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

AUSTIN ENERGY'S RESPONSE TO THE INDEPENDENT CONSUMER ADVOCATE'S EIGHTH REQUEST FOR INFORMATION

Austin Energy ("AE") files this Response to The Independent Consumer Advocate's ("ICA") Eighth Request for Information submitted on May 24, 2016. Pursuant to the City of Austin Procedural Rules for the Initial Review of Austin Energy's Rates § 7.3(c)(1), this Response is timely filed.

Respectfully submitted,

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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 31st day of May, 2016, in accordance with the City of Austin Procedural Rules for the Initial Review of Austin Energy's Rates.

HANNAH M. WILCHAR

ICA 8-1 Admit or Deny that Joe Mancinelli recommended, in a November 30, 2015 memorandum to Mark Dombroski, that AE's class cost of service study utilize the NARUC Cost Accounting method to classify and allocate production O&M expense.

ANSWER:

The November 30, 2015 memo was developed in response to an AE request asking NewGen to look at other cost of service methods used by electric utilities and recognized by PUCs that might relieve the residential class of some of its cost of service responsibility. At the time, AE was vetting cost of service results and was interested in other allocation approaches and the impact of these approaches on cost of service results. After discussion with AE on this subject, we agreed that the use of the NARUC Cost Accounting method was not appropriate for the following reasons:

1. The cost classification method initially recommended by NewGen and used in the RFP best reflects ERCOT market conditions.
2. Given changes to the wholesale electricity markets, pre-nodal market PUC precedent with respect to production cost classification cannot be uniformly relied upon without considering changes in the ERCOT market.

The production cost classification method used in the RFP is reasonable and consistent with recommendations NewGen personnel made regarding the proper classification of production costs made in the 2011 rate review. NewGen fully supports the production cost classification method used in the RFP as described by Mr. Mancinelli's rebuttal testimony.

Prepared by: JM
Sponsored by: Joe Mancinelli

ICA 8-2 Please provide a full explanation for the table on the bottom of page 8 (Dombroski Rebuttal). In particular, what is the impact of this change on inside city HOW customers' bills. Also, please provide the additional amount of revenue reduction attributable to the S2 and S3 classes as a result of correcting the billing determinant error

ANSWER:

In the rate design work papers, the rate year billing determinates were adjusted to account for the change in billed demand resulting from the proposed 20% load factor floor. When a customer's bill includes meter data resulting in a load factor less than 20%, the customer will receive a credit on their bill that is the difference between demand at a 20% load factor and the actual demand. The 20% load factor floor will reduce the amount of billed demand. Referring to the table at the bottom of page 8, the SEC2 demand attributed to House of Worship customers was reduced by 22% both inside and outside the City of Austin (COA) city limits. Based on a bill analysis, the reduction in billed demand should be 22.6% inside the COA limits and 17% outside the COA limits. The impact of this change will decrease the bills for inside city House of Worship customers, as well as other customers.

If left unchanged, the proposed rates would have collected $2,281,626 in additional revenue from S2 and $1,149,232 from S3.

Prepared by: JL
Sponsored by: Mark Dombroski

ICA 8-3 Please provide the change in S2 and S3 rates before and after the correction referenced in Dombroski rebuttal at page 9.

ANSWER:

See table:

20% LF Floor Adjustments	**S2**	**S3**
Inside		
Before	$0.02421	$0.01955
After	$0.02337	$0.01907
Outside		
Before	$0.02356	$0.01902
After	$0.02274	$0.01856

Prepared by: CTM
Sponsored by: Mark Dombroski

ICA 8-4 With respect to the adjustment for CAP revenues referenced at page 10 of Dombroski Rebuttal, provide an updated version of the class cost of service study which reflects this change. Identify the change in revenues attributed to each class. Identify the tabs, columns, dollar amounts, and line numbers for reflecting this change.

ANSWER:

Austin Energy has not updated its class cost of service study to reflect the adjustments for CAP revenue. The total CAP revenue adjustment is $7,084,569.

Prepared by: CTM
Sponsored by: Mark Dombroski

ICA 8-5 Provide an over/under recovery amount (compared to cost) for each class, before and after the change in recognizing CAP revenues.

ANSWER:

The adjustment to CAP revenue only impacts the Residential class. The difference in recovery is noted below:

Under-recovery	**Residential**
Before	$53,411,041
After	$46,326,472

Prepared by: CTM
Sponsored by: Mark Dombroski

ICA 8-6 Please provide Austin Energy's revised proposed revenue decrease (amount and percentage) by customer class, which reflects the $24.55 million reduction discussed at page 10 of Dombroski rebuttal.

ANSWER:

Austin Energy has not updated its class cost of service study to reflect the $24.55 million revenue reduction.

Prepared by: CTM
Sponsored by: Mark Dombroski

ICA 8-7 With regard to calculation of the residential over/under recovery amount provided in response to no. 8-5, above, is the CAP discount embedded in residential current revenues? Are CAP customer's revenues stated at actual amounts (i.e., at the level reduced by the discount)?

ANSWER:

Yes to both questions.

Prepared by: CTM
Sponsored by: Mark Dombroski

ICA 8-8 Mr. Dombroski (rebuttal at 10) states that the EES cost structure will be changed to "address cost causation concerns with the initial structure." Which witness or party presentation raised these concerns? Please identify the specific pages and text that raised the concerns.

ANSWER:

The testimony referenced is in response to concerns raised in Public Citizen/Sierra Club's Position Statement/Presentation on the Issues, Issue #6, pages 27-32.

Prepared by: BE
Sponsored by: Debbie Kimberly

ICA 8-9 With respect to the EES change, referenced above, please provide the increase in EES cost assignment by customer class, before and after the change.

ANSWER:

Austin Energy has not updated its class cost of service study to reflect the change in EES cost assignments by customer class.

Prepared by: CTM
Sponsored by: Mark Dombroski

ICA 8-10 Please fully discuss the method of class cost allocation of non-rebate energy efficiency costs, such as personnel, energy audit costs, training and instruction, and overhead.

ANSWER:

These costs are collected through the EES component of the Community Benefit Charge. EES costs are allocated to the classes based on the class revenue requirement.

Prepared by: JM
Sponsored by: Joe Mancinelli

ICA 8-11 Please provide the bill impact for a 1,000 and a 2,000 kWh residential customer of monthly EES charges, before and after the change referenced at page 10 of Mr. Dombroski's rebuttal.

ANSWER:

Residential Average Monthly Bill	**1,000 kWh**	**2,000 kWh**
Inside		
Before	$103.04	$235.05
After	$105.28	$239.53
Outside		
Before	$103.55	$228.25
After	$105.79	$232.74

Prepared by: CTM
Sponsored by: Mark Dombroski

ICA 8-12 Admit or deny that Austin Energy believes that energy efficiency programs reduce future utility costs paid by non-participants outside the customer class of participating customers.

ANSWER:

Austin Energy admits that energy efficiency programs reduce future utility costs of participants and non-participants. Direct participants can receive rebates or services that reduce the initial cost of the energy efficiency measure, which should decrease energy consumption and lead to a lower overall bill. On the other hand, both participants and non-participants in other classes receive an indirect benefit of reduced peak load, which may reduce the ERCOT transmission expense portion of the Regulatory Charge.

It is appropriate, however, to align program costs and benefits more closely because program participants receive direct and specific financial benefits from AE's energy efficiency programs, an important cost causation principle in utility ratemaking.

Prepared by: SJ
Sponsored by: Debbie Kimberly

ICA 8-13 Please provide the average residential customer total bill impact as a result of all of the adjustments proposed in AE's rebuttal testimony, assuming adoption of AE's recommendation. Compare it to the bill impact of AE's original proposal.

ANSWER:

See Austin Energy's Response to ICA's RFI No. 8-11 for the impact of the EES change on a 1,000 kWh/month and on a 2,000 kWh/month residential customer. Neither the change to CAP revenue nor the change to the 20% load factor floor has an impact on residential customers' bill.

Prepared by: CTM
Sponsored by: Mark Dombroski

ICA 8-14 Please provide a table comparing the relative total annual dollar impacts of AE's recommendation in this proceeding to each customer class after the adoption of AE's new rebuttal positions, and also show the percentage change in cost recovery from each customer class compared with the current revenues.

ANSWER:

	Proposed Revenues on Posted Model	Revenues after Adjustments	$ Change	% Under / (Over)-Recovered (posted model)	% Under / (Over)-Recovered (after adjustments)
Residential	451,852,198	470,200,271	18,348,073	12%	8%
Secondary Voltage < 10 kW	31,153,060	30,854,813	(298,247)	1%	2%
Secondary Voltage ≥ 10 < 300 kW	268,208,348	261,762,856	(6,445,492)	-16%	-13%
Secondary Voltage ≥ 300 kW	225,437,148	221,418,308	(4,018,840)	-7%	-5%
Primary Voltage < 3 MW	42,224,120	41,090,839	(1,133,280)	-4%	-1%
Primary Voltage ≥ 3 < 20 MW	45,929,568	44,592,917	(1,336,650)	-1%	1%
Primary Voltage ≥ 20 MW	83,744,440	81,855,075	(1,889,365)	-1%	1%
Transmission Voltage	2,144,754	2,119,321	(25,433)	-73%	-71%
Transmission Voltage ≥ 20 MW @ 85% aLF	12,547,007	12,547,007	0	4%	4%
Service Area Street Lighting	-	-	-		
City-Owned Private Outdoor Lighting	2,704,431	2,704,431	-	28%	28%
Customer-Owned Non-Metered Lighting	98,532	98,532	-	9%	9%
Customer-Owned Metered Lighting	265,958	265,958	-	31%	31%
Total	1,166,309,563	1,169,510,329	3,200,766		

Prepared by: CTM
Sponsored by: Mark Dombroski

ICA 8-15 Mancinelli rebuttal at 14 states that the Docket No. 43695 finding "presumably" pertains to interim retirements rather than ultimate retirement. What is the basis for this statement? Provide any references from Docket 43695 which he relies upon for this assertion.

ANSWER:

NewGen's industry experience was the basis for the conclusion made by witness Mancinelli. However, in reviewing additional details of Docket No. 43695, NewGen has determined:

1) The -2% net salvage value approved in PUC Docket No. 43695 for Southwestern Public Service (SPS) Steam and Other Production Plant was determined by the PUC. This percentage was recommended by the State Office of Administrative Hearings Administrative Law Judges (ALJ) and was not the result of a detailed study.[1]
2) The ALJ also concluded in PUC Docket No. 43695 that the testimony of the SPS witness was credible in that SPS does not expect to realize much value in trying to reuse or resell equipment when dismantling its fossil generating units, and found testimony from intervenors that SPS could realize "tens of millions of dollars from reusing or reselling plant equipment" to be conclusory and speculative.[2]
3) The -2% net salvage rate approved in PUC Docket No. 43695 was intended to recover dismantlement costs for all Steam and Other Production plant, and not net salvage associated with interim retirements (as was previously presumed by witness Mancinelli);
4) The Proposal for Decision in PUC Docket No. 43695 refers to PUC Docket No. 40443, involving Southwestern Electric Power Company, and indicates that the PUC approved net salvage values for production assets ranging between 0% and -22% based on plant-specific dismantlement cost studies.[3]

Based on these determinations, NewGen remains convinced that the site-specific decommissioning cost estimate developed for Decker Creek Units 1 and 2, as well as the benchmarking estimates for FPP and SHEC, were appropriately developed and yield reasonable funding requirements.

Prepared by: NH
Sponsored by: Joe Mancinelli

1 Docket No. 43695, Final Order, at FOF 111 and FOF 119. ALJ Recommendation at Docket No. 43695 Proposal for Decision pg. 129.

2 Docket No. 43695, Proposal for Decision pg. 119.

3 Docket No. 43695, Proposal for Decision pg. 127 referencing SPS Ex. 13, Watson Direct at 20, n. 9 (*citing* Docket No. 40443, Order on Rehearing, FOFs 193-194, and Docket No. 40443, Direct Testimony of David A. Davis, Exh. DAD-1 at 16-17).

ICA 8-16 Re: Mancinelli rebuttal at 19. (a) What percentage of AE's total payment for 311 is based on call volume? What percentage is based on access to the disaster recovery center?

ANSWER:

311 Call Center Test Year Costs	% of Total
Attributed to call volume	9.5%
Attributed to value as backup call center for the Customer Care contact center (*i.e.*, disaster recovery center)	90.5%
Total	100%

Prepared by: JL
Sponsored by: Mark Dombroski

ICA 8-17 Is Mr. Mancinelli aware of any electric utilities which allocate A920 on the base of gross plant, net plant, or O&M expense? If yes, please identify the electric utilities.

ANSWER:

No. Mr. Mancinelli is aware that the PUC approves allocation of FERC 920 account costs in a similar manner as that used by AE in the RFP. See Transmission Cost of Service Rate Filing Package for Non-Investor Owned Transmission Service Providers in the Electric Reliability Council of Texas (Adopted December 16, 1999).

Prepared by: JM
Sponsored by: Joe Mancinelli

ICA 8-18 Re: Mancinelli rebuttal at 20-22. What is the basis for Mr. Mancinelli's assumption that Austin Energy's administrative and executive personnel are more concerned with labor expenditures than expenditures on any other cost incurred by the utility?

ANSWER:

Administration and general's relationship to the management of the labor force is well established and recognized by the PUC as cited in Austin Energy's Response to ICA RFI No. 8-17.

Prepared by: JM
Sponsored by: Joe Mancinelli

ICA 8-19 Re: Mancinelli rebuttal at 23. Please explain whether the service initiation revenues vary in proportion to customer demands or the number of customers.

ANSWER:

Practically, these revenues may vary due to changes in customers and changes in demand. The underlying nature of the request is to connect or disconnect from the distribution system, therefore, it is reasonable to functionalize these revenues to distribution.

Prepared by: JM
Sponsored by: Joe Mancinelli

ICA 8-20 Mr. Mancinelli states at page 28 that PUC approved rate structures for TDU utilities recover distribution costs through demand and customer charges. Does he agree that the PUC's generic rate design for TDUs provides for recovery of residential and small commercial distribution costs through energy charges?

ANSWER:

TDU's recover residential and small commercial costs through energy charges because these customers do not have demand meters or have legacy rate designs that do not have demand charges. Therefore, demand related costs are recovered in energy charges because of metering or rate design constraints. However, the underlying cost driver is demand, not energy. This is true for AE, as AE recovers demand related TDU costs in the residential energy charge because of rate design considerations and not the underlying classification of costs.

Prepared by: JM
Sponsored by: Joe Mancinelli

ICA 8-21 Re: chart of FPP capacity factors on Mancinelli rebuttal page 35. Please state whether any of the capacity factor variation can be explained by forced and unforced outages. Did FPP's equivalent availability factor fluctuate over the period of this chart? If yes, what was the variation?

ANSWER:

In response to this request, AE reviewed historical data around the market, capacity factor and forced outage rates for AE's share of FPP units 1 and 2. The largest change in capacity factor occurred at the time of the nodal market transition. Additionally, the capacity factor is a function of market price and generally correlates to the South Hub market price. Forced outage rates have not changed substantially over the past few years. The forced outages that have occurred are not the main driver for the reduced capacity factor.

Prepared by: EB
Sponsored by: Joe Mancinelli

ICA 8-22 Does Mr. Mancinelli agree that the FPP annual capacity factor would be affected by expansion of wind generation during the period 2009 – 2016?

ANSWER:

FPP's annual capacity factor is related to FPP's short run variable costs and ERCOT market clearing prices. Numerous factors impact market clearing prices including wind.

Prepared by: JM
Sponsored by: Joe Mancinelli

ICA 8-23 Re: Mancinelli rebuttal at 38. Please provide the portion of the R.W. Beck report prepared for the Public Involvement Committee which discussed and made recommendations regarding production demand methodologies.

ANSWER:

Please see Attachment 1.

Prepared by: BE
Sponsored by: Mark Dombroski

Austin Energy Rate Review White Paper #3: Revenue Requirement and Cost of Service

Prepared for:
Austin Energy Rate Review
Public Involvement Committee

Released: February 23, 2011

R·W·BECK
An SAIC Company

AUSTIN ENERGY

White Paper #3: Revenue Requirement and Cost of Service

Prepared for: Austin Energy Rate Review Public Involvement Committee Meeting No. 3

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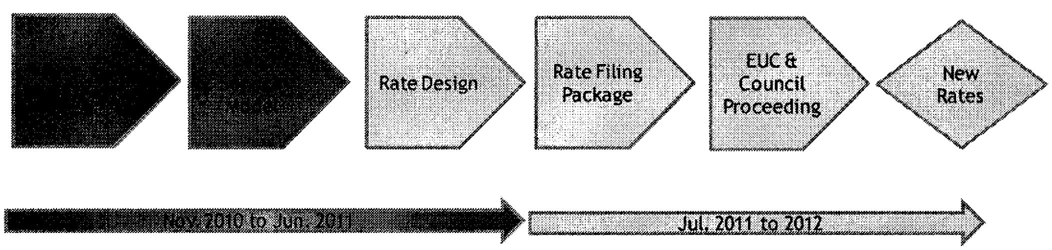
Revenue Requirement and Cost of Service

Introduction

In the first meeting of the Rate Review Public Involvement Committee (PIC), PIC members were introduced to Austin Energy's (AE) rate review process, illustrated in Figure 1. In PIC Meeting #2, the concept of customer classes was discussed and a proposed consolidation of AE customer classes based on cost differentials was presented. Appropriately designing customer classes ensures that the cost of service ("COS") analysis provides meaningful results since costs are allocated among the defined classes. PIC meeting #2 also included an overview of AE's rate design principles, which will be referred to in this paper and in future papers on rate design.

Figure 1
Austin Energy Rate Review Process



Step 1 (Determining Revenue Requirement) and Step 2 (Completing a Cost of Service Analysis) of that process are discussed in this white paper. Preliminary results of this COS analysis will be presented at PIC meeting #3 with revenue requirement shown on an overall basis and then allocated to each customer class. This document covers the following topics:

- Economic principles of COS and best practices;
- Revenue requirement methodology; and
- Unbundled COS methodology including cost functionalization, cost classification, and cost allocation.

R. W. Beck recommendations for AE's COS study are provided at the end of this paper. A note on interpreting COS results is also provided at the end of the document to serve as guidance when preliminary results are presented at PIC Meeting #3. The primary objectives of PIC meeting #3 are summarized below. This white paper and the upcoming presentation are designed to facilitate discussion on the following topics:

- Recommendations for customer class consolidation;
- Revenue requirement process and AE's preliminary revenue requirement overall and by customer class; and

- COS methodology and production cost allocation methodology to be used by AE in its COS analysis.

Rates and prices for residential and commercial and industrial customers, respectively, will be discussed at PIC Meeting #4 (April 6) and PIC Meeting #5 (May 4). PIC Meeting #6 will wrap up discussion and will discuss next steps for redesigning AE electric rates.

Economic Principles of Cost of Service

Cost of service studies are the primary analytical tool for utility ratemaking and are used to attribute costs to different customer classes based on how much it costs to serve each class. The COS study is a vital component of the overall rate review which provides an opportunity for the utility to ensure its rates follow its policies and long-term objectives (within allowable practices and principles). The policies and objectives of the utility will determine the approach the utility takes in its COS study and rate design. In turn, different approaches to cost analyses will produce different rates.

Using a COS study to determine rates is in alignment with AE Rate Design Principle 2 which states that ratemaking should be founded on economic standards common to the electric utility industry. Cost of service practices have evolved from the traditional "bundled" approach that allocates "all-in" accounting costs to customer classes, to an "unbundled" approach that allocates costs of specific products and services to customer classes. Austin Energy is using an unbundled approach in this study, discussed in detail below, to provide stronger pricing signals to customers, improve transparency, and provide greater flexibility when designing new rates.

Austin Energy Rate Design Principle 3 states that new rate design should result in fair and equitable rates, a fundamental principle of COS. An evaluation of customer classes is an important initial exercise to any rate review so that the COS analysis provides meaningful results that truly reflect differences in costs among customer types. Appropriately defined customer classes are important because the cost to serve different customer types can vary widely depending on the unique service requirement and electricity usage characteristics of the customer. Some costs to provide electric services are shared by all customers, some costs are incurred at varying levels among customer types, and some costs are unique to a specific customer or customer type. However, costs can rarely be directly assigned to specific customers. White Paper #2B described in detail how different customer types incur costs differently. PIC Meeting #2 included an analysis of load research data (data on customer classes electricity usage characteristics) to support preliminary recommendations for customer class consolidation. The COS analysis provides further insight into appropriate customer class assignment. The COS results demonstrate if actual cost differentials exist between the classes as expected.

The three main steps of a COS analysis are:

1. **Cost Functionalization.** Costs are assigned to each "function" performed by the utility, which represent the products and services provided by the utility. Many

electric utilities, like AE, have four distinct functions: 1) production, 2) transmission, 3) distribution, and 4) customer service. Cost functionalization is generally performed based on utility accounting, the aid of consultant studies, and using the experience of utility staff familiar with the utility's operations.

2. **Cost Classification**. After costs are functionalized, they are assigned to the appropriate cost components that reflect the underlying nature of the cost incurrence. Typical cost classifications are: 1) demand-related costs that vary with a customer's peak usage or demand level at specific point in time (measured in kilowatts, or "kW"); 2) energy-related costs that vary with the total amount of energy consumed by a customer (measured in kilowatt-hours or "kWh" on a monthly or annual basis); 3) customer-related costs (measured by number of customers or other appropriate measurements); and 4) direct assignments which are costs that can be easily assigned to a particular customer or customer class.
3. **Cost Allocation**. Costs are allocated to each customer class to ensure each class pays its fair share of the cost of providing electric services. Allocation factors are developed to spread classified costs to each customer class. Each allocation factor must be consistent with each type of cost classification methodology applied. For example, costs classified as energy-related are allocated to each customer class based on electricity usage.

Various methodological options for allocating costs exist for each utility function (production, transmission, distribution, and customer service). These options are based on differences in the philosophical approach to cost allocation and electricity market considerations that influence the way electricity is produced. The approach being used by AE in this study or options that AE is considering for each utility function are discussed in detail later in this document. Once the cost allocation is completed, the revenue requirement for each customer class is determined. Properly allocating costs ensures that the rates customers pay reflect the actual costs to serve them in a fair and equitable manner. Rate structures can then be considered in the rate design phase to meet strategic objectives of the utility such as encouraging energy conservation (AE Rate Design Principle 5) and needs of the community such as providing a discount to low-income customers (AE Rate Design Principle 7). Adjustments made during rate design will determine how close to actual COS customers pay for electric service.

Cost of Service Best Practices

The COS methodology is well established and has been presented to city councils, boards, regulators, and courts for decades. Best practices for completing a COS study include:

1. Founded on economic standards common to the electric utility industry (Aligns with AE Rate Design Principle 2) and established COS methodology;
2. Meet the utility's revenue requirement and represent a forward-looking utility cost structure to ensure the financial strength of the utility (Aligns with AE Rate Design Principle 4);

3. Cost tracking to allocate costs based on cost incurrence. A fair and equitable allocation of costs to customer classes based on cost causation and underlying economic principles (aligns with AE Rate Design Principles 2 and 3).
4. Produce results that are stable and can be replicated.
5. Produce results that are meaningful, practical, and understandable (Aligns with AE Rate Design Principle 8).
6. Adheres to laws and regulations (Aligns with AE Rate Design Principle 10).

Although conceptually straightforward, a COS study can be quite complex involving extensive analysis and multiple decision points throughout the study based upon an evaluation of options and policy preferences. For those that seek additional information from that provided in this document, R. W. Beck recommends the following reference manuals, courses, and resources for further study:

- Industry Reference Materials
  - Electric Utility Cost Allocation Manual (1992), National Association of Regulatory Utility Commissioners (http://www.naruc.org/store/default.cfm for purchase).
  - Retail Rate Design for Publicly Owned Electric Systems (1992), American Public Power Association (http://www.publicpower.org/Store/ProductDetail.cfm?ItemNumber=27107 for purchase).
- Industry Training Courses
  - EUCI Training Course, Introduction to Cost of Service Concepts and Techniques (www.euci.com). Course to be offered August 2011.
  - EUCI Training Course, Introduction to Rate Design for Electric Utilities (www.euci.com). Course to be offered August 2011.
- Reference Books
  - Principles of Public Utility Rates (1988, 2nd edition), James C. Bonbright (www.terry.uga.edu/exec_ed/bonbright/docs/principles_of_public_utility_rates.pdf).
  - Electric Utility Rate Economics (1972), Russell Caywood.

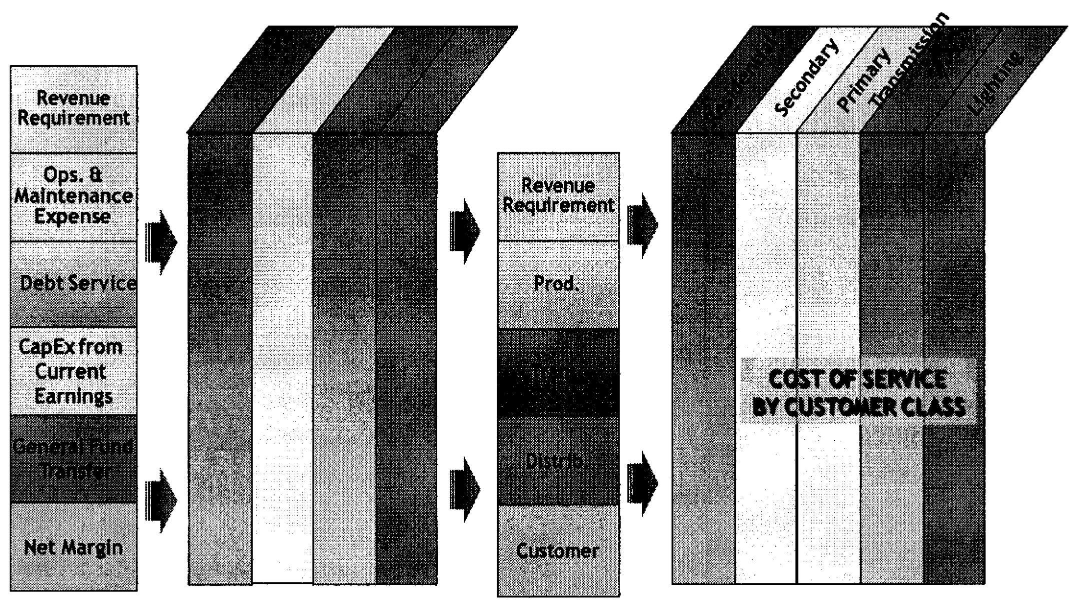
Cost of Service Methodologies

The COS methodology is well established and commonly used throughout the utility industry. Over the last decade, preferred COS methodology has evolved from a traditional approach to an unbundled approach, driven primarily by deregulation of the electric utility industry. The traditional bundled COS approach is simply concerned with allocating the utility's revenue requirement to each customer class by expense category, expressed in utility accounting terms. This process distributes the full COS study results without considering the costs associated with each utility function (production, transmission, distribution, and customer service) and how different customer classes incur costs by function. Although traditional approach COS studies are still being performed, currently the majority of studies are unbundled and R. W. Beck recommends that AE conduct an unbundled COS study as this method provides a greater understanding of the underlying cost causation than does the bundled methodology. It also provides greater flexibility of pricing service offerings.

Unbundled Approach

The unbundled COS approach considers: (1) the cost of providing specific services to customers by each utility function (production, transmission, distribution, and customer service), and (2) allocating these service-based costs to various customer classes. Unbundling translates customer service characteristics to electricity usage characteristics with associated utility investment, services, and value. Figure 2 illustrates the unbundled approach to COS with hypothetical customer classes.

Figure 2
Unbundled Cost of Service - Cash Approach



In the unbundled approach, the emphasis is on allocation of product and service costs. The traditional unbundled approach is a four-step process:

1. Determine the utility's revenue requirement.
2. Unbundle costs into the different utility functions (production, transmission, distribution, and customer service). In this approach, the entire revenue requirement is functionalized.
3. Classify the functionalized costs into demand, energy, customer, revenue, and direct assignment cost categories.
4. Allocate unbundled product and service costs to the customer classes by developing allocation factors that match cost classifications.

The unbundled approach to cost allocation mirrors utility products, services, and activities and the results are unbundled and presented from the customer's perspective. This approach allows for more flexible rate design as it allows pricing of services at different levels (meter, customer, wires, transmission and production).

Revenue Requirement

Establishing the total utility revenue requirement is the first major step in the rate review process. The term "revenue requirement" refers to the utility's total cost of serving its customers and is the basis for rate design as rates must be designed to ensure that the utility fully recovers its revenue requirement. To help ensure that rates properly recover costs into the future, the revenue requirement should represent a sustainable, forward-looking utility cost structure that aligns with the utility's strategic objectives (AE Rate Design Principle 1) and ensures the long-run financial strength of the utility (AE Rate Design Principle 4).

As stated above, COS studies are performed to determine how much it costs the utility to provide electric services to different customer types during a typical year. Thus, the utility's revenue requirement calculation includes all investments and business activities that provide value to customers within that year. While the revenue requirement should represent a sustainable, forward-looking cost structure, the revenue requirement calculation is based on historical financial records with adjustments to reflect a typical year and any new expenses that will be incurred by the time new rates are implemented. A historical fiscal year is chosen, audited, and then adjusted based on "known and measurable" criteria to reflect typical or expected future financial and operating conditions of the utility. These adjustments result in a "Test Year" which represents the total costs for the utility during a typical year. A twelve-month period is typically used to account for possible seasonal changes in energy use by customers.

Municipal utilities such as AE typically follow the "cash approach" methodology to determine their revenue requirement. Austin Energy and other municipal utilities are not for profit and are primarily concerned with paying their bills, contributing to their general fund, and meeting their financial obligations such as debt service requirements. Therefore, the revenue requirement represents the gross annual cash required to operate the utility and provide a fair return on investment. The revenue requirement calculation for a municipal utility is based on a "cash approach" and should contain the following components: (1) reasonable operating expenses; (2) debt service; (3) revenue to pay for capital projects; (4) annual deposits to replenish required reserves which are funds for anticipated future needs or contingencies; (5) general fund contribution to the city; (6) recognition of other revenues to be earned such as new service connections; and (7) generally sufficient revenues to meet all financial obligations.

Test Year Concept

As previously mentioned, a utility must select a "test year" when determining the utility's revenue requirement and completing a COS study. The test year is typically established by reviewing a historical fiscal year of the utility and this determines the financial records and load research data that will be used in the study. Austin Energy is utilizing Fiscal Year 2009 (October 2008 through September 2009) financial records for this rate review, as these are the most recent audited financial records for the utility. The standard is to begin with audited financial statements that reflect the independent review and scrutiny of an accounting firm and then adjust based on "known and measureable" criteria to reflect typical or expected future financial and operating conditions of the utility. By using this process, accurate historical records are combined with known changes to determine the appropriate test year revenue requirement for use in the COS study. By making known and measurable adjustments, the test year is effectively "trued-up" to reflect a typical operating year and include all power plants or other facilities that will be in operation at the time new rates are anticipated to be implemented. This process also helps ensure the continued financial strength of the utility (AE Rate Design Principle 4).

The Test Year 2009 revenue requirement (adjusted to include known and measurable criteria) reflects the total COS to be recovered from base rates, which must be recovered from the various customer classes in a fair and equitable manner.

Known and Measurable Adjustments

The standards and guidelines for making known and measurable adjustments vary depending on the regulatory authority reviewing the study. For COS studies reviewed by state public utility commissions, the known and measurable standard is well defined and tends to be strict. In many cases, the utility must provide sufficient proof that the adjustment truly reflects a changed operating condition and that any new facilities will be in operation by the time new rates are anticipated. Austin Energy intends to follow the standards set by the Public Utility Commission of Texas ("PUCT") in making known and measurable adjustments in this study.

Austin Energy has made several known and measurable adjustments to the audited Fiscal Year 2009 data to determine the Test Year 2009 revenue requirement. Below is an alphabetical listing of the most significant known and measurable adjustments included in AE's revenue requirement calculation.

- **Capital Improvement Program Adjustment** – As discussed previously in this paper, AE makes annual investments, or improvements, in its system through its capital improvement program. The amount of investment in new capital projects can vary by year to year. This adjustment reflects typical capital improvement program spending by taking an average of Fiscal Year 2009 actual expenditures and projections for fiscal years 2010 and 2011 assuming a 50/50 debt to current earnings capital mix.
- **Customer Class Consolidation Adjustment** – As discussed in White Paper #2B and at PIC Meeting #2, AE has proposed consolidating its current customer class

structure. Specifically, worship facilities are being removed from the residential customer class and being placed into their appropriate General Service customer classes; facilities in the city, school, and state customer classes are being removed and placed into their appropriate customer classes; current lighting customers are being consolidated into one lighting class; and new groupings of General Service and Primary Service customers based on demand on the system are being considered. The new break points for General Service customer classes are General Service < 10 kW, General Service 10 < 50 kW, and General Service ≥ 50 kW. The new break points for Primary Service customer classes are Primary Service < 3 megawatt ("MW"), Large Primary Service 3 < 20 MW, and Very Large Primary Service > 20 MW. This adjustment reflects impacts on rate revenues, including fuel revenues, from moving customers into their new customer classes.

- **Gas Combustion Turbine Adjustment** – In 2010, AE installed two new quick start natural gas-fired peaking units with a total power generation capacity of 90 MW at the Sand Hill Energy Center that will help meet summer peak demand. This adjustment includes impacts to power production costs such as fuel and operations and maintenance.
- **Labor Cost Adjustment** – Labor costs for AE have been adjusted downward to reflect AE's 2011 budget.
- **Non-Electric Expenses Adjustment** – Expenses classified as "non-electric" that AE incurred in Fiscal Year 2009 included expenses for heating and cooling systems utilizing centralized systems (e.g. chilled water systems), district energy systems, and other associated expenses. These "non-electric" expenses are generally recovered from direct billing of these systems and therefore are not recovered from electric customers in general. This adjustment removes these revenues and expenses from AE's revenue requirement.
- **Production Cost Adjustment** –The addition of new resources since Fiscal Year 2009 discussed above are or will have an impact on the operational dispatch of AE's fleet of production facilities. This has an impact on production costs including fuel costs and other operation and maintenance ("O&M") expenses. AE completed a production cost run to determine the impacts of these changes and this adjustment accounts for those projected impacts.
- **Scrubber Technology Adjustment** – Both AE and the Lower Colorado River Authority are in the process of installing pollution control equipment known as scrubber technology at the jointly-owned Fayette Power Project (coal power plant) which will reduce sulfur dioxide ("SO_2") emissions by up to 95 percent. It is expected that these scrubbers will be operational by the time new rates are implemented. This adjustment includes impacts to operations and maintenance expenses at the Fayette Power Project, including a reduction in operational efficiency of the plant which is a tradeoff of the environmental benefits of the scrubber technology.
- **Solar Power Adjustment** – In 2009, AE entered into a power purchase agreement for the purchase of energy from a 30 MW solar photovoltaic ("PV") facility located

near Webberville. This facility will be constructed during 2011 and is expected to come on-line in December 2011 prior the implementation of new rates in 2012. This adjustment is equal to the contract purchase price for energy from this facility multiplied by its estimated annual energy production, as determined by AE.

- **Weather Normalization Adjustment** – Electricity produced and sold can vary year to year depending on weather patterns and extreme weather events. It is common for a weather normalization calculation to be completed to adjust for any irregularities exhibited in the test year. System energy sales, or the amount of electricity sold by AE, in total for Fiscal Year 2009 was higher than normal due to higher than normal ambient temperatures. These high temperatures also caused the system to experience its peak demand in June of 2009, rather than the typical peak month of August. This adjustment reflects a normal weather year and a system peak occurring in August, resulting in a reduction in rate revenue, particularly fuel-related expenses. The graphs and tables in this remainder of this document are based on this normalized data.
- **Wind Power Adjustment** – Contracts for wind power expire in 2011. Wind power contracts are in the process of being renewed and new wind resources are expected to come on-line prior to the implementation of new rates in 2012. This adjustment is made to reflect the estimated costs of new wind power contracts.

Cash Approach Methodology

Austin Energy prefers the cash approach revenue requirement calculation methodology because, like most municipal utilities, its focus is on making cash payments including an annual transfer to the City of Austin's General Fund. The cash approach methodology used in this study has been developed to be consistent with AE's financial policies. An abridged listing of AE's financial policies and bond covenants is located in Appendices A and B to this document.

Austin Energy follows a form of Federal Energy Regulatory Commission ("FERC") guidelines for accounting of utility revenues, expenses, and the utility's assets. Revenues and expenses are grouped by FERC accounting numbers in AE's revenue requirement calculation and its COS study results. FERC accounting is required for all IOUs, but is not a regulatory requirement for most municipally owned utilities. However, following FERC accounting guidelines is an industry best practice that AE has chosen to follow. Key components of the cash approach revenue requirement calculation are described below.

Operation and Maintenance Expenses

Operation and maintenance expenses include all costs to operate the utility and provide electric services to customers, including customer service, and all maintenance and repair of real property incurred by the utility. Every utility must maintain and operate a system that is in a constant state of readiness with the expectation of highly reliable service. Austin Energy incurs O&M expenses for each of its four primary utility functions (Production, Transmission, Distribution, and Customer Service) so that it can maintain an efficient and reliable system and provide excellent customer service. Operation and maintenance expenses typically make up a large majority of the utility's annual expenses. For AE, O&M expenses make up greater than 70 percent of the utility's total expenses. FERC accounting methodology tracks costs within each function under the following expense categories:

- **Power Production Expenses** – O&M expenses for power production including fuel, labor, routine maintenance, system control and dispatch of power plants, and purchased power expenses. Power production is the generation of electricity.

- **Transmission Expenses** – O&M expenses for transmission lines and transmission substations including labor and routine maintenance. Electric transmission is the process by which electricity produced at power plants is transported over long distances to customers. In the Electric Reliability Council of Texas ("ERCOT"), the transmission function is defined as facilities operating at a voltage of 60,000 volts [60 kilovolt ("kV")] or higher. Costs associated with operating and maintaining AE's transmission system are recovered via a Transmission Cost of Service ("TCOS") process which is regulated by the PUCT and therefore is not included in this rate review process. These regulated transmission costs are pooled with all other transmission utilities in the ERCOT territory and distributed based on each utility's load-ratio share during the four summer peak months (June-September) using a 4 coincident peak ("4CP") methodology, a methodology explained later in this document. The load-ratio share is calculated by dividing a utility's load, or demand, on the system by the overall system load.

  In AE's current COS study this expense is reported in FERC account 565 – Transmission of Electricity by Others – to distinguish that this cost is an expense shared by all distribution utilities or load providing entities in the system and is regulated by the PUCT.

- **Distribution Expenses** – O&M expenses including labor and routine maintenance for overhead and underground distribution lines and circuitry, distribution substations, streetlights, service transformers, and meters. Electric distribution is the final stage in the delivery of electricity to customers and includes stepping down the service voltage to a level of usage that is safe for different customer types. On AE's system, distribution equipment is generally operated at 12,500 (12.5 kV) volts or less and includes the electrical equipment that directly serves customers.

- **Customer and Information Expenses** – Customer-related O&M expenses including meter reading, billing, collections, sales, advertising, customer assistance, and other customer service and communication activities.

- **General and Administrative Expenses** – Operating expenses including salaries of general and administrative personnel, office supplies and expenses, insurance, outside services, injuries and damages, employee pensions and benefits, and other general expenses.

Depreciation Expenses

Annual depreciation expenses for plant and facilities are included in AE's revenue requirement calculation, as this is required by AE financial policy. Depreciation is an annual charge included in expenses to reflect the diminishing value of an asset or group of assets over estimated useful life. As an example, an asset with an estimated life of 30 years would have one-thirtieth (1/30 or 3.33 percent) of its original cost as an annual depreciation expense to reflect the decline in value of the asset.

Depreciation expense does not represent an actual cash expense, as the cash expenditure of the asset was incurred when the asset was built or installed. Even though depreciation is a non-cash item, funding of depreciation expense creates cash for AE that is directed towards annual capital needs for improving the system and reserve requirements. The primary advantage of including depreciation in the revenue requirement calculation is that cash generated through depreciation expense mirrors existing plant-in-service, or the original cost of the current operating electric utility system. Therefore, including depreciation in the revenue requirement creates a pool of cash that is adequate to renew and replace the existing system as it naturally wears out and requires replacement to maintain system reliability.

Capital Expenditures

Most electric utilities, including AE, are extremely capital intensive because a large amount of investment is needed to develop and maintain the electric utility system. Utilities must continually add new infrastructure and renew and replace existing infrastructure to maintain high system reliability. Austin Energy funds these capital projects through its capital improvement program with a combination of debt and current earnings generated from rates. Austin Energy has an internal goal of financing about one-half (50 percent) of its capital expenditures from debt, or borrowed money, which falls within the requirements of AE's financial policies.

Debt Financing and Debt Service

The portion of AE's capital improvement program that is funded with debt is done so with a combination of short-term and long-term financing instruments. In the short term, AE utilizes a commercial paper program where funds can be borrowed as needed to pay for capital projects. The commercial paper program operates similarly to a letter of credit a homeowner may have with the bank. Typically, AE borrows short-term through the commercial paper program and builds a balance over a 12 to 18-month period. Typically, over this time AE will have borrowed approximately $150 million in support of funding approximately one-half of its capital program. When short-term borrowing reaches this level, AE converts the commercial paper into long-term debt, typically in the form of electric utility revenue bonds. Long-term debt is similar to a homeowner's mortgage and requires AE to pay principal and interest on the debt over the term of the issue. The term of AE's long-term debt is generally 30 years as per financial policy AE cannot finance capital projects beyond their useful life.

AE's revenue requirement calculation includes annual debt service expense (principal and interest) associated with long-term debt plus interest expense related to short-term commercial paper borrowing. Per financial policy, AE must maintain a debt service coverage ratio of 2.0 times on electric utility revenue bonds. The debt service coverage ratio is the ratio of cash available for debt servicing to interest, principal, and lease payments. AE's revenue requirement must ensure that this policy is met.

Capital Paid from Current Earnings

The remainder of the capital improvement program is paid with cash made available through rate revenues. Austin Energy maintains this cash in its Capital Improvement Program Fund and its Repair and Replacement Fund. In AE's revenue requirement calculation, capital improvement projects funded with cash are included in the Net Margin calculation described below.

General Fund Transfer

It is common practice for municipally owned electric utilities like AE to transfer a certain percentage of revenues to the city, similar to the way an IOU provides a dividend to its shareholders. Reinvesting back into the community rather than paying out to investors is a unique benefit of public power. Austin Energy provides its General Fund Transfer to the City on an annual basis in the amount of 9.1 percent of adjusted gross utility revenues averaged for the current budget year and the two most recent historical operating years. This transfer helps pay for community services including public safety, parks, and libraries and keeps other fees and taxes low. The General Fund Transfer is included in AE's revenue requirement calculation.

Net Margin

Austin Energy's revenue requirement calculation also includes a margin calculation. This margin calculation reflects the remaining cash needs of AE after all other components of the revenue requirement have been considered. The margin calculation takes into consideration sources of cash from depreciation and interest income less cash needs required to support the capital improvement plan and other contributions as needed.

Revenue Requirement Offsets

As described above, all of the components of the revenue requirement calculation capture the total COS for the utility. Since the objective in assessing overall revenue requirement is to determine the total costs to serve customers and recover these costs from rates, utility revenues that lower the amount needed to be covered through rates must be calculated as an offset. Several sources of funds are used to meet the utility's revenue requirement, some of which offset the overall revenue requirement to be met by rate revenues. Funds for meeting a utility's total revenue needs include: 1) base rates, 2) other income adjustments, and 3) pass-throughs.

Other Income Adjustments

Other sources of income that are not related to rate revenues must be netted against the total system revenue requirement. Other sources of income include fees and charges related to connection fees, equipment rentals, service charges, and maintenance agreements, among others. These income adjustments lower the overall revenue requirement.

Pass-throughs

In addition to other income adjustments, pass-throughs, or rate adjustment riders, must be in the revenue requirement calculation to distinguish between costs directly passed through to customers and base rates. Pass-throughs are adjustments to base rates that can be made outside of a full rate review to reflect changes in actual costs from year to year. An example of a common pass-through cost is a fuel charge that is typically billed to customers based on total monthly amount of electricity consumed. Fuel costs are commonly reflected in a fuel adjustment clause due to the volatility of fuel prices and uncontrollable nature of fuel markets.

Austin Energy, with the assistance of R. W. Beck, is currently evaluating the functionality and appropriateness of these and other potential rate adjustment riders in the rate review. The benefit of rate adjustment riders is improved transparency of the impact of those costs on customer electric bills and the flexibility to adjust the riders without completing a full COS study. Austin Energy currently has two rate adjustment riders:

- **Fuel Adjustment Clause Rider** – This rider directly passes the estimated costs of fuels and related expenses, including refunds and the cost of purchased power to customers based on total electricity consumed in a month. Austin Energy keeps track of fuel costs in a balancing account and periodically adjusts the rider so that the balancing account retains a value as near to zero as possible. For example, in January 2011 AE reduced its fuel charge by 15 percent to reflect lower fuel prices. For more details on the fuel charge and the calculation go to:

  http://www.austinenergy.com/About%20Us/Rates/fuelAdjustmentClause.htm

- **Transmission Service Adjustment Rider** – This rider was implemented in fiscal year 2011 (October 2010) to account for increased state-wide transmission expenses related to the on-going Texas electric transmission grid build-out to help bring energy, including renewable energy, from West Texas to population centers in Texas like the Austin metropolitan area. This rider passes through costs that are calculated based on the TCOS process described above which is regulated by the PUCT. For more details on the transmission service adjustment rider and the calculation go to:

  http://www.austinenergy.com/about%20us/rates/Commercial/transmissionServiceAdjustmentRider.htm

Base Rates

Once AE's overall revenue requirement is adjusted for other income and pass-throughs, the remaining balance must be recovered through base rates. Base rates are a common industry term that describes customer charges, demand charges, and energy charges that do not tend to vary between rate reviews as these charges are typically only adjusted after completing a full COS study.

Table 1 is a template for presenting AE's revenue requirement and includes the above-described elements of AE's revenue requirement calculation. Preliminary values will be provided at PIC Meeting #3 on March 2. This template is provided to familiarize PIC members with the way in which these preliminary results will be presented at the meeting.

Table 1
Results Template: Austin Energy Overall Revenue Requirement

Austin Energy
Test Year Revenue Requirement Template
Cash Approach

Item	Test Year 2009
Operation and Maintenance Expense	
Production	
Transmission	
Distribution	
Customer and Information	
Administration & General	
Subtotal Operation and Maintenance Expense	V
Depreciation Expense	
Debt Service	
General Fund Transfer	
Net Margin (from below)	
Subtotal Revenue Requirement	W
Less Other Adjustments:	
Other Income	X
Pass Throughs	Y
Subtotal Other Adjustments	X+Y
Net Revenue Requirement for Base Rates	RR = (V+W+X+Y)
Base Rates	BR
Difference	RR - BR
Margin Calculation	
Sources of Funds	
Depreciation	
Interest Income	
Total Sources of Funds	A
Uses of Funds	
Capital Paid from Current Earnings	
Total Uses of Funds	B
Net Margin	A – B

Austin Energy's Unbundled Cost of Service

Cost of service studies used to attribute costs to different customer classes based on how much it costs to serve each class. The following section describes the steps in the cost of service process once the revenue requirement is determined. These steps allow the utility to determine the revenue requirement by customer class, which represents their cost of service.

Cost Functionalization

Once the utility's revenue requirement has been determined, how much each customer class should pay is determined by a COS study. The second step in an unbundled COS study consists of functionalizing the revenue requirement into the various utility functions (production, transmission, distribution, and customer service).

In theory, each utility function faces unique market environments, business risks, and objectives. Therefore, cost drivers and pricing is unique to each function. Table 2 summarizes the unique characteristics of each of AE's functions:

Table 2
Major Utility Functions of Austin Energy

Function	Market Environment	Business Risk	Key Drivers
Production	Competitive	High	Availability and Low Cost
Transmission	Regulated by PUCT	Low	System Reliability and Open Access
Distribution	Locally Regulated by City of Austin	Low	System Reliability
Customer Service	Locally Regulated by the City of Austin	Low	Customer Satisfaction and Responsiveness

Each AE business function offers a variety of products and services to the market. The products and services can be bundled and priced in the traditional manner or unbundled and priced separately.

Assigning Costs to Functions

Costs are then assigned to each function and its respective products and services. The assignments fall into two general categories: 1) direct assignments and 2) derived allocators.

Direct Assignments

Costs that are readily identifiable to a specific utility function can be directly assigned to that function. In Table 3, accounting category FERC Account 585 Street Lighting Expense is directly related to the distribution function only. Therefore, 100 percent of the costs of street lighting ($47,844) are assigned directly to the distribution function. In fact, FERC Account 585 Street Lighting Expense can also be directly assigned to the Street Lighting Class in the cost allocation phase.

Table 3
Direct Assignment Example: Street Lighting Expense

FERC Acct.	Description	Alloc. Method	Amount	Prod.	Trans.	Dist.	Cust.
585	Street Lighting	Direct	$47,844	$0	$0	$47,844	$0
	Allocation %		100%	0%	0%	100%	0%

Derived Allocations

Derived allocations are allocation factors that are based on the sum, average, or weighted effect of different underlying factors. Derived allocators can be complex and should reflect the logical answer to the follow question "what underlying activities drive the cost of this cost item?" For example, general and administration expenses are associated with the management and operation of all utility functions and thus are incurred throughout the utility in each function. Many general and administration activities are associated with the management of utility staff. Therefore, these expenses are typically allocated to each function based on labor cost, which can be measured by the "level of effort" by function. Measures of the level of effort of managing the labor force include "employee salaries" and "number of employees." In this case, we chose to use employee salaries. Table 4 shows total utility labor salaries charged by function. Based on AE's accounting methodology, a portion of the salaries are directly assigned to the production function.

Table 4
Derived Allocation Example: Labor Costs

Function	Total	Prod.	Trans.	Dist.	Cust.
Production	$10,470,000	$10,470,000	$0	$0	$0
Transmission	4,080,000	0	4,080,000	0	0
Distribution	12,540,000	0	0	12,540,000	0
Customer	15,850,000	0	0	0	15,850,000
Direct	1,910,000	1,910,000	0	0	0
Total	**$44,850,000**	**$12,380,000**	**$4,080,000**	**$12,540,000**	**$15,850,000**
% Allocation	100%	28%	9%	28%	35%

In Table 5, total employee salaries for each function, derived in Table 4, are used to allocate FERC Account 920 Administration and General Salaries to each function. For example, 28 percent of total salaries are assigned to the production function so this becomes the allocation factor for administration and general salaries.

Table 5
Allocation Example: Administration and General Salaries

FERC Acct.	Description	Alloc. Method	Amount	Prod.	Trans.	Dist.	Cust.
920	A&G Salaries	Derived	$44,850,000	$12,380,000	$4,080,000	$12,540,000	$15,850,000
	Allocation %		100%	28%	9%	28%	35%

Cost Classification

Once the functionalization step is completed, the next step in a COS study is to classify costs. Cost classification seeks to identify costs by their underlying nature meaning what drives cost such as electricity consumption, peak demand, and customer service needs. Typical cost classifications include demand-related costs that vary with customer peak usage or demand level (measured in kW),energy-related costs that vary with the amount of energy consumed by a customer (measured in kWh), customer-related costs (measured in number of customers), revenue-related costs (measured by revenue), and direct assignment costs.

Demand-Related Costs

Demand-related costs are driven by the overall demand on the system (measured in kW). The utility must maintain a system of wires and production facilities that can meet the highest point of demand on the system and at any point in the system. Thus, the overall system demand and each customer's contribution to that is a major cost driver for the utility's capital costs. Demand-related costs are associated with production, transmission, and distribution functions. For example, the gas combustion turbine generators owned and operated by AE are only needed when demand is at its highest and thus provide an example of a likely demand-related cost because the cost driver is the need to rapidly respond to fluctuations in system peak demand.

Energy-Related Costs

Energy-related costs are expenses that vary with total monthly energy consumption (measured in kWh). The most significant energy-related costs incurred by the utility incurs is fuel costs which are directly related to the amount of electricity consumed by customers. The amount of coal, natural gas, and nuclear fuel expenses incurred by AE are energy-related costs. Variable production costs such as water and chemicals are also classified as energy-related costs.

Customer-Related Costs

Customer-related costs are expenses that are driven by the number of customers served and the unique customer service needs of different customer classes. For example, billing and meter reading are customer-related costs.

Direct Assignments

Direct assignments in the cost classifications step are costs easily identifiable to a particular customer or customer class. For example, street light expenses are typically directly allocated to the lighting customer class.

Table 1 was provided earlier in this paper as a template for presenting AE's revenue requirement based on expense category and various financial accounting considerations that must be taken into account. Table 6 is a complementary template for interpreting the revenue requirement results with results broken down by utility function. In this table one can see how each utility function contributes to the overall revenue requirement. The total revenue requirement value should be the same in both Table 1 and Table 6. Again, this template is provided to familiarize PIC members with the way in which these preliminary results will be presented at the next PIC meeting.

Table 6
Results: Template Austin Energy Revenue Requirement Results By Function

Austin Energy Test Year Revenue Requirement by Utility Function	
Item	**Test Year 2009**
Production	
Demand Related	
Base Load	
Intermediate	
Peaking	
Power Purchases	
Renewable	
Subtotal Demand Related	
Energy Related	
Base Load	
Intermediate	
Peaking	
Power Purchases	
Renewable	
Subtotal Energy Related	
Total Production	
Transmission	
Demand Related	
High Voltage - 138/345 kV	
Sub Trans – 69 kV	
Load Dispatch	
Transmission - By Others	
Subtotal Demand Related	
Total Transmission	
Distribution	
Demand Related	
Primary - Subs, P&C	
Secondary - P&C	
Transformers	
Load Dispatch	
Subtotal Demand Related	
Customer Related	
Meters	
Services	
Meters	
Subtotal Customer Related	
Direct Assignment	
Lighting	
Subtotal Direct Assignment	
Total Distribution	
Customer	
Customer Related	
Customer - Accounting	
Customer - Service	
Uncollectibles	
Key - Accounts	
Subtotal Customer Related	
Total Customer	
Total Test Year Revenue Requirement	

Cost Allocation

Cost allocation is the final step of the COS study and is performed to ensure that each customer class pays its fair share of the cost of providing electric services. In this step, allocation factors are developed and applied to appropriately distribute classified costs to each customer class. Each allocation factor must be consistent with each type of cost classification methodology applied. For example, costs classified as energy-related are allocated to each customer class based on the electricity usage of that customer class. Customer information and load research is used to determine how to spread costs among customer classes.

Once cost allocation is completed, the revenue requirement for each customer class can be determined. For AE's COS study, costs are allocated to the following proposed new AE customer classes:

- Residential
- General Service Secondary - < 10 kW
- General Service Secondary - ≥ 10 kW – < 50 kW
- General Service Secondary - ≥ 50 kW
- Primary Service - ≤ 3 MW
- Primary Service - > 3 MW – < 20 MW
- Primary Service - ≥ 20 MW
- Transmission
- Lighting

Based on additional analysis it was determined that one additional customer class from those presented at PIC Meeting #2, Primary Service ≥ 20 MW, should be added due to the unique service requirements and electricity usage characteristics of these particularly high usage industrial customers. The remainder of this section describes the use of different types of allocation factors to spread the classified costs across these customer classes. The focus of this section will be on demand allocation factors, specifically the allocation of production demand, as this tends to be the most significant cost incurred by the utility and the most controversial during cost allocation.

Demand Cost Allocation Methods

Demand-related costs are expenses that are driven by the overall demand on the system (measured in kW). Costs classified as demand-related are associated with the production, transmission, and distribution functions. Within each function, the allocation of demand-related costs to each customer class is based on accepted industry practices that seek to fairly assign costs based on the way costs are incurred by the utility. Demand allocation methods can vary by utility due to differences in the utility's business and cost structure, customer base, customer characteristics, and rate design philosophy.

This paper only describes demand allocation methods that R. W. Beck considers pertinent to AE given its unique operating environment and customer base. For those who are interested in descriptions of all demand allocation techniques, an excellent resource is the "Electric Utility Cost Allocation Manual" published by the National Association of Regulatory Utility Commissioners ("NARUC").

Production Demand Cost Allocation Methods

As stated above, of the three major utility functions - production, transmission, and distribution - the methodologies for allocation of transmission and distribution demand costs are straightforward and generally accepted across the industry. The methodologies for production demand tend to be the most complex.

NARUC's Electricity Cost Allocation Manual classifies production demand allocation methodologies into the following three categories:

1. **Peak Demand Methods** – Allocates production costs to customer classes based on the class contribution to the system peak anywhere from 1 to 12 months of the year (known as 1CP, 2CP, etc.). These methods recognize that a utility is primarily concerned with having enough production capacity to meet the system peak and that this is the utility's primary cost driver for capital investment.
2. **Energy Weighting Methods** – Allocates production costs to customer classes based on a combination of demand and energy measures. These methods recognize that a typical portfolio of power generation resources, or production assets, is designed to serve both the peak demand and energy needs of the system and each customer it serves. A utility's power generation portfolio is classified as a certain percentage of demand and certain percentage of energy and these costs are allocated to each customer class based on an evaluation of the utility's power generation portfolio and customer electricity usage characteristics.
3. **Time Differentiated Methods** – Allocates production costs to customer classes based on how the underlying power generation resources are used. These methods evaluate each individual resource to determine its COS and then allocate the resource to each customer class based on electricity usage.

These approaches give rise to four methodologies that R.W. Beck considered as the basis for AE's COS study.

1. Coincident Peak - Peak Demand Method
2. Average and Excess Demand ("AED") – Energy Weighting Method
3. Probability of Dispatch ("POD") Method – Time-Differentiated Method
4. Baseload, Intermediate and Peaking ("BIP") Method - Time-Differentiated Method

These production demand cost allocation methodologies are used throughout the industry. Each of these approaches is used in the electric utility industry for different reasons. The rationale for each of these approaches and the appropriateness of each method for AE is provided below. This paper includes an initial recommendation from R. W. Beck for the approach that AE should use considering the current electricity market in which it operates. These approaches will be discussed further at PIC Meeting #3 and PIC members will have the opportunity to provide input on which method AE should use in its COS study.

Coincident Peak Method (Peak Demand Method)

Peak Demand Methods are the the most simple in application as demand-related costs are allocated to each customer class simply based on each class' contribution to the system peak, known as coincident peak ("CP"). For this reason, these methods are known as coincident peak methods. Coincident Peak methods can vary from a single coincident peak ("1CP") to the average of the coincident peaks of each month up to 12 months of the year ("12CP"). The selection of the appropriate number of months to evaluate depends upon the unique circumstances and philosophy of the utility.

The advantage of the 1CP method is that it recognizes that a utility's capital investment costs are driven by power generation capacity needs at the system peak. The disadvantage of this method is that the resulting allocation of costs to each customer class can be highly variable, meaning that various factors could skew these results. The system peak can be influenced by a number of factors including weather and special events that may disproportionately affect the amount of electricity consumed by certain customer types at the time of system peak. Therefore, the time of the system peak may change from year to year and each customer class' contribution to that peak may change significantly as well. The variance of coincident peak demand among classes each year is not ideal from a COS perspective as a COS study should reflect a consistent, forward-looking utility cost structure assuming no measurable changes in the underlying customer electricity usage characteristics.

To address variability exhibited by the 1CP method, it is common practice to consider the system peak over several months and allocate demand–related costs based on the average of the number of monthly peaks considered during the test year. For example, if demand-related costs were allocated based on the class contribution to the system peak during the six months with the highest system peak, the method used is called the 6CP method. Generally, the more months considered, the less variability there is with the results.

Figure 3 shows the monthly system peaks for AE during Fiscal Year 2009, the test year for this COS study.

Figure 3
Austin Energy Monthly System Peaks (Fiscal Year 2009)

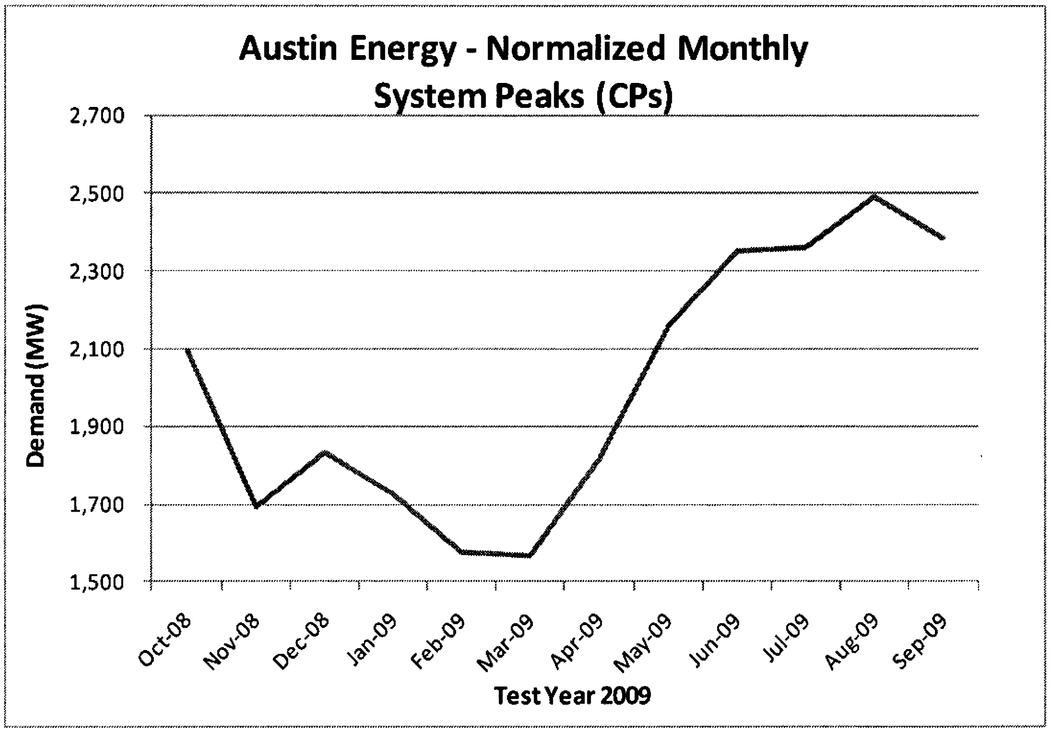


Figure 3 shows that AE experiences a significant summer peak from June through September. The primary cause of this peak is increased air conditioning load during the hottest summer months. Austin Energy's system is designed to have sufficient power generation capacity to meet demand during this summer peak period. As such, R. W. Beck recommends allocating demand-related costs to each customer class based on the four summer peak months or the 4CP method. Under this approach, the average of each customer class' contribution to the system peak, or coincident peak, for each of these four summer months is used to determine the cost allocation of demand-related costs. Table 7 shows the results of the 4CP allocator for three of AE's eight customer classes as an illustration of this method and includes the percentage of contribution to total costs among these three classes.

Table 7
Allocation Factors Derived from the 4CP Demand Method

Customer Class	4CP	Percent of Total
Residential	3,788,459	50%
General Service ≥ 50 kW	3,398,317	44%
Primary ≥ 20 MW	479,657	6%
Total	**7,666,432**	**100%**

Average and Excess Demand Method (Energy Weighting Method)

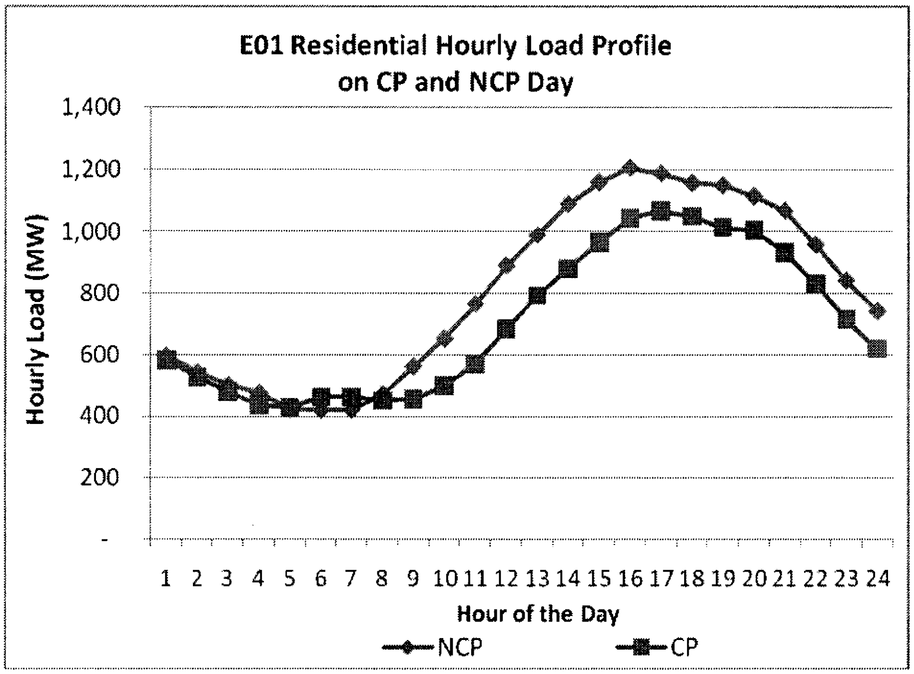
The most widely used energy weighting method is the AED method. The AED method recognizes that the utility's power generation resource portfolio is designed to meet both demand and energy needs of its customers and that customers benefit from this design. Under this method, the electricity usage characteristics of each customer class are evaluated to determine class "average demand" and class "excess demand." Average demand (measured in kW) is a measure of the demand a class places on the system over the course of the year. Average demand is calculated by dividing annual customer class electricity usage (measured in kWh) by the typical number of hours in a year (8,760). Average demand by customer class for AE is shown in Table 8. Table 8 presents example data for annual energy use and average demand for three of AE's customer classes and includes the percentage of contribution to total energy and demand among these three classes.

Table 8
Austin Energy Average Demand By Customer Class

Customer Class	Annual Energy (kWh)	Percent of Total	Average Demand (kW)	Percent of Total
Residential	4,104,103,537	39%	464,721	39%
General Service ≥ 50 kW	4,530,098,043	43%	518,663	43%
Primary ≥ 20 MW	1,853,822,395	18%	113,803	18%

Excess demand measures the difference between the customer class' annual maximum demand and its annual average demand. As discussed previously, maximum demand is the measure of highest demand, or peak demand, for a particular customer or group of customers. This peak can happen at any time of the year and may or may not be coincident with the system peak. For this reason, this measure is referred to as the non-coincident peak ("NCP") of the customer class. Figure 4 shows an hourly load profile for the AE Residential customer class, represented as the NCP, compared to the system peak, represented as the CP.

Figure 4
Austin Energy Residential Hourly Load Profile



Consistent with the results shown in Figure 4, a customer class' NCP is usually higher than the class CP unless the timing of the class peak is exactly the same as the timing of the system peak. The Residential customer class peak occurs one hour before (hour 16 or 5 pm) the system peak (hour 17 or 6 pm).

To calculate excess demand, one takes the customer class' NCP and subtracts average demand. Table 9 shows the NCP, average demand, and excess demand for three of AE's customer classes and includes the percentage of contribution to total demand among these three classes. For each of the customer classes shown, the percent of contribution to total excess demand is shown in the far right column.

Table 9
Austin Energy Excess Demand By Customer Class

Customer Class	NCP	Average Demand	Excess Demand	Percent of Total
Residential	1,194,102	464,721	729,380	63%
General Service ≥ 50 kW	939,548	518,663	420,886	36%
Primary ≥ 20 MW	126,289	113,803	12,486	1%
Total	**2,259,939**	**1,097,188**	**1,162,751**	**100%**

After excess demand is calculated by customer class, each class' excess demand is adjusted to match system excess demand. System excess demand is calculated by comparing the system peak (1CP) with the system average demand. Class excess demand is trued up to equal system excess demand so that the system excess demand can be attributed to each class. Once this adjustment is completed average demand and excess demand is summed for each customer class. This summation results in the AED allocator for each class and reflects the relative mix of energy and demand as a cost driver for each class. Table 10 shows the results of the AED allocator for three of AE's customer classes and includes the percentage of contribution to total costs based only on these three classes.

Table 10
Allocation Factors Derived from the Average and Excess Demand Method

Customer Class	AED	Percent of Total
Residential	1,025,299	52%
General Service ≥ 50 kW	842,142	42%
Primary ≥ 20 MW	123,399	6%
Total	**1,990,840**	**100%**

Probability of Dispatch (Time Differentiated Method)

Time differentiated allocation methods, such as the POD method, tend to be the most complex in terms of analysis as this requires aligning hourly system load, or demand, requirements with hourly dispatch of resources. Under this approach, each customer class is allocated production costs in proportion to their respective use of each power generation resource serving the customer. Therefore, depending upon how resources are dispatched, production costs can be classified as both demand-related and energy-related. There are two major time differentiated methods used today: the POD method and the BIP method. In 1997 the Austin City Council adopted a policy endorsing the POD method for future COS studies. The POD method requires the utility to develop an actual or estimated annual hourly load curve for the system as a whole and for each customer class. The hourly load curve shows demand at each hour of the day, month, or year. The utility then analyzes dispatch of power production resources to meet system load to determine how the costs of operating each resource should be allocated to each customer class based upon the timing of dispatch of resources in relation to the level at which each customer class is consuming electricity during those times. Under this method, each customer class is responsible for the cost of operating each production resource for every hour of the year rather than just during the peak hours. While this method more accurately reflects the actual costs to serve customers, it is only valid if the system load and production resources are directly linked every hour of the year. At the time the POD method policy adopted by the City of Austin, this assumption was generally valid as AE was obligated to meet its load through its power generation resource portfolio. Austin Energy would dispatch its power generation resources to meet its system load, or demand, requirements. As long as the wholesale power market consisted of bundled, fully integrated electric utilities, the POD method provided a well-reasoned and highly accurate means by which to allocate production costs. However, AE no longer operates in this type of a market beginning with deregulation of the electricity market in competitive portions of ERCOT and more recent changes in market structure. Deregulation of the Texas electric market forced electric utilities in the competitive markets to unbundle their operations and compete for retail load. Beginning in 2002, ERCOT began dispatching generation resources statewide to meet statewide load requirements, meaning that AE's power generation resources were grouped in an ERCOT-wide dispatching process. In December 2010, ERCOT converted from a zonal market to a nodal market, a Location-based Marginal Pricing ("LMP") market. In the nodal market, all power generating units in ERCOT are dispatched to meet the entire ERCOT system load. Whereas in the zonal market each generation owner scheduled its own resource outputs, the nodal market transition moved to a centralized economic dispatch model run by ERCOT in which supply costs are calculated at the marginal costs to supply power through over 5,000 pricing points, or nodes. Thus, AE must bid its resources into the market against other generating units across ERCOT and units are dispatched to serve the greater system load at least cost, considering reliability needs. This ERCOT-wide economic dispatch is expected to improve the efficiency of the system and lower costs to the system, utilities, and ultimately customers. As a result, AE's power generation resource, or production, fleet is no longer directly tied to fluctuations in AE's hourly load. Rather, AE's production fleet is tied to fluctuations in the entire ERCOT load.

This fundamental change in the market structure alters how resources are dispatched and greatly diminishes the usefulness of the POD method for AE in this rate review. Because the nodal market relies upon cost considerations on a detailed node by node level, it becomes virtually impossible to link specific supply costs for AE with AE customer class loads. Hence, the POD method no longer accurately reflects the manner in which AE plans or operates its power generation resources and therefore there is no basis for using this method in this rate review.

Given the City's policy to use the POD method, but considering the broader context of the current ERCOT market and limitations to the POD method imposed by recent market changes, R. W. Beck recommends using an alternative method that preserves the fundamental linkage between power generating resource dispatch and load requirements. This alternative methodological approach is a time-differentiated method similar to the POD method referred to as the Baseload, Intermediate, and Peak Method.

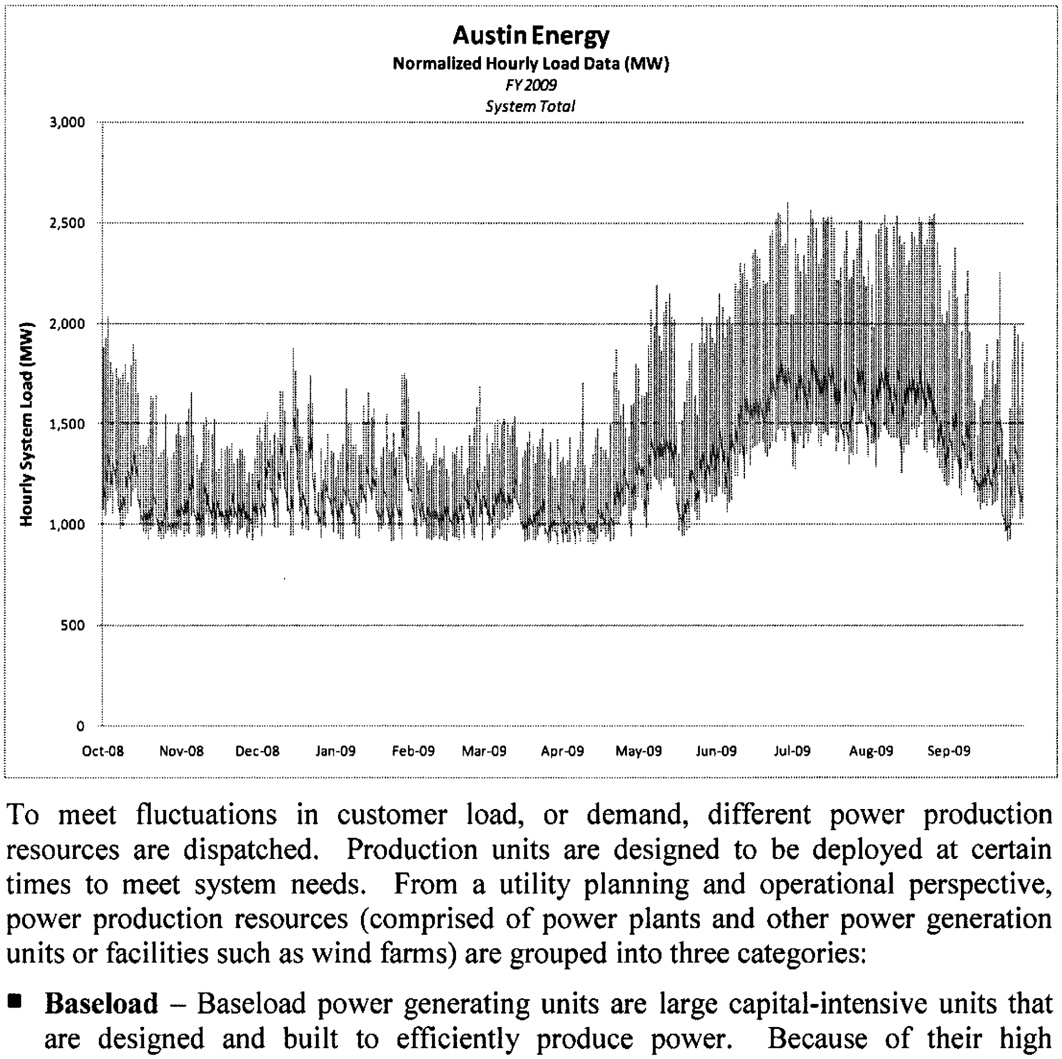
The Baseload, Intermediate, and Peak Method (Time Differentiated Method)

The BIP allocation method allocates demand-related production costs to customer classes based on each customer class' contribution to system load during assigned baseload, intermediate, and peak time periods. This method more accurately reflects the way in which the utility incurs costs for producing electricity and how customer class characteristics including energy demand and overall energy use drive those costs. The need for this type of method is best illustrated by showing the variability in load, or demand, experienced by a utility such as AE. Figure 5 shows hourly load, normalized for weather, for Fiscal Year 2009, AE's test year for this study. Notice the extreme amount of variation by day and season over the course of a year. Load fluctuates from just under 1,000 MW to slightly over 2,500 MW (an over 150 percent difference). Despite load often being relatively low, AE must design a system that can handle the peak load. This means that much of the system is in use for only a portion of the time during the year, creating natural economic inefficiencies. Table 11 shows the results of the BIP allocator for several AE customer classes and includes the percentage of contribution to total costs based on these three classes.

Table 11
Allocation Factors Derived from the BIP Demand Method

Customer Class		Allocator	BIP kW	Percent of Total
Residential	Baseload	Avg Demand	464,721	
	Intermediate	12 CP	8,682,271	
	Peaking	4 CP	3,788,459	47%
		Sub-Total	12,935,451	
General Service ≥ 50 kW	Baseload	Avg Demand	518,663	
	Intermediate	12 CP	8,724,454	
	Peaking	4 CP	3,398,317	46%
		Sub-Total	12,641,434	
Primary ≥ 20 MW	Baseload	Avg Demand	113,803	
	Intermediate	12 CP	1,401,406	
	Peaking	4 CP	479,657	7%
		Sub-Total	1,994,866	
Total			**27,571,751**	**100%**

Figure 5
Austin Energy Normalized Hourly Load (Fiscal Year 2009)



To meet fluctuations in customer load, or demand, different power production resources are dispatched. Production units are designed to be deployed at certain times to meet system needs. From a utility planning and operational perspective, power production resources (comprised of power plants and other power generation units or facilities such as wind farms) are grouped into three categories:

- **Baseload** – Baseload power generating units are large capital-intensive units that are designed and built to efficiently produce power. Because of their high efficiency and limitations for ramping up and down, these units run most of the time (typically 80 percent or more of all hours during the course of a year), with the exception of during repairs or scheduled maintenance. These units tend to have high fixed costs and relatively low variable (predominantly fuel) costs. Coal power plants and nuclear power plants are the most common baseload plants. Austin Energy is co-owner of two units at the Fayette Power Project coal plant, with a total share of 607 MW of power generation capacity. Austin Energy is also part owner of the South Texas Project nuclear plant with a share of 422 MW of power generation capacity. These two facilities meet AE's baseload power needs.
- **Intermediate** – Intermediate power production units are designed to be flexible and efficient and meet demand during the times between baseload and system peak when demand varies substantially. These resources follow system load on a daily and seasonal basis and fall between baseload and peaking plants in terms of usage

and efficiency. Intermediate resources can be easily ramped up or down depending upon the need. Intermediate units generally have lower fixed costs than baseload units but higher variable costs and typically run 40 to 60 percent of the time. Austin Energy's intermediate power generating units are the natural gas-fired steam turbines at the Decker Creek Power Station (741 MW capacity) and the natural gas-fired combined cycle units at the Sand Hill Energy Center (312 MW capacity).

- **Peaking** – Peaking production units are designed to meet the system peak and must have the capability to start quickly to meet system needs over short periods of time when system demand is the highest. These units typically have the lowest fixed costs but the highest variable costs. Typically, peaking units operate less than 20 percent of the time. Austin Energy's peaking power generating units are the natural gas-fired combustion turbines at Decker Creek Power Station (193 MW capacity) and the Sand Hill Energy Center (287 MW capacity).

Wind and solar resources are unique in that their availability depends on whether the wind is blowing or the sun is shining. These technologies can only generate electricity during certain periods of the day due to the variable nature of the energy source. As such, renewable resources cannot be dispatched or controlled to meet fluctuating demand. For this reason, these resources do not fall under one of the categories above, although wind and solar resources are sometimes classified as baseload resources in utility planning studies since the resource is used at all times available assuming no other constraints on the system.

Figure 6 organizes and sorts AE's system hourly load fluctuations to represent how often these categories of resources are used over the course of a year. Figure 6 includes AE's load duration curve which represents the total load, or demand, on the system for each hour during a typical year. The load duration curve is not a chronological hourly representation (as shown in Figure 5 above), but rather provides the number of hours for each amount of load cumulated over the course of the year. Figure 6 also depicts the specific resources by type required to meet system demands over the course of the year. Resources are grouped as baseload, intermediate, and peaking units. Austin Energy resources that fall under these categories are listed above. Wind resources are grouped into the baseload category.

Figure 6
Austin Energy Load Duration Curve and Resource Stack

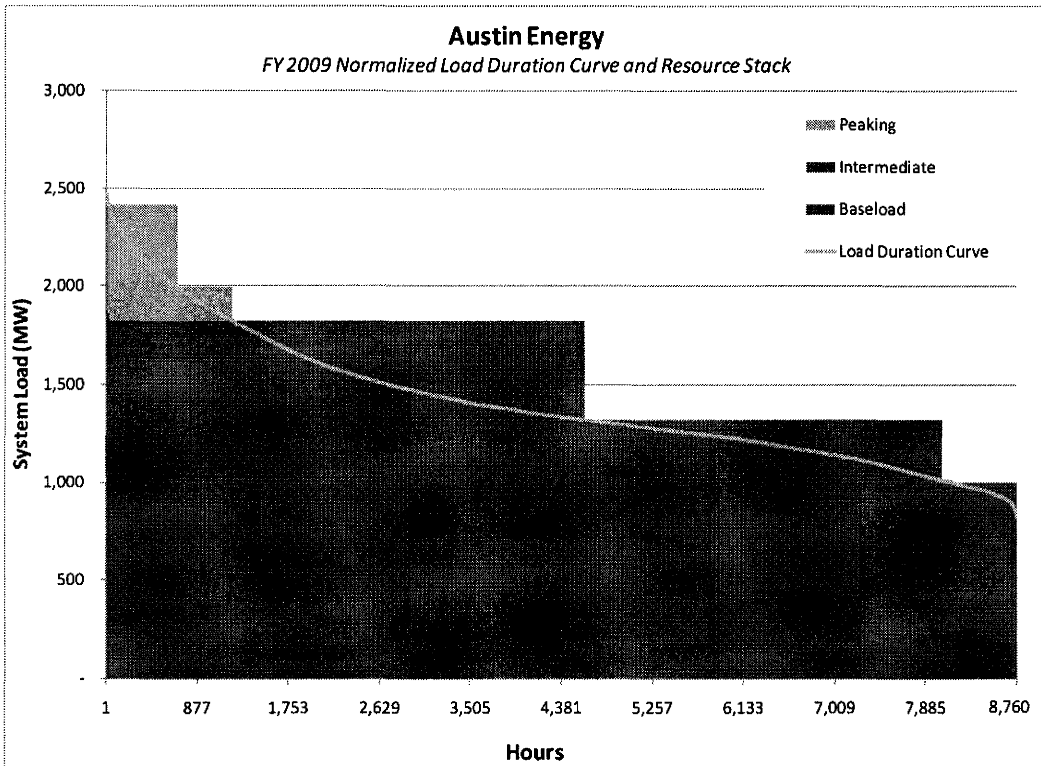


Figure 6 shows that the peak hour on AE's system in 2009 was approximately 2,500 MW of load. It also shows that system load was never lower than approximately 750 MW over the course of 2009 and is above 970 MW over 98 percent of the time. This value (approximately 1,000 MW) represents the system baseload power needs. However, from a planning perspective, AE must have sufficient power generation capacity to serve its baseload, intermediate, and peaking needs (2,500 MW). Austin Energy's resource portfolio achieves this as AE has about 1,000 MW of baseload generation capacity, about 1,000 MW of intermediate capacity, and almost 500 MW of peaking capacity as represented by the generation stacks in Figure 6. In the ERCOT nodal market, AE no longer has a capacity and reserve requirement such that its capacity meets system load requirements. However, even in the nodal market, having enough generating capacity to meet load requirements is important as these assets act as a hedge against market prices. Figure 6 shows that AE's system peak occurs infrequently with system load exceeding 1,825 MW just 13 percent of the time. Intermediate load occurs over a significant amount of hours during the year. In 2009, 67 percent of operating hours fell into the intermediate category. During these hours, intermediate resources (in addition to baseload resources) were utilitized to meet AE's load, as indicated in Figure 6.

Under the BIP method approach, the utility must first determine the annual percentage of hours which are baseload, intermediate, and peaking, respectively as shown above.

Table 12 shows the number of hours and annual percentage of hours associated with each of these power generating unit categories for AE.

Table 12
Austin Energy Baseload, Intermediate, and Peaking Operating Characteristics

Time Period	Hours	Annual Percentage
Baseload	8,596	100%*
Intermediate	5,910	67%
Peaking	1,205	13%

*98% is for load, 2% represents excess generation

The BIP method allocates production costs to each customer class from a planning perspective, considering the economic cost of each unit and how and when these resources are used. Power generation resources are ranked from lowest to highest based on an understanding of each units' marginal operating cost. Power generation resources with the lowest marginal costs are assigned to system baseload periods, resources with intermediate marginal costs are assigned to intermediate and peak periods, and resources with the highest marginal costs are assigned only to system peak periods.

Once assigned to their respective periods, fixed baseload production costs are allocated to meet system average demand. Since system average demand is equivalent to system energy, these costs are allocated to each customer class based on total electricity consumed (measured in kWh). Fixed intermediate production costs are allocated to each customer class based on the coincident peak for each month of the year (12CP) since intermediate power generation resources are dispatched every month of the year to meet fluctuating loads. Fixed peaking production costs are allocated to each customer class based on the class contribution, or coincident peak, to each of the summer peak months of June, July, August, and September (4CP) since AE's peaking units are designed to operate only in times of peak demand.

Validation of BIP Method as the Recommended Approach

R. W. Beck is recommending the BIP method in lieu of the POD method due to changes in the ERCOT market making the POD method inadequate for production cost allocation. Given this recommendation, R. W. Beck believes that a transition to the BIP method for production cost allocation warrants further discussion.

As discussed previously, all power generating units in ERCOT are now dispatched to achieve the highest system efficiency and lowest costs for the ERCOT region as a whole, rather than having each utility make individual dispatch decisions on their own. If the AE load shape and the ERCOT load shape are similar, one might assume that the actual dispatch of AE units to benefit ERCOT as a whole would be very similar to the dispatch of AE units for itself. If this were the case, the POD method based on actual dispatch of AE units would be the same whether they were dispatched for ERCOT's cumulative benefit or for AE's lone benefit. Figure 7 compares the monthly peak demand of AE to the monthly peak demand of ERCOT. ERCOT is more than 20 times larger than AE is so the scales on the graph have been set to allow for visual comparison. The left y-axis correlates with AE's system peak demand and the right y-axis correlates with ERCOT system peak demand.

Figure 7
Austin Energy System Peak Compared to ERCOT System Peak

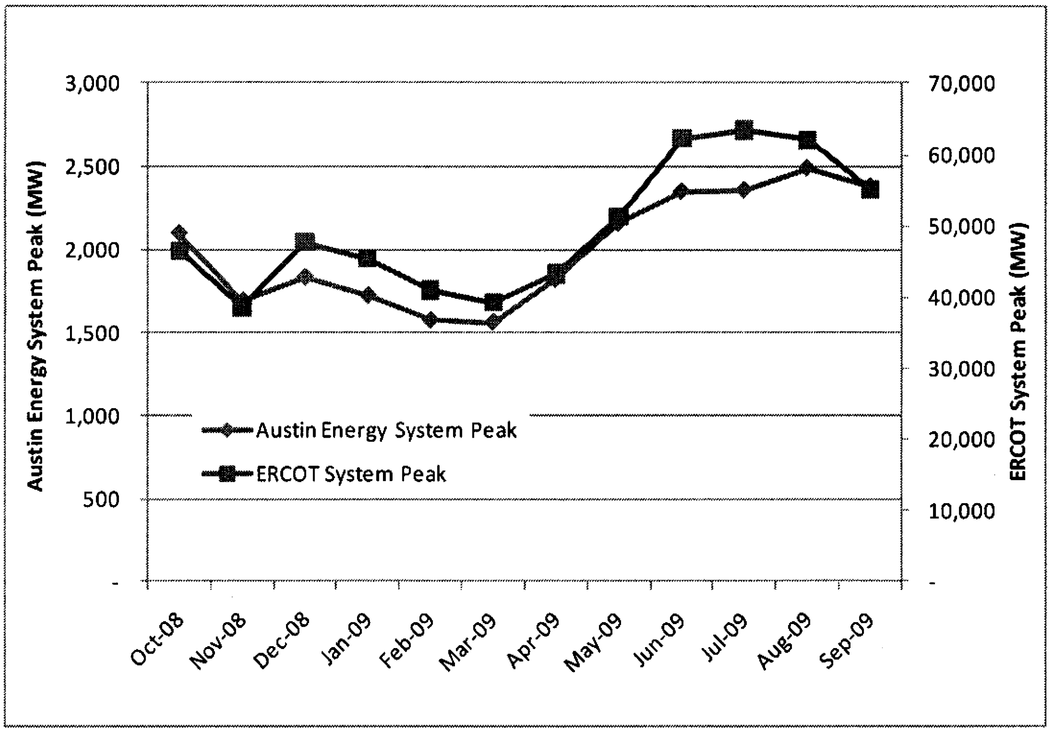


Figure 7 demonstrates that the ERCOT peak curve and the AE peak curve over the course of a year have a similar general shape, but the ERCOT system as a whole has relatively higher winter and summer peaks. In general, the AE curve is also flatter than the ERCOT system curve, as the market served by ERCOT experiences more extreme weather conditions than does AE. Given this high level overview of monthly system peak it is reasonable to assume that during many hours of the year the differences between ERCOT system-wide demand and AE system demand could be quite significant.

It should also be considered that the ERCOT market is comprised of numerous power generating units owned by many different entities. Many of these units have operating characteristics different from AE's units. Since AE operates its units within this system, other units can have an impact on when and how often AE's units are dispatched.

Under the ERCOT nodal market, the dispatched output of AE's power production units is sold into the market and AE receives payment for the energy based on the market-clearing price of energy at each node, or pricing point, in the system. Austin Energy pays the operating costs of its generating units to produce the energy requested by the ERCOT market and buys its energy needs from the market as needed. In this operating environment and market structure, AE's power generation units act as a hedge against market prices. For example, if AE did not own any production resources and simply purchased all its energy needs from the wholesale power market, it would have 100 percent exposure to variations in market prices. If prices are low, AE is able to buy power at that low cost, but if market prices spike, AE and its customers would be subject to the higher prices as well. This represents a high-risk operating strategy that could cause revenue instability for the utility and price instability for the utility's customers. Conversely, if AE has no need to purchase electricity to serve its customers, but still owned the production units, it would be at risk of not receiving sufficient revenues to fully cover its overhead costs if market prices were low.

Of the three methods examined, Peak Demand (4CP), AED, and BIP, the BIP method is the most similar to the POD method as the BIP method considers the timing, use, and cost of different generation resources and allocates such costs to customer classes based on each class' electricity usage characteristics. This method represents the varying use and value of AE resources in a nodal market. The primary difference between the BIP method and the POD method is an hourly versus peak period perspective for intermediate and peaking generation resources. The POD method analyses the generation supply stack for every hour of the year and matches this stack against customer class loads at each hour, resulting in an hourly allocation for all baseload, intermediate, and peaking generation resources. As previously discussed, the POD approach is no longer valid in the ERCOT wholesale market, as AE units are no longer dispatched just to cover AE's load. Therefore, the linkage between economic dispatch of generation and system load is broken. This disconnect may result in misleading and potentially highly variable class allocations depending upon market conditions at any given time of study. The BIP method provides cost allocation results with improved predictability and stability on a going forward basis while recognizing time-of-use cost differentials for the use of different generation resources. The BIP method allocates generation costs from a broader perspective, taking into consideration the economic value of generation in the broader context of the market and the price protection such resources provide to AE customers given market uncertainty.

The BIP method is a reasonable approach for production cost allocation given these considerations.

Transmission Demand Cost Allocation Methods

As discussed earlier, AE's transmission costs are regulated by the PUCT and represent a statewide average cost to customers. ERCOT allocates transmission charges to each utility that maintains a transmission system based on the utility's share of the summer peak demand within ERCOT. That share is computed using the 4CP method described earlier, which calculates the utility's average coincident system demand at the point of ERCOT system peak in each of the four summer months (June-September) as defined by ERCOT. These calculated transmission charges are then distributed among each AE customer class in a similar fashion. These demand-related charges regulated by the PUCT are allocated to each class based on that class' proportionate share of the 4 summer coincident peaks as defined by ERCOT. This creates a direct cause and effect relationship between assignment to AE of statewide transmission costs and allocation in turn among AE's customer classes.

Distribution Demand Cost Allocation Methods

Distribution systems are designed and built based on the demand of the areas they serve. Thus, it is logical to allocate these costs using a demand cost allocation method. The demand each customer class places on the distribution system (non-coincident peak) can be different than the class' demand at system peak (coincident peak). Distribution systems must be built to serve each non-coincident peak. For example, if a distribution substation and primary power lines serve a predominately residential area, the design, and therefore the costs, of the distribution equipment and facilities is driven by the Residential customer class non-coincident peak.

Demand allocators such as 1 NCP or 12 NCP take into account each customer class' non-coincident peak over the course of the year no matter when it occurs. Furthermore, as the distribution system gets closer to the ultimate customer, the size requirements, and therefore the costs, of the distribution equipment and facilities is driven by the peak of an individual customer. For instance, a service transformer must be built to serve the highest peak of the individual customer or customers it serves. A demand allocator known as the sum of maximum demands accounts for the individual customer highest demands placed on the system and will be used by AE in its COS study. The sum of maximum demands incorporates the total maximum demand by customer class and apportions each customer class total to the system total.

Production Energy Cost Allocation Methods

Energy allocation methods are used to allocate energy-related costs such as fuel and variable O&M at power plants. Compared to other types of allocation factors, energy allocation factors are relatively straightforward. Electricity consumption (measured in kWh) by customer class is readily available and is used in the development of these allocation factors. It should be noted, however, that the proper use of these factors should include consideration of line losses.

When transmitting and distributing electricity a certain percentage of energy is lost to resistance. In general, losses are estimated from the discrepancy between energy produced and energy sold to end-use customers. On average, system losses are around 5 to 7 percent. However, given the size of the ERCOT nodal market in relation to AE and variation among customer classes, this measure would be insufficient for a COS study. Net Energy For Load ("NEFL") represents the amount of energy that needs to be produced at the power plants to service the metered customer requirements. In order to accurately allocate NEFL to each customer class based on the portions of the delivery system utilized by each class, AE completed a loss study at three voltage levels. The purpose of the loss study is to determine the percentage losses that occur on the transmission system, the distribution primary system, and the distribution secondary system. Customers connected directly to the transmission system are only allocated transmission losses, customers connected to the primary distribution system are allocated transmission and distribution primary losses, and customers connected to the secondary distribution system are allocated losses for all three components.

With consideration of line losses, energy allocation factors should be developed at secondary, primary, transmission, and production voltage levels. In addition, timing adjustments are commonly made that take into consideration billing cycles and the mismatch between monthly billing data and power generation and purchased power information gathered at the system level. Each customer class' metered energy sales, adjusted for the proper level of losses depending on service voltage, are utilized to derive an NEFL energy allocation factor.

Customer Cost Allocation Methods

Customer allocation factors are used to allocate the portion of distribution costs and customer-related costs that are driven by the mere existence of a customer, whether they use any amount of energy or not. This accounts for certain fixed system costs such as meter investments as well as variable operating costs such as meter reading, billing, and collections. Customer allocation factors usually reflect customer-weighting factors that represent varying levels of effort or investment for each customer class. Some customer-related costs are simply allocated based on a total number of customers served – one customer is deemed to cost the same as any other customer – and other costs are based on weighting factors. Two common examples of weighted customer allocation factors are related to meter investment and customer billing and collection.

Meter investment is a function of the meter type installed and data gathering capabilities of that meter. Metering requirements can differ by customer class with the most expensive individual meters generally being used by large commercial and industrial customers. Therefore, to properly allocate meter investment costs to each customer class, customer weighting factors are developed to account for cost differentials in the metering equipment.

The cost of customer billing and collection also varies by customer class. Some customer types require additional effort for meter reading, data processing, and issuing a bill. This level of effort is considered in developing customer weighting factors for these costs.

Direct Assignment of Costs

Some costs can be directly assigned to a particular customer or customer class when it can be clearly determined that those costs relate only to that customer or customer class. For example, street lighting infrastructure costs are commonly assigned directly to that customer class.

Conclusions and Recommendations

Table 13 summarizes R. W. Beck's recommendations related to COS methodology and allocation methods as discussed in this paper.

Table 13
Summary of R. W. Beck Recommendations for Austin Energy Cost of Service Study

Preliminary Recommendation	Reasons for Consideration
Revenue Requirement Methodology	
Cash approach	The cash approach is widely adopted and used for municipal utilities and recognizes that a municipal utility operates on a cash basis and is a not for profit entity. The cash approach is consistent with AE's financial policies and bond covenants. Additionally, the cash approach is recognized by the PUCT in TCOS rulemaking.
Cost Allocation Methodology	
Allocation Method ▪ Unbundled Embedded Cost	Unbundled embedded cost methodology is widely used in the electric utility industry in general and is specifically used in Texas. This methodology is employed by the PUCT. Unbundling provides maximum understanding of the underlying cost causation and increased flexibility with respect to rate design.
Production Cost Allocation	
Demand Allocation Method ▪ Baseload, Intermediate, and Peaking (BIP)	BIP method appropriately recognizes the use and value of different types of generation capacity at different times during the course of the year. The method appropriately allocates costs to customer classes in both the traditional and nodal market environments.
Energy Allocation Method ▪ Net Energy for Load (NEFL)	NEFL is the industry standard for allocating energy to customer classes. This method recognizes the lower cost of providing energy to higher voltage customers due to reduced system losses.
Transmission Cost Allocation	
Demand Allocation Method ▪ ERCOT 4CP method	The ERCOT 4CP method is used by ERCOT in the allocation of transmission costs to AE. This approach directly aligns customer class electricity usage characteristics with cost incurrence.
Distribution Cost Allocation	
Demand Allocation Methods: ▪ 12 NCP - Substations Poles and	▪ The 12 NCP method allocates costs to customer classes based on the class maximum demand for each month of the year. This

Preliminary Recommendation	Reasons for Consideration
Conductors (Primary and Secondary) - Load Dispatch	approach recognizes that the distribution system is designed to meet class loads rather than system loads. 12 NCP is used to reflect varying class demands during the year. Load dispatch is allocated in a similar manner, reflecting the cost of operating the system to meet customer class demands.
▪ Sum of Max Demand - Transformer - Services (Primary and Secondary)	▪ Transformers and services are allocated based on the sum of maximum demands or billing demands for commercial customers with demand meters. This methodology reflects that transformers are sized to meet individual customer loads.
▪ Weighted Meters - Meters	▪ Meter costs are allocated to customer classes in consideration of the underlying investment. Weighting factors are developed for residential, commercial, and industrial meter installation.
▪ Direct Assignment - Streetlighting	▪ Streetlights are directly assigned to the Lighting customer class.
Customer Cost Allocation	
Customer Allocation Method ▪ Number of Customers - Customer Service - Customer Accounting - Meter Reading	▪ Certain costs of a customer function are allocated to each customer class based on the number of customers.
▪ Weighted Number of Customers - Uncollectibles - Key Accounts	▪ Using information from AE staff, weighting factors are developed to reflect varying levels of effort and cost responsibility of customer classes. Specific weighting factors are developed for uncollectibles and key accounts.

Interpreting Cost of Service Results and Next Steps

Austin Energy's revenue requirement is calculated based on financial records for Fiscal Year 2009 and adjusted to reflect a typical year through a process described in detail in this white paper. The utility's revenue requirement is then assigned to each of the utility's functional categories of production, transmission, distribution, and customer service to represent an unbundled COS. Within each function, the revenue requirement is classified as demand-related, energy-related, customer-related, or direct assignments. The revenue requirement is then spread across the customer classes based on cost allocations for each function and classification. This process has also been described in detail in this paper.

At PIC Meeting #3 preliminary results will be provided based upon preliminary COS analysis completed by R. W. Beck and reviewed by AE. Table 14 shows the template for providing preliminary results of AE's revenue requirement by customer class. PIC members and other members of the public are cautioned in advance that these COS results do not necessarily reflect the actual rates, or prices, that customers will pay. Rather, the COS results serve as a guide for ratemaking to help stimulate discussion and consideration of different rate structures. These preliminary results will show how much each customer class is currently paying for electric service under AE's existing rate structure compared to its cost of COS, demonstrating the divergence between the current revenues and COS results for each customer class.

While these preliminary results will give an indication of potential levels for rate adjustments for each customer class, the actual level and structure of rate adjustments is determined during the rate design phase. During the rate design phase, the potential application of tiered rates (based on level of electricity consumption) for residential customers, discounts for certain customers types such as low-income customers, and other rate design considerations will be discussed. Residential customer rate structures will be discussed at PIC Meeting #4 (scheduled for April 6) and commercial and industrial customer rate structures will be discussed at PIC Meeting #5 (scheduled for May 4).

Table 14
Results Template: Austin Energy Revenue Requirement by Customer Class

Test Year 2009
Cost of Service Summary Results Template

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Demand Related												
Base Load	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Intermediate	-		-	-	-	-	-	-	-	-	-	-
Peaking	-		-	-	-	-	-	-	-	-	-	-
Renewables	-		-	-	-	-	-	-	-	-	-	-
Subtotal Demand Related	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Energy Related												
Base Load	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Intermediate	-		-	-	-	-	-	-	-	-	-	-
Peaking	-		-	-	-	-	-	-	-	-	-	-
Renewables	-		-	-	-	-	-	-	-	-	-	-
Purchased Power	-		-	-	-	-	-	-	-	-	-	-
Subtotal Energy Related	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other												
Regulatory - Adj Clause	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Other	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Production	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission												
Demand Related												
Transmission - By Others	-		-	-	-	-	-	-	-	-	-	-
	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Transmission	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution												
Demand Related												
Primary - Subs, P&C	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Secondary - P&C	-		-	-	-	-	-	-	-	-	-	-
Transformers	-		-	-	-	-	-	-	-	-	-	-
Services	-		-	-	-	-	-	-	-	-	-	-
Load Dispatch	-		-	-	-	-	-	-	-	-	-	-
Subtotal Demand Related	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Related												
Meters	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Customer Related	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Direct Assignment												
Street Lights	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Direct Assignment	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Distribution	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer												
Customer Related												
Customer - Accounting	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer - Service	-		-	-	-	-	-	-	-	-	-	-
Meter - Reading	-		-	-	-	-	-	-	-	-	-	-
Uncollectibles	-		-	-	-	-	-	-	-	-	-	-
Key - Accounts	-		-	-	-	-	-	-	-	-	-	-
Subtotal Customer Related	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other												
Regulatory & Other	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Other			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Customer	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Cost of Service	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Appendix A
Austin Energy Abridged Financial Policies

- Debt and Debt Service
  - Debt shall not exceed the useful life of the asset and in no case shall the term exceed 30 years.
  - Debt service coverage of a minimum of 2.0X shall be targeted for the Electric Utility Bonds. All short-term debt, including commercial paper and non-revenue obligations, will be included at 1.0X.
- Reserve Funding Requirements
  - Austin Energy shall maintain either bond insurance policies or surety bonds issued by highly rated (AAA) bond insurance companies or a funded debt service reserve or a combination of both for its existing revenue bond issues.
  - Austin Energy shall maintain operating cash equivalent to 45 days of budgeted operation and maintenance expense.
  - A Repair and Replacement Fund shall be created and established. Money on deposit in the Repair and Replacement fund shall be used for providing extensions, additions, and improvements to the Electric System. Net revenues available after meeting the General Fund Transfer, capital investment (equity contributions from current revenues), and 45 days of working capital may be deposited in the Repair and Replacement Fund.
  - A fund named Strategic Reserve Fund shall be created and established, replacing the Debt Management Fund. It will have three components:
    - An Emergency Reserve with a minimum of 60 days of operating cash.
    - Up to a maximum of 60 days additional cash set aside as a Contingency Reserve.
    - Any additional funds over the maximum 120 days of operating cash may be set aside in a Competitive Reserve.
  - A decommissioning trust shall be established external to the City to hold proceeds for moneys collected for the purpose of the decommissioning of the South Texas Nuclear Project.
  - Current revenue, which does not include the beginning balance, will be sufficient to support current expenditures (defined as "structural balance"). However, if projected revenue in future years is not sufficient to support projected requirements, ending balance may be budget to achieve structural balance.
  - A non-nuclear plant decommissioning fund shall be established to fund plant retirement.
- Capital Structure

- Short-term debt, including commercial paper, shall be used when authorized for interim financing of capital projects and fuel and material inventories. The term of short-term debt will not exceed 5 years.
- Austin Energy shall maintain a quick ratio of 1.50X current assets less inventory divided by current liabilities.
- Capital Projects should be financed through a combination of cash referred to as pay-as-you-go financing (equity contribution from current revenues) and debt, a ratio between 35% and 60% equity contribution is desirable.

- Cash Funding Requirements
  - Ongoing routine, preventive maintenance should be funded on a pay as you go basis.
  - Net Revenue generated by AE shall be used for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies, and other AE requirements such as working capital.
- General Fund Transfer
  - The General Fund transfer shall not exceed 12% of AE's three-year average revenues, calculated using the current year estimate and the previous two year's actual revenues from the City's Comprehensive Annual Financial Report.
  - Electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to support:
    - The full cost (direct and indirect) of operations including depreciation;
    - Debt service;
    - General Fund Transfer;
    - Equity funding of capital investments;
    - Requisite deposits of all reserve accounts;
    - Sufficient annual debt service requirements of the Parity Electric Utility Obligations and other bond covenant requirements; and
    - Any other current obligations.

In addition, AE may recommend to Council in the proposed budget directing excess net revenues for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies, and other AE requirements such as working capital. In addition to these requirements, electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to ensure a minimum debt service coverage of 2.0X.

Appendix B
City of Austin Rate Covenant Required by Master Ordinance[1]

The City will fix, establish, maintain and collect such rates, charges and fees for electric power and energy and services furnished by the Electric Utility System and to the extent legally permissible, revise such rates, charges and fees to produce Gross Revenues each Fiscal Year sufficient: (i) to pay all current Operating Expenses; (ii) to produce Net Revenues, after (x) deducting amounts expended during the Fiscal Year from the Electric Utility System's Net Revenues for the payment of debt service requirements of the Prior First Lien Obligations and Prior Subordinate Lien Obligations and (y) taking into account ending fund balances in the System Fund to be carried forward in a Fiscal Year, equal to an amount sufficient to pay the annual debt service due and payable in such Fiscal Year of the then Outstanding Parity Electric Utility Obligations; and (iii) to pay after deducting the amounts determined in (i) and (ii) above, all other financial obligations of the Electric Utility System reasonably anticipated to be paid from Gross Revenues.

[1] City of Austin, Texas Official Statement, Electric Utility System Revenue Refunding Bonds, Series 2008A, page 6. July 24, 2008. Available online:
http://www.ci.austin.tx.us/finance/downloads/os_ae_rfg_08a.pdf

Glossary[2]

Capacity factor (net): The ratio of the net electricity generated, for the time considered, to the energy that could have been generated at continuous full-power operation during the same period.

Commercial Customer: Includes businesses such as retail stores, restaurants, and educational institutions with a peak demand of 50 kW or more during any twelve-month period. Small commercial customers may include businesses whose peak electric demand during any twelve-month period is less than 50 kW. Size classification may vary by utility. [For instance, AE defines commercial customers as any non-residential customer that is not an industrial customer.]

Congestion: The situation that exists when requests for power transfers across a Transmission Facility element or set of elements, when netted, exceed the transfer capability of such elements.

Congestion Zone: An area of the transmission network that is bound by commercially significant transmission constraints or otherwise identified as a zone that is subject to transmission constraints, as defined by an independent organization.

Cost of Service ("COS"): Studies designed to show how much individual customers should pay for the cost they impose on the system for the use of electricity.

Demand: The rate at which electric energy is delivered to or by a system at a given instant, or averaged over a designated period, usually expressed in kilowatt ("kW") or megawatt ("MW").

Electric Reliability Council of Texas ("ERCOT"): Refers to the independent organization and, in a geographic sense, refers to the area served by electric utilities, municipally-owned utilities, and electric cooperatives that are not synchronously interconnected with electric utilities outside the state of Texas.

Electric Utility: A person or river authority that owns or operates for compensation in this state [Texas] equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity.

Generation: Assets, activities, and processes necessary and related to the production of electricity. [Also referred to in this document as "production"]

Industrial Customer: Includes factories or manufacturing plants and typically have the highest demand for electricity.

[2] Chapter 25. Substantive Rules Applicable to Electric Service Providers. Subchapter A. General Provisions. §25.5 Definitions. www.puc.state.tx.us
ERCOT online glossary: www.ercot.com/glossary
Window of State Government, online Energy Glossary: www.window.state.tx.us/specialrpt/energy/glossary
Energy Vortex Online Dictionary: www.energyvortex.com/energydictionary
United States Nuclear Regulatory Commission: www.nrc.gov

Investor Owned Utility ("IOU"): Electric utility owned by stockholders who may or may not be customers. The IOU is a for-profit enterprise allowed to earn a pre-established rate of return for its shareholders and regulated by state public utility commissions.

Kilowatt ("kW"): A measure of electrical power equal to 1,000 watts.

Kilowatt hour ("kWh"): A quantitative measure of electric current flow equivalent to one thousand watts being used continuously for a period of one hour; the unit most commonly used to measure electrical energy, as opposed to kW, which is simply a measure of available power.

Line Losses: Difference between energy input into the Transmission Grid and the energy taken out of the Transmission Grid.

Load: a) the amount of energy used per hour or kWh or, b) the level of electricity demanded or kW.

Load Serving Entities ("LSEs"): An Entity that sells energy to Customers or Wholesale Customers and that has registered as an LSE with ERCOT. LSEs include Competitive Retailers (which includes REPs) and NOIEs that serve Load.

Load Size: a) the amount of energy used per hour or kWh; or, b) the level of electricity demanded or kW.

Market Clearing Price for Energy: The highest price associated with a Congestion Zone for a Settlement Interval for Balancing Energy deployed during the Settlement Interval.

Municipally-Owned Utility: Any utility owned, operated, and controlled by a municipality or by a non-profit corporation whose directors are appointed by one or more municipalities.

Megawatt ("MW"): The electrical unit of power that equals 1 million watts (1,000 kW).

Nodal Market: In the nodal market, the electric grid consists of more than 4,000 nodes, replacing the Congestion Management Zones that previously existed under the Zonal Market. The Texas nodal market is expected to deliver benefits such as improved price signals, improved dispatch efficiencies, and direct assignment of local congestion.

Peak Load or Peak Demand: Highest need of the system.

Plant-in-Service: Assets currently in use by the utility.

Public Utility Commission of Texas ("PUCT"): Formed in 1975 by the Texas Legislature as a rate regulatory body. The PUCT now, since deregulation, oversees electric and telecommunications companies to ensure Texas consumers have access to competitive utility services. The PUCT oversees competition in the wholesale and retail electricity and telecommunications markets, and regulates rates and services of non-competitive electric utilities and local exchange companies.

Public Involvement Committee ("PIC"): Committee comprised of 14 members representing different customer classes and community interests created to provide feedback regarding AE's rate review process.

Rate: A compensation, tariff, charge, fare, toll, rental, or classification that is directly or indirectly demanded, charged, or collected by an electric utility for a service, product, or commodity.

Rate Design: After the cost-of-service process is complete, the review process turns to rate design in which rate structures and rates, or prices, are determined.

Residential Customer: Includes private households that utilize energy for such needs as heating, cooling, cooking, lighting, and small appliances.

Revenue Requirement: Refers to the utility's total cost of servicing its customers.

Tariff: The schedule of a utility, municipally-owned utility, or electric cooperative containing all rates and charges stated separately by type of service, the rules and regulations of the utility, and any contracts that affect rates, charges terms, or conditions of service.

Transmission and/or Distribution Service Provider ("TDSP"): An Entity that is a Transmission Service Provider, a Distribution Service Provider, or both, or an Entity that has been selected to own and operate Transmission Facilities and has a PUCT approved code of conduct.

Transmission Service: Service that allows a transmission service customer to use the transmission and distribution facilities of electric utilities, electric cooperatives, and the municipally-owned utilities to efficiently and economically utilize production resources to reliably serve its load and to deliver power to another transmission service customer.

Wholesale: The sale of any commodity to a party who intends to resell that commodity to other parties is referred to as a wholesale transaction.

Wholesale Competition: Wholesale competition is a market structure in which retail companies have a choice of two or more suppliers from whom they can purchase the commodities that they resell to their customers.

Zonal Market: In the zonal market, the electric grid is divided into Congestion Management Zones, which are defined by Commercially Significant Constraints. Several limitations have been identified with the zonal market such as: insufficient price transparency, resources are grouped by portfolio, and the indirect assignment of local congestion.