes that if adopted, NXP/Samsung's proposal would be applicable both ways. That is, NXP/Samsung would support retail customers subsidizing the transmission function if it becomes necessary to increase transmission rates.

[17] Report at 62.

[18] *Id.*

have separate costs and revenues and are regulated by two different bodies. The rates for each of the functions are set independent of each other.

As noted, subsidization between AE's two functions is prohibited by law. Rates charged within each specific function must stand on their own merits. Wholesale customers should only pay for the costs to serve them just as retail customers should. Retail customers should neither receive subsidies from nor pay subsidies to wholesale customers and vice versa. In fact, in setting wholesale transmission rates, the Commission's rate filing package is predicated on specifically identifying and including only those costs and other revenues associated with the wholesale transmission function. The Commission specifically prohibits any cost of service elements from the retail function (costs and revenues) to be included in setting wholesale transmission rates. Importantly, AE adhered to the same exercise of deliberately removing wholesale transmission expenses and revenues from its base retail rate cost of service study in order to avoid any unwarranted impact on retail rates. This is amply reflected in the approximately $5 million adjustment AE made to its wholesale transmission expenses so that the only transmission-related expense remaining in the retail cost of service study was the expense related to retail transmission expense (FERC 565).

As discussed above, there is a difference between retail transmission expense and wholesale transmission costs. Wholesale transmission costs and retail costs are separate and distinct, recovered from two different customer bases, and under different jurisdictional ratemaking regulatory bodies. Consequently, the wholesale transmission function and the retail function should not subsidize each other. Keeping retail costs and revenues separate from those of AE's wholesale transmission function ensures that each set of customers only pays for the cost to provide the respective service.

Including costs or revenues from one function in the other's revenue requirement violates two basic rate making principals: cost causation and cross subsidization. Consequently, AE adjusted the transmission costs in the retail case to include only those costs applicable to the retail function and excluded costs associated with the wholesale function which are recovered from ERCOT's distribution service providers ("DSPs"). Retail transmission costs are recorded in FERC 565.[19]

As previously stated, AE made specific adjustments to the revenue requirement in order to exclude wholesale transmission costs and leave only retail transmission (matrix expense) recorded in FERC 565. Wholesale transmission revenue is set so that mathematically, the only remaining transmission expense included in the retail revenue requirement is the retail transmission expense in FERC 565, as shown at line 36, Column L, in Schedule A. The calculation is repeated below for clarity:

[19] Rebuttal Testimony of Russell H. Maenius, AE Ex. 8 at 8:3-9.

Line	Description	Schedule A, Column L	Retail	Wholesale	Total
1	Non-Fuel O&M	145,698,897	116,855,952	28,842,945	145,698,897
2	Depreciation & Amortization	16,333,280		16,333,280	16,333,280
3	Debt Service	17,933,287		17,933,287	17,933,287
4	General Fund Transfer	7,561,714		7,561,714	7,561,714
5	Internally Generated Funds for Construction	10,364,686		10,364,686	10,364,686
6	Depreciation & Amortization	(16,333,280)		(16,333,280)	(16,333,280)
7	Interest and Dividend Income	(890,025)		(890,025)	(890,025)
8					
9	Embedded Transmission COS components - Retail	180,668,558	116,855,952	63,812,606	180,668,558
10					
11	Less Other Non-Operating Transmission Revenue-wholesale COS (Schedule E-5, Row 4, Col L)	(1,682,688)		(1,682,688)	(1,682,688)
12					
13	Sub-total	178,985,870	116,855,952	62,129,919 [1]	178,985,870
14					
15	Adjustement to remove wholesale transmission COS	(62,129,919)		(62,129,919) [2]	(62,129,919)
16					
17	Retail Transmission Costs (FERC 565)	$ 116,855,952	$ 116,855,952	$ -	$ 116,855,952
18					
19					
20					
21	Footnote				
22	[1] Wholesale Transmission COS components to be eliminated from Retail COS				
23					
24	[2] Adjustment to wholesale transmission revenue to remove wholesale transmission costs from retail costs				
25	FY2014 Wholesale Transmission Revenue	68,974,261	WP E-5.1, Line 6, Col A		
26	Less Transmission Wholesale COS components	(62,129,919)	Line 13 from above		
27					
28	Adjustment to Wholesale Transmission Revenue to eliminate wholesale COS components	6,844,343	WP E-5.1.1		

As depicted above, AE's test year wholesale transmission revenue equals the net wholesale transmission cost of service ("COS") components embedded in the retail revenue requirement. Wholesale transmission revenue was used as the mechanism to remove wholesale transmission COS components embedded in the retail revenue requirement. Consequently, the wholesale transmission revenue included in AE's revenue requirement is simply the sum of the wholesale transmission COS components (Line 13 above, "Wholesale" column) and not comparable to AE's actual wholesale transmission revenues. Wholesale transmission COS components were removed from the revenue requirement because PURA prohibits retail customers from benefitting from or subsidizing wholesale transmission COS as well as for other reasons already presented. AE's adjustment to wholesale transmission revenue mathematically leaves only retail transmission expense (FERC 565). No parties dispute that the costs in FERC 565 are the sole retail transmission expense that should be recovered from retail customers.

Furthermore, it is bad policy to set retail rates arbitrarily lower based upon wholesale transmission revenues at a given point in time. As soon as utility rates are set by the regulator, the revenues and expenses of the utility vary from those approved. The fact that transmission revenues are different than the amount approved in the last case does not mean that a TSP has "excess revenues" or is over-earning. In contrast, the IHE's recommendation that allows wholesale transmission revenue to subsidize retail costs is based on the faulty assumption that AE is over-recovering on TCOS. In fact, if one were to include the full measure of AE's wholesale transmission revenues, then it is appropriate that the full measure of AE's wholesale transmission costs also be encompassed, including the wholesale transmission return authorized by the Commission. Wholesale transmission revenue has a higher embedded Commission approved return than what is included in the retail case and should be recognized to match revenues to cost of service.

Description	Modified Schedule A, Column L	Retail	Wholesale
Non-Fuel O&M	145,698,897	116,855,952	28,842,945
Depreciation & Amortization	16,333,280		16,333,280
Total Expenses (before Return)	162,032,176	116,855,952	45,176,225
Return	18,636,382		18,636,382
Additional Return Authorized by PUCT (Note 1)	**37,323,872**		**37,323,872**
PUCT Approved Wholesale Return	**55,960,254**		**55,960,254**
Total Cost of Service	217,992,430	116,855,952	101,136,478
Less Other (Non-Rate) Revenue	(63,812,606)		(63,812,606)
Additional Wholesale Revenue (Note 2)	**(14,479,680)**		**(14,479,680)**
Total Other (Non-Rate) Revenue	**(78,292,287)**		**(78,292,287)**
Total Retail Electric Revenue Requirement	139,700,144	116,855,952 FERC 565	22,844,192

Note 1	
Schedule B, Col L, Line 14 (Transmission Rate Base)	372,819,810
Authorized PUCT Wholesale Transmission Return (Docket 42385)	15.01%
Wholesale Transmission Return	55,960,254

Note 2	
Wholesale Transmission Revenue (WP E-5.1.1, Col C, Line 4)	62,129,919
Wholesale Matrix Revenue, Docket No. 45382	76,609,599
Additional Wholesale Transmission Revenue	(14,479,680)

As shown on the chart above, the Commission approved a 15.01% return on rate base in AE's last TCOS proceeding. Therefore, Austin Energy is under-recovering on its wholesale transmission function by $23 million. By incorporating wholesale transmission costs and revenues into the retail case, as opposed to AE's position of eliminating wholesale transmission costs from the retail case, retail customers would be subsidizing AE's wholesale transmission function by $23 million.

Schedule A, Col L, Line 36	$116,855,952	Equals FERC 565 Amount
Additional retail revenue to subsidize wholesale function	+$22,844,192	
Modified Sch A to include all transmission wholesale costs/revenues	$139,700,144	

This depiction demonstrates that this retail case does not include all of the TCOS elements used to determine AE's TCOS revenue. Consequently, the presumption that there are excess TCOS revenues available to subsidize the retail revenue requirement is false since the IHE recommendation does not take into account all of the wholesale elements that TCOS revenues pay for. Moreover, if the full breadth of wholesale transmission expenses and revenues are included in this retail cost of service study, *retail customers* would be subsidizing wholesale customers by contributing additional revenue to make up for AE's wholesale transmission under-recovery. This is as unfair to retail customers as requiring wholesale customers to subsidize retail customers.

By proposing a direct under-recovery of retail costs and then funding the short fall with wholesale transmission revenues, the IHE has effectively made a TCOS determination that is outside the scope of issues in this proceeding, outside the regulatory scope of Austin City Council, and without due process. Specifically, the IHE recommendation results in a 5% return on rate base compared to the 15% return approved by the Commission for AE in June 2014. Stated differently, by under-recovering retail costs, then subsidizing the short fall with TCOS revenue, the IHE effectively has re-set TCOS rates to recover $12.1 million less than allowed by the PUC.

If the IHE supports the concept that the wholesale function should be allowed into determining retail rates, which is the underlying premise of the IHE's recommendation, then the retail revenue requirement must be increased by $23 million to allow full recovery of AE's

TCOS. Alternatively, if the IHE does not support the concept that the wholesale function should be allowed into determining retail rates, then the Report could be accused of "cherry picking" wholesale cost of service components.

In summary, the IHE's recommendation to reduce retail revenue requirements by using wholesale transmission revenue should be reversed for the following reasons:

- AE's wholesale transmission function and its retail function serve two distinct and different set of customers, have separate costs and revenues, and are regulated by two different bodies.
- The rates for each of the functions are set independent of each other, based only on the costs to provide the distinct and separate services to the respective customer base.
- Wholesale customers should only pay for the costs to serve them just as retail customers should. Retail customers should neither receive subsidies from nor pay subsidies to wholesale customers and vice versa.
- Subsidization between AE's two functions is prohibited by law.
- The recommendation effectively results in a new Transmission Cost of Service study which is exclusively in the regulatory purview of the PUC.
- Wholesale transmission revenues should be set to eliminate wholesale transmission costs included in the retail revenue requirement. The only transmission component in this retail case is the costs in FERC 565.
- The IHE's recommendation is based on the faulty premise that there are excess wholesale transmission revenues available to subsidize retail costs. The IHE has not taken into account all components of AE's TCOS and therefore cannot arrive at the conclusion that AE's wholesale transmission function is over-recovering.
- The recommendation supersedes the Commission to regulate the wholesale transmission function by effectively imposing TCOS rate reduction.
- It is bad public policy, and politically unwise to establish Austin Energy's retail base rates based upon assumptions about Austin Energy transmission function.

For these reasons, AE requests the IHE reverse his recommendation and keep transmission wholesale and retail rates separate.

G. Uncollectible Expense

The reasonable amount associated with uncollectible expense is $16,054,751.[20] This is a decrease of $4.8 million[21] from the actual uncollectible expense AE incurred in FY 2014. The IHE recommends an expense amount of $10.1 million based on a five-year average of uncollectible expenses between FY 2010 and FY 2014.[22] AE disagrees with this recommendation and requests the IHE reconsider his recommendation.

AE's concerns are two-fold. First, AE is concerned that while the amount of uncollectible expense decreased between FY 2014 to FY 2015, the trend may go the other direction. Specifically, AE is concerned that a different trend may emerge in the coming year because the amount of bad debt experienced in FY 2014 is in part attributable to a more lenient payment arrangement policy approved by the Austin City Council in Fall 2013.[23] More recently, in a May 2015 presentation to the Austin Energy Utility Oversight Committee, AE showed there were 2.7 times as many customers on payment arrangements in April 2015 than in April 2013 and that the amount due in payment arrangements had increased by 72%.[24] This data suggests that there is a distinct possibility that the level of uncollectible expenses may be on the rise again after a single year decrease.[25]

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[20] AE Ex. 1 at 383 (Schedule D-1, Column J, Row 138).

[21] *Id.* at 93.

[22] Report at 7.

[23] *See* City of Austin Code of Ordinances § 15-9-144, AELIC Ex. 36 and Tr. at 867:9-17.

[24] AE Response to AELIC RFI No. 10-13, AELIC Ex. 38 at 255.

[25] AELIC Witness Lanetta Cooper offered evidence from a June 2014 presentation by AE staff to the Austin City Council in AELIC Ex. 38. However, Ms. Cooper cherry picked information from AE's complete response to AELIC's RFI Nos. 10-12 and 10-13 to support her position. Had Ms. Cooper presented additional information provided in these responses using data from a more recent presentation to City Council, such as AE's May 28, 2015 presentation, a more complete picture of AE's uncollectible expense level would have been drawn in AELIC's Closing Brief.

Additionally, this recommendation does not meet the known and measurable test for making adjustments to historical financial data. A single year's financial performance is not an accurate indicator of future trends. The Report states that AE's adjustment appears to be based upon a one-year assessment, but that is incorrect. AE adjusted the test year amount to take into account two years of data and reflects more recent information. Consequently, AE's proposed $16 million of uncollectible expense is a reasonable estimation of future expenses as it reflects both historical and current trends and should, therefore, be adopted.

H. Economic Development and Community Programs

Austin Energy requests reversal of the IHE's recommendation that $9,090,429 associated with Austin Energy's share of the City's Economic Development Department be excluded from rates. According to the Report, these costs were disallowed because they "are not costs related to the provision of electric utility service."[26] Unfortunately, the Report provides no explanation or justification for this conclusion. Instead, it misinterprets a statement from AE's brief to conclude that comparisons to private, for-profit utilities "are of little relevance."[27] In fact, the opposite is true.

Historically, the Commission has approved economic development measures in both the form of economic development rates as well as through contributions to economic development programs. In doing so, the Commission has specifically noted "it is good public policy to

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[26] Report at 95.

[27] In the relevant section, at page 44 of its closing brief, AE was responding to arguments by the ICA suggesting that the *level* of AE's economic development expenditures were unreasonable because they represent a higher percentage of its revenue than CenterPoint's expenditures. As noted in brief, the ICA's comparison lacked context and is not an accurate indicator of what constitutes an appropriate amount for a utility to spend on economic development. In contrast, MOUs are the same as IOUs in terms of whether the expenditure is related to the provision of electric service. Significantly, the Commission has found that CenterPoint's economic development expenditures are related to the provision of electric service.

encourage economic development in Texas."[28] Further, the Commission has concluded that "[e]conomic development programs benefit all customers, either directly or indirectly"[29] because economic development benefits customers by spreading system costs over an increased number of customers.[30] For example, in a 1990 Houston Lighting & Power ("HL&P") rate case, the Commission concluded that the economic development of the Houston area was a desirable goal and that HL&P had a "legitimate role to play in encouraging that development."[31] Similarly, Austin Energy's funding of economic development and community programs is a reasonable and necessary expenditure that helps develop a diverse system load. A diverse system load benefits all customers by improving AE's system load factor and thus reducing regulatory costs. Economic development programs also lead to a more stable and predictable system load, and increase the customer base to share AE's fixed costs.

When Senate Bill 7 was passed in 1999 and electric utilities were unbundled, the Commission opened a rulemaking project to adopt new rules in order to implement PURA § 39.051 related to unbundling of electric utilities. When the Commission addressed competitive energy services in that project, it specifically considered economic development costs. While some commenters on the rule argued that it was inappropriate to allow electric utilities to engage in economic development or community support activities, the Commission expressed its belief

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[28] *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 41 (Oct. 14, 1998).

[29] *Application of TXU Electric Company for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344,* Docket No. 22350, Order at 165, Finding of Fact No. 161 (Oct. 4, 2001).

[30] *Application of Reliant Energy HL&P for approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344,* Docket No. 22355, Proposal for Decision at 166-67 (Mar. 28, 2001).

[31] *Application of Houston Lighting and Power Company for Authority to Change Rates; Application of Houston Lighting and Power Company for a Final Reconciliation of Fuel Costs Through September 30, 1988,* Docket Nos. 8425 and 8431, 16 P.U.C. BULL. 2582 at Finding of Fact No. 160 (June 20, 1990).

that electric utilities should be permitted to engage in limited economic development and community support activities.[32] The Commission concluded that activities intended to attract new business to the community are considered to be a benefit because "they increase the base over which a utility's costs are shared."[33] More recently, in Docket No. 38339, the Commission approved $3.395 million in economic development expenditures by CenterPoint.[34] The Commission approved similar expenditures by Oncor in Docket No. 35717. In each of these instances the Commission has found that the expenditures were reasonable and necessary for the provision of electric service. Moreover, they have specifically found that economic development benefits customers by spreading system costs over an increased number of customers.[35] This benefit exists regardless of whether the utility is an investor-owned utility ("IOU") or a MOU.

In summary, economic development and community programs expenses *are* reasonable and necessary for providing utility service. The Economic Development Department attracts new businesses to Austin, which creates new customers for AE, and helps retain and expand existing Austin businesses, thus maintaining and increasing revenue for AE. In addition to attracting new and retaining existing commercial customers, economic development programs lead to new residential load growth. For all of these reasons, AE requests the IHE recommend inclusion of the $9,090,429 associated with Austin Energy's share of the City's Economic Development Department in rates.

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[32] *Cost Unbundling and Separation of Utility Business Activities, Including Separation of Energy Services and Distributive Generation*, Project No. 21083, Order at 84 (Jan. 19, 2000).

[33] *Id.*

[34] *Application of CenterPoint Electric Delivery Company, LLC for Authority to Change Rates,* Docket No. 38339, Proposal for Decision at 148-149 (Dec. 3, 2010); Docket No. 38339, Direct Testimony of Daniel Hagen at Exhibit DOH-3 Page 30 of 35 (June 30, 2010).

[35] Docket No. 22355, Proposal for Decision at 166-167 (Mar. 28, 2001).

K. Rate Case Expense

Austin Energy proposes to collect rate case expenses over a three year amortization period. This compares to the five year amortization period recommended by the IHE.[36] As noted in Mr. Dombroski's rebuttal testimony, a three year amortization is typical of the period over which other utilities collect rate case expenses. This is reasonable because it balances the interests of the utility in obtaining cost recovery and the interests of ratepayers by mitigating rate impacts and spreading the cost over the period that rates are likely to be in effect. In contrast, a five year amortization is inconsistent with standard practice for utilities in Texas.

Additionally, AE's proposal avoids expense recovery from one proceeding overlapping with the recovery of expenses from a subsequent rate case. This is particularly important for AE because, although it has a financial policy to conduct a cost of service study at least every five years, the policy does not prohibit AE from conducting one on a shorter time frame. For these reasons, a three year amortization period for rate case expenses is the most appropriate and should be recommended.

M. Reserves

1. Reserve Funding

The IHE recommends one modification to Austin Energy's reserve funding proposals: "that funds associated with the decommissioning of Decker Units 1 & 2, FPP, and SHEC, are to be treated as reserves and not as an O&M expense."[37] Austin Energy's discussion of this issue is contained in Section II.B above.

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[36] Report at 106. At page 9 of the Report, the IHE correctly notes that recovering rate case expenses over a period of 5 years (instead of 3 years as proposed by Austin Energy) translates into a $215,333 reduction to Austin Energy's revenue requirements. This is depicted as follows: [($1,615,000/3) + 47,644] – [($1,615,000/5) + 47,644] = $215,333. At page 106, the Report incorrectly states that this is a $234,391 reduction.

[37] Report at 114.

2. Policies

Austin Energy recommends increasing the Working Capital Reserve to a minimum of 60 days of non-power supply costs in order to adequately account for Austin Energy's firm expense obligations associated with City transfers, including both shared services and the General Fund Transfer ("GFT"). These transfers are not considered when AE calculates the current 45-day target funding amount. Austin Energy recommends that there be a maximum limit on this reserve (*e.g.*, 90 days). At page 119 of the Report, the IHE disagreed with this proposal and recommends that the Working Capital Reserve be based upon 45 days of non-power supply costs.[38]

Although the IHE acknowledges the GFT is a "firm obligation" of AE's, he argues the GFT is not the type of expense "typically associated with cash working capital."[39] However, MOUs are different from investor owned utilities. AE's obligation to transfer funds associated with shared service and with the City's General Fund Transfer should be appropriately considered as firm, ongoing, and substantive cash requirements that the utility must meet each month. IOUs do not have this type of regular fund transfer and consequently, the Public Utility Commission's ("PUC" or "Commission") rules do not contemplate the impact these transfers might have on the utility's operating cash balances. In fact, the primary reason for AE's recommended change to 60 days of non-power supply O&M costs is to reflect this fundamental difference.

The GFT places the same claim on cash as an operating expense and cash reserves. As such, working cash reserves must be maintained in such a manner to reflect cash claims regardless of the nomenclature. Working Capital Reserve, like all reserve funds, provides a buffer in the event of disruption to revenues or other cash flow (e.g. extreme mild weather) or the

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[38] Report at 119.

[39] *Id.*

expense side (e.g. unexpected outflow of cash). Finally, bond rating agencies also treat the GFT as an "above the line" expense. Therefore, the cash requirement for items such as the GFT should be recognized by increasing the number of days utilized in the calculation. In summary, working cash reserves are appropriately based upon 60 days of non-power supply costs in order to reflect the cash claim of items such as the GFT.

N. Property Transfers

1. Energy Control Center

The IHE recommends that Austin Energy and Council should consider $14.5 million that AE received as a result of the sale of the Energy Control Center ("ECC") "as funds available to fund either Austin Energy's operations or its reserves."[40] AE takes exception with this recommendation. These funds represent a one-time, non-recurring, out-of-test-year receipt of monies which should not be considered in the current rate proceeding.

As noted in its Closing Brief, AE received the $14.5 million during the current fiscal year.[41] As such, considering the monies in this rate proceeding will create a rolling test year. The IHE purports to address this issue by concluding the transfer of funds was a known and measurable event for which AE should have taken a post-test year adjustment.[42] This course of action is imprudent. In order to establish some modicum of certainty for both the utility and the ratepayers, rates are set using the data from a test year. And while some known and measurable modifications are made to that test year data, such adjustments are not made for one-time, non-recurring funds, such as the $14.5 million at issue here.

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[40] Report at 127.

[41] Austin Energy's Closing Brief at 62, citing Tr. at 856:2–4 ("AE Closing Brief).

[42] Report at 126.

AE maintains its position that it has used the funds received from the transfer of the ECC to reduce the debt obligations incurred for the construction of the new Systems Control Center.[43] However, to avoid any confusion going forward, and in an attempt assuage the concerns expressed by Austin Energy Low Income Customers ("AELIC"), the ICA, NXP Semiconductors, Inc. and Samsung Austin Semiconductor, LLC ("NXP/Samsung"), and now the IHE, AE is exploring the feasibility of creating a separate sub-account within its existing account to provide more concrete proof that the funds are being used for debt service expenses related to the Systems Control Center. Additionally, the receipt of funds will be appropriately reflected during the next rate review proceeding and related cost of service update.

III. COST ALLOCATION

A. Functionalization of the 311 Call Center, FERC 920 Administration and General Labor Costs and New Service Connection Fees

1. Functionalization of the 311 Call Center

The costs of the 311 Call Center are driven by call volume, which best correlates with the number of customers. Additionally, the 311 Call Center provides a community benefit that should be distributed equally between customers. As a result, the 311 Call Center should be functionalized to customers and allocated to each rate class based on the number of customers in the class.

The IHE's recommendation to assign these costs to the distribution function is based upon the recommendation of ICA witness Johnson.[44] However, Mr. Johnson misinterpreted the use and benefit of the 311 system. Specifically, his proposal to functionalize the 311 Call Center to distribution and allocate these costs to rate classes using distribution O&M expense would

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[43] *See e.g.* Rebuttal Testimony of G. Canally, AE Ex. 5 at 8:7–11.

[44] Report at 138.

result in customers with larger demands paying a greater share of 311 Call Center costs compared to customers with smaller demands. This end result is inappropriate because the benefit associated with access and use of the 311 Call Center is the same for customers of all sizes.

Mr. Johnson's contention was that the disaster recovery portion of the 311 Call Center cost is presumably focused on restoring power service. However, he failed to account for the fact that these costs actually have nothing to do with grid operations. Emergency use of the Call Center is no different from normal use of AE's customer service center. In both cases, customers are able to call and report service interruptions, billing issues, or other concerns to AE and other City departments. The disaster recovery benefits of the 311 Call Center are associated with a remote site that can be used on a moment's notice to avoid disruption of availability. The 311 Call Center provides AE communications redundancy with the same underlying use and benefit as the customer service center.

For these reasons, costs associated with the 311 Call Center should be assigned to the customer function rather than to the distribution function as proposed in the Report. Accordingly, AE requests the IHE reverse the recommendation in the Report and assign 311 Call Center Costs to the customer function.

D. Classification and Allocation of Distribution Costs

1. Classification of Distribution Costs

(a) Transformers and Capacitors

At pages 173-74 of the Report, the IHE recommends that transformer costs be allocated on customer demand based on AE's 4NCP for the months of June through September, as proposed by NXP/Samsung.[45] Consistent with the widely accepted method at the Commission,

[45] Report at 173-74.

AE recommends these costs be allocated using the Sum of Maximum Demands ("SMD") method.[46]

To ensure reliability of service to customers, distribution transformers are sized to meet customer maximum demands on the system. These transformer costs are fixed, meaning that they do not vary with energy use. It is standard industry practice to classify transformers as demand related costs and allocate these costs on some measure of customer demand. As such, AE allocates these costs using the SMD method. SMD reflects the maximum monthly demand a customer places on the system during each month of the year.

The IHE's recommendation states that "these costs [should be allocated] on customer demand based on an AE's 4NCP for the months of June – September."[47] This recommendation does not address allocation of these costs to primary and transmission customers. Regardless of the methodology selected to allocate transformer costs, these costs should not be allocated to the primary and transmission classes since these customers own their infrastructure (i.e. transformers). Accordingly, AE requests clarification from the IHE indicating that it would be inappropriate to allocate transformer costs to these customers.

E. Allocation of Customer Service Costs

1. Uncollectible Expense Allocation

Uncollectible expense should be allocated using a direct assignment method. Directly assigning the cost to each rate class is a highly supportable and equitable method for recovering

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[46] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695 (Feb. 23, 2016); *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 41791 (May 16, 2014); *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896 (Nov. 2, 2012); *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 37744 (Dec. 13, 2010); *Application of CenterPoint Energy Houston Electric, L.L.C. for Authority to Change Rates*, Docket No. 38339 (June 23, 2011); *Application of Sharyland Utilities, L.P. to Establish Retail Delivery Rates, Approve Tariff for Retail Delivery Service, and Adjust Wholesale Transmission Rate*, Docket No. 41474 (Jan. 23 2014).

[47] Report at 163.

these costs from customer classes. As noted in Mr. Mancinelli's testimony, NARUC acknowledges that directly assigning these costs to each rate class is appropriate.[48] In addition, direct assignment comparisons conducted by Mr. Mancinelli demonstrated that the direct assignment method yields a stable result.

In contrast, the IHE recommends allocating uncollectible accounts to each rate class based on the class revenue requirement.[49] This is based upon the analysis submitted by ICA witness Johnson. In his direct testimony, Mr. Johnson suggested that the direct assignment approach could result in volatile results by class. However, AE Witness Mancinelli compared the direct assignments associated with uncollectible accounts included in the prior rate case (i.e. 2009) with that of the current rate filing package (i.e. 2014). The direct assignment comparisons demonstrated that the direct assignment method yields a stable result. This result is not surprising given the number of bills rendered and the underlying socioeconomic conditions of various rate classes. In addition, the Report notes that the direct assignment proposal was rejected by the Commission in an Entergy rate case (Docket No. 16705). However, that single, twenty year old decision, was specific to Entergy and does not discredit the appropriateness of AE using a direct assignment approach to allocating uncollectible expense.

F. Allocation of Energy Efficiency Service Charge

Following the filing of the Tariff Package on January 25, 2016, it became clear that the proposed energy efficiency service ("EES") rate would not ultimately meet AE's objective to reduce year-to-year interclass subsidies and therefore, it would not meet AE's desired cost causation outcomes. As such, AE filed the Rebuttal Testimony of Deborah Kimberly and

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48 Electric Utility Cost Allocation Manual, January 1992 at 102.

49 Report at 185.

proposed an adjustment to the EES fee which brought the rates closer to class cost of service and maintained one of AE's original objectives to provide year-to-year rate predictability.[50]

Nevertheless, the IHE recommends rejecting AE's proposed adjustment to the EES fee. According to the Report, the IHE is concerned that "AE provided no new cost of service study to support its proposal" and the "apparent lack of a concrete cost analysis."[51] The IHE is also concerned about the impact on the residential customers and troubled by "the element of surprise attendant to AE's new proposal."[52] AE will respond to each of these concerns.

As to the concern about the lack of cost analysis, AE's EES rate design proposal was based upon an evaluation of the program and is designed to better align costs with the customers responsible for those costs. Furthermore, AE recognizes that there is year-to-year variability in the proportion of benefits received by different rate classes. Therefore, AE proposes to allocate the EES program costs on a three-year rolling average of total EES costs, divided by the share of residential costs and non-residential costs. The non-residential rate will be adjusted for voltage. This allocation methodology will ensure that if, in the future, the ratio of benefits shifts from one group to another, the EES rate will reflect those changes and will assign the cost to the proper recipients.

As to the impact on residential customers, AE urges the IHE to consider the reasonableness of the rate design. In essence, the IHE should rule exclusively on the appropriateness of the allocation methodology and not on any potential rate that results from that allocation. Since this EES rate review is focused exclusively on the rate design and not the rate itself, AE's intent from the outset was to design a rate that met two objectives: (1) align more closely with costs; and (2) offer predictability for its customers. Not coincidentally, that revised

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[50] Rebuttal Testimony of Deborah Kimberly, AE Ex. 7 at 15:15-17:22.

[51] Report at 199.

[52] *Id.*

rate design is entirely consistent with the objectives stated throughout this rate review. Because the redesigned rates may shift more cost to the Residential class and reduce the costs to commercial classes, advocates for residential customers are vehemently opposed to the proposal. This is not a basis for rejecting a sound cost allocation methodology.

The IHE also expressed concern about the "lateness with which AE presented it proposal for reallocation of EES."[53] In response, AE notes that Public Citizen and Sierra Club ("PC/SC"), AELIC and ICA propounded several discovery questions on AE regarding the new EES rate. AE responded fully with more than 250 pages of documents to support the responses. The parties had more than a week to review three pages of rebuttal testimony related to the new EES rate design, were allowed to ask and received responses to discovery questions, had the opportunity to cross-examine three witnesses, and provided final arguments in their briefs. As such, parties had adequate time to analyze the proposed rate redesign. In summary, AE's proposal is reasonable, reflects cost causation principles, and is rooted in policy objectives that have been clear since the beginning of this rate review. Accordingly, AE recommends the IHE adopt the revised EES rate allocation methodology.

Finally, Austin Energy seeks clarification on two additional points related the IHE's recommendation that the "EES Charge should be a uniform charge assigned to all customer classes..."[54] First, in both the current and proposed rate, it is necessary to make adjustments to the non-residential rate to account for voltage. This results in the rates not being precisely uniform. No party challenged this adjustment. In fact, the IHE notes at page 196 of the Report that "Public Citizen and Sierra Club are supportive of a uniform EES fee for all customer classes, with a slight adjustment based on voltage...."[55] Second, large industrial customers in the P4 and

[53] Report at 198.

[54] Report at 199.

[55] Report at 196.

T2 rate classes do not have to contribute into the EES recovery pursuant to tariff design decisions already approved by the City Council. This is consistent with how EES charges are currently allocated. Austin Energy respectfully requests the IHE clarify his recommendation to account for these two issues.

IV. REVENUE DISTRIBUTION / ALLOCATION / SPREAD

V. RATE DESIGN

VI. VALUE OF SOLAR ("VOS") ISSUES

VII. POLICY ISSUES

A. Funding Discounts

At page 253 of the Report, the IHE recommends that Council "continue to fund the rate differential between outside-city rates and inside-city rates, from inside-city ratepayers."[56] This recommendation is consistent with AE's position. However, the Report goes on to that "funding of the discount be accomplished from all customer classes."[57] This recommendation was made without knowledge of how the discount is recovered or AE's proposed funding of the discount going forward.[58]

Austin Energy funds discounts by a separate tracking mechanism or by rolling the discount amount back into its prospective customer class.[59] With respect to the outside-city discounts, they are funded by inside-city customers that are in the same classes that receive a discount outside the city. Pursuant to the settlement in Docket No. 40627, outside-city customers in the Residential, S2, S3, P1 and P2 classes received a discount.[60] These same

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56 Report at 253.

57 Report at 256.

58 *Id.*

59 Rebuttal Testimony of Mark Dombroski, AE Ex. 2 at 12:14-16.

60 *Petition by Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-055*, Docket No. 40627, Stipulation and Settlement Agreement at 5-6 (Mar. 18, 2013).

classes fund the discounts inside the city in the same amount of the discount for each class. This is similar to how AE funds other discounts it provides a methodology which discourages additional inter-class subsidies. As noted in brief, although AE proposes several changes to the structure of some of its discounts, it does not propose changing the funding of its discounts.[61] As such, AE takes exception to the IHE's recommendation to change the funding for the following reasons.

First, the current funding methodology is the same as when the parties entered into the settlement of PUC Docket No. 40627 establishing the discount. AE has stated that the rationale for maintaining the Docket No. 40627 settlement agreement terms is not cost-based; rather, it reflects a risk mitigation strategy that is in the interest of inside city ratepayers.[62] Altering the funding of the discount would shift costs to other classes and change the methodology agreed to by the settling parties. Second, the method for funding the outside-city discounts is consistent with how AE funds other discounts. Stated differently, it is reasonable to fund the discount on an intra-class basis. Finally, the IHE recommends the discount be allocated to all customer classes in "the same manner in which AE's rate-case expenses are assigned to the various customer classes..."[63] Rate case expenses are allocated in a complicated and multi-step process that begins by functionalizing the costs to the production and distribution functions. The costs are then classified into demand, energy, or customer classifications. Lastly, they are allocated to all classes except the transmission classes. In the event the IHE decides to not alter his recommendation to fund the discount from all classes, AE posits that allocating the costs on a revenue requirement basis would be preferable because it is simple, straight-forward, and logical. In either instance, the costs would not be allocated to the transmission classes.

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61 AE's Closing Brief at 121.

62 *See, e.g.*, Rebuttal Testimony of Mark Dreyfus, AE Ex. 9 at 11:6-12; Tr. at 645:7-16.

63 Report at 256.

For the reasons, AE urges the IHE to reverse his recommendation and affirm continuation of the funding of the discounts to outside-city customers. In the alternative, AE requests the IHE recommend that the cost of the discount be allocated to the classes on a revenue basis rather than using the same manner in which rate case expenses are allocated.

VIII. STATEMENT OF POSITION / OTHER ISSUES

IX. CONCLUSION

In setting its base rates, Austin Energy entered into a deliberative process in order to receive public input. As part of that process, the City of Austin engaged the IHE to hear the evidence and make recommendations. Although Austin Energy does not agree with all of the IHE's recommendations, overall the Report is thorough and well-reasoned. It provides guidance to AE and the City Council on providing better service and reaching the proper outcome in this case.

Austin Energy extends its appreciation to the IHE for his thoughtful consideration of the evidence and patience with this process. Toward that end, Austin Energy has limited these Exceptions to identifying the key issues that warrant reconsideration by the IHE. Accordingly, it is respectfully requested that AE's Exceptions to the Report, as set forth above, be granted and such other and further relief to which it may be entitled.

Respectfully submitted,

LLOYD GOSSELINK ROCHELLE & TOWNSEND, P.C.
816 Congress Avenue, Suite 1900
Austin, Texas 78701
(512) 322-5800
(512) 472-0532 (Fax)
tbrocato@lglawfirm.com

THOMAS L. BROCATO
State Bar No. 03039030

ATTORNEY FOR THE CITY OF AUSTIN

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of this pleading has been served on all parties and the Impartial Hearing Examiner on this 22nd day of July, 2016, in accordance with the City of Austin Procedural Rules for the Initial Review of Austin Energy's Rates.

THOMAS L. BROCATO