BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	DOCKET NO. R-2014-2428743
v.	:	
PENNSYLVANIA ELECTRIC COMPANY	:	

DIRECT TESTIMONY

OF

CLARENCE L. JOHNSON

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

NOVEMBER 24, 2014

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Clarence L. Johnson. My business address is 816 Congress Avenue, Suite 1900, Austin, Texas 78701.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS YOUR CURRENT EMPLOYMENT?

A. I am self-employed as a consultant providing technical analysis, advice, and testimony regarding energy and utility regulatory issues.

Q. DO YOU HAVE PREVIOUS EXPERIENCE AS AN EXPERT ON REGULATED UTILITY MATTERS?

A. Yes. I have over 30 years of experience as a utility regulatory expert, including 25 years as director of regulatory analysis for the Texas Office of Public Utility Counsel ("OPC"). As a consultant, I have provided expert advice, assistance, and testimony on utility-related issues to a number of parties. My clients have included state consumer advocate offices, customer groups, and various coalitions of municipalities in Texas. Municipalities in Texas act as original jurisdiction regulators over electric utility rates within city boundaries.

Q. HAVE YOU PROVIDED AN ATTACHMENT WHICH DETAILS YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE?

A. Yes. Please see Appendix A.

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a B.S. in Political Science and a M.A. in Urban Studies from the University of Houston. My graduate degree is in an interdisciplinary program offered by the University of Houston's College of Social Science, which incorporated substantial training in economics, including course work in the application of cost-benefit analysis to public policy. During my 25-year tenure at OPC, I gained experience in virtually all phases of economic review required for the ratemaking process. I was chairman of the Economics and Finance Committee of the National Association of State Utility Consumer Advocates ("NASUCA") and served as a presenter for NASUCA's workshops and panels on cost allocation and rate design, demand-side management incentives, market power and electric utility competition. Also, at various times, I have undergone training in specific subjects, such as electric wholesale market design, cogeneration engineering and Electric Reliability Council of Texas ("ERCOT") operations.

I have previously filed testimony in more than 100 proceedings at the Public Utility Commission of Texas, Pennsylvania Public Utility Commission, and Connecticut Public Utility Regulatory Authority. With a few exceptions, the testimony has exclusively addressed electric rate issues.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS CASE?

A. FirstEnergy filed rate increase applications for each of its four electric distribution utilities ("Company" or "Companies") operating in Pennsylvania: Metropolitan Edison ("Met-Ed" or "ME"), Pennsylvania Electric ("Penelec" or "PN"), Pennsylvania Power ("PP"), and West Penn ("WP"). I have been asked by the OCA to address class cost allocation and rate design issues related to the Companies' applications for a rate increase. For purposes of reviewing those issues, I have utilized each Company's class cost of service study ("CCOSS"), which is based on each of the utility's proposed revenue requirement. My use of the filed costs should not be construed as agreement or acceptance of the Companies' requested revenues. Other witnesses retained by OCA will address the Companies' proposed revenue requirements. Because the Companies utilized common methodologies and principles to support their cost of service and rate design, my testimony addresses those issues together. To the extent that Company-specific issues are addressed, my testimony will identify the Company and provide specific discussion pertaining to that Company's particular issue.

Q. WHAT DOCUMENTS HAVE YOU REVIEWED IN PREPARING THIS TESTIMONY?

A. I reviewed relevant testimony and exhibits in each Company's rate filing. I also propounded numerous sets of interrogatories to each Company and reviewed the responses and accompanying information.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My recommendations are as follows:

- The Companies' CCOSS proposal to classify portions of poles, lines, underground plant, and transformers as customer-related should be rejected.
- The minimum grid study used to classify distribution plant in the CCOSS is flawed. My recommendation is to classify meters and services as 100% customer-related and the remaining distribution infrastructure as 100% demand-related. If the Commission is inclined to adopt a minimum system study, my alternative recommendation is to reduce the resulting customer classification percentage in order to eliminate double counting of demands.
- Uncollectible expense should be allocated on the basis of revenues, instead of customers as proposed by the Companies. Uncollectible expense is a general cost of performing business and should be recovered broadly across the customer classes.
- Except for the amount of any universal service expenditures which the Company can specifically identify, FERC Account 908, Customer Assistance, should be allocated on a class revenues basis instead of directly assigned to the residential class.
- FERC Account 910, Miscellaneous Customer Assistance and Information, should be allocated 50% on a customer basis and 50% on a class revenues basis.
- The CCOSS revisions, above, produce relative rates of return among the customer classes which diverge significantly from the filed results. For all four FirstEnergy Companies, the residential class CCOSS position changes from below average relative rate of return, as filed by the Companies, to significantly above average relative rate of return.
- The Companies' proposals to increase the residential monthly customer charge significantly should be rejected. My recommendation is to reduce the current residential customer charge for Met Ed, Penn Power, and Penelec. The increase in the West Penn customer charge should be limited to 25 cents.
- The CCOSS results are used only as a guide for distribution of the revenue increase among rate classes. The revenue increase recommended in my testimony recognizes the revised CCOSS results, as well as rate moderation. Classes with significantly below average rates of return receive a revenue increase capped at 150% of system average. The residential class receives a revenue increase below the system average increase.
- My testimony also discusses other rate design issues, including the storm damage charge rider, and rate impacts of the ME RT rate and the WP athletic field lighting rate.

III. CLASS COST OF SERVICE STUDY

A. Overview

Q. WHAT IS A CLASS COST OF SERVICE STUDY (CCOSS)?

A. The CCOSS is a fully allocated cost study which distributes the Company's costs to customer classes. The intent of the study is to allocate costs based on cost causation, generally resulting in a portion of costs allocated on causal measures and the remainder of indirect costs following those costs. The CCOSS is at best a broad benchmark for evaluating customer class cost responsibility. The CCOSS can provide guidance to the regulator, but considerations other than the CCOSS also are appropriate in determining the ultimate allocation of costs among customer classes. The CCOSS provides rates of return for each customer class at current and proposed class rates. Sometimes the class rates of return are divided by the total retail rate of return to arrive at a relative rate of return. The relative rate of return (or unitized return) may be used as a benchmark for guiding the direction of revenue changes at the class level. The CCOSS also provides class revenues based upon equalized rates of return (all classes' revenue produce the proposed overall retail rate of return). The class revenues at equalized rates of return can be used as a rough target for apportioning class revenue increases, but the results at equalized rates of return do not necessarily dictate the exact levels of class revenues. The class revenues may depart from equalized rates of return in order to recognize rate gradualism, relative risks associated with serving each class, or other non-cost considerations. However, the resulting revenues indicated by the CCOSS may provide

useful information regarding the equitable distribution of a system revenue increase among customer classes.

Q. HOW IS THE COST CAUSATION CRITERION APPLIED IN THE CCOSS?

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

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

The three major steps of the embedded cost of service study are functionalization, classification, and allocation. Functionalization is the procedure for separating costs into functional segments, such as generation, transmission, and distribution. The next two accounting steps, classification and allocation, facilitate the recognition of causation. The

classification procedure, which pools costs into general categories of causation (i.e., demand, customer, energy), is an intermediate step in determining the allocation factors that are used to divide costs among jurisdictions and customer classes. The allocation step determines the appropriate percentage of a particular FERC account which is attributed to each customer class.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THE DEVELOPMENT OF ALLOCATION FACTORS FOR DISTRIBUTION COST OF SERVICE STUDIES?

A. Yes. The principal external allocators in the Companies' studies are customer allocators and demand allocators. Customer allocators are based on class customer count as a percentage of total retail customer count. Sometimes weighting factors are applied to the customer count in order to reflect differences in cost per customer. For instance, meter reading customer allocators are weighted to reflect the differences in time required to read different types of meters.

The predominant demand allocation factor for the distribution systems is non-coincident peak demand (NCP). NCP is based on the maximum hour of demand for the class. Since classes incur peak demand in different time periods, the NCP method is said to reflect demand diversity on the system. Each class' demand allocator is the ratio of the class maximum kW demand relative to the sum of all classes' maximum demands.

Indirect costs in the CCOSS usually are allocated on the basis of internal allocation factors which "follow" the allocation of direct costs. An example is the labor allocator, which may be used to allocate administrative & general expenses; the labor

allocator will be driven by the labor portion of accounts which are classified as customer, demand, or both. A substantial portion of the customer and demand costs in the CCOSS will consist of indirect costs which are not inherently customer or demand related, but follow the customer/demand classification of other accounts. This explains in part why the results of a CCOSS frequently are sensitive to small changes in the customer/demand classification for certain accounts.

Q. PLEASE DESCRIBE YOUR REVIEW OF THE CCOSS PRESENTED BY EACH COMPANY.

A. I evaluated the studies for consistency and accuracy in the allocation of costs among classes. Based on my review, the allocation or classification of several cost elements were identified as insufficiently justified or warranting improvement. Each of these issues is common to the four utilities. My testimony proposes modifications to the treatment of those costs in each Company's CCOSS; the recommended modifications are discussed in subsections B through E, below. These changes affect my recommendations with respect to class revenue distribution. My recommendations focus on a limited number of CCOSS issues; omission of other issues should not be construed as agreement with all other aspects of the Companies' cost studies. The OCA does not agree with the proposed revenue requirements in the CCOSS; therefore, the revised versions of the CCOSS should be used only to examine class cost relationships rather than absolute revenue levels.

Q. DID YOU MODIFY EACH COMPANY'S CCOSS TO REFLECT YOUR PROPOSED REVISIONS?

A. Yes. The Companies provided OCA with live versions[1] of the CCOSS in excel format after execution of a confidentiality agreement; FirstEnergy considers the model, itself, to be confidential, but the output of the model is not confidential. After revising certain inputs in each of the four cost studies, the resulting modified CCOSS output is used in my rate design analysis to develop a recommended allocation of any proposed revenue increase for each Company among its customer classes.

B. Minimum Distribution Plant

Q. DO YOU AGREE WITH THE COMPANIES' ALLOCATION OF DISTRIBUTION PLANT INVESTMENT TO CUSTOMER CLASSES?

A. No. The Companies classify and allocate part of distribution plant investment in poles, lines, transformers, and underground facilities on the basis of number of customers. The Companies rely upon the concept of a minimum distribution system (which they label as minimum grid studies[2]) to support the classification of distribution infrastructure as customer-related. I will discuss this concept in more detail below. The Companies' proposed classification of poles, transformers, and lines as customer-related should be rejected because the jointly used distribution system is sized and designed to provide

[1] Confidential Responses: I&E-WP-RS-1-D Att. N; I&E-PN-RS-1-D Att. N; I&E-PP-RS-1-D Att. N; I&E-ME-RS-1-D Att. N.

[2] Exhibit HES-2, Study No. 7. Note that the term "minimum grid" is interchangeable with "minimum system."

adequate capacity to meet maximum demands.[3] The objective of distribution system planning is to provide reliable service; as a result, distribution facilities must be sized to meet the maximum demand that will be placed on the facility, and failure to do so can result in outages, burned out equipment, and voltage dropping outside of acceptable limits.

My recommendation opposes the classification resulting from the Companies' minimum grid study because: (1) the minimum distribution plant concept is inherently flawed and fails to reflect cost causation; (2) the Companies' application of the minimum system methodology overstates the amount of customer costs; (3) the methodology double counts demands and, therefore, over allocates cost to the residential class; and (4) the methodology was not applied in a complete fashion by the Companies. My testimony below will elaborate on these reasons.

Q. WHY DOES THE CUSTOMER VS. DEMAND CLASSIFICATION OF DISTRIBUTION FACILITIES PRODUCE SIGNIFICANT IMPACTS FOR THE RESIDENTIAL CLASS?

A. The residential class comprises the largest number of customers on the system, but has a relatively small usage per customer. For instance, the residential NCP demand allocation factor for the Companies is in the 50% range, while the residential customer allocation factor is close to 90%. This means that the customer classification will allocate roughly 40% more cost to the residential class than the demand classification.

[3] Notably Mr. Fullem's testimony directly ties higher levels of capital expenditures on the distribution system to the Companies' focus on maintaining reliability. Companies' Statement No. 1 at 13.

Q. WHAT PORTIONS OF ACCOUNTS 364-368 WERE CLASSIFIED AS CUSTOMER-RELATED BY THE COMPANIES?

A. The Companies' CCOSS splits distribution plant accounts into demand and customer classifications based on the ratio of minimum size component costs (as determined by the minimum grid study) to the account's average costs (adjusted for inflation). Consequently, the combined balance of secondary and primary voltage facilities are classified as customer-related, based on the percentages below.

Classification Customer Percentage[4]

	Metropolitan Edison	Pennsylvania Electric	Pennsylvania Power	West Penn Power
A364 Poles	78.0%	79.0%	84.5%	85.6%
A365 OH Conductors	84.1%	85.6%	91.1%	93.1%
A366-367 Underground	88.4%	79.7%	82.3%	85.6%
A368 Transformers	56.7%	68.2%	66.6%	77.1%

Some electric distribution utilities in Pennsylvania which utilize the minimum distribution method do not apply the customer classification to *both* primary and secondary voltage facilities. The FirstEnergy Companies' have chosen to apply the method to facilities at both voltage levels, even though the primary poles and lines tend to be larger in size and farther upstream from the end use customer.

Q. WHAT IS YOUR RECOMMENDATION?

A. My recommendation is to classify 100% of accounts 364 - 368 as demand-related, and classify 100% of services and meters as customer-related. I will discuss the reason for

[4] Met-Ed/Penelec/Penn Power/West Penn General Base Rate Filing. Exhibit HES-2 (Supporting Study No. 7 Primary/Secondary and Minimum Grid).

rejecting the customer classification for all facilities except services and meters in (1) through (4), below. My recommendation regarding customer classification is consistent with the following description of regulatory practice in a report prepared for the National Association of Regulatory Utility Commissioners (NARUC):

> The most common method [for apportioning distribution facilities between demand and customer] used is the "basic customer method" which classifies all wires, transformers, and poles as demand-related, and meters, meter reading, and billing as customer-related. This general approach is used by more than 30 states."[5]

The states' regulatory preference for the "basic customer method" is logical. Meters and service lines are located on or near the customer's premises. The remaining distribution facilities radiate outward from the customer's location and are part of an integrated electrical system which is designed and sized to support aggregations of load which may be nearly equivalent to the demand of the total system as the lines approach major substations. By establishing a clear demarcation for facilities classified as either 100% demand-related or 100% customer-related, the regulatory authorities avoid the complications associated with relying upon minimum distribution studies.

1. Conceptual Flaws in the Minimum System Method

Q. WHAT IS A MINIMUM DISTRIBUTION SYSTEM STUDY?

A. The minimum system study ("minimum grid study") attempts to develop the cost of a hypothetical distribution system with little or no load carrying capability. Because the minimum system, in theory, has minimal ability to carry electrical current, the analyst

[5] "Charges for Distribution Service: Issues in Rate Design," Regulatory Assistance Project, Dec. 2000, page 30, Weston, Harrington, Cowart, Moskovitz, and Shirley.

assumes that the costs are not demand-related and should be allocated on a customer basis. Most such studies either identify minimum size plant components or perform a statistical regression analysis to determine the hypothetical cost of a system which has zero load carrying capability. The nature of a minimum system study—developing a theoretical cost structure for a distribution system which is uninfluenced by demand—can produce a wide range of results, depending on the assumptions made by the analyst. Furthermore, the process of identifying zero or minimum load components is subjective and may lead to double-counting demands, as I will discuss later. In this case, the Companies used the minimum size study method, rather than using a zero intercept regression methodology.[6]

Q. WHY DO YOU QUESTION THE THEORY BEHIND A MINIMUM DISTRIBUTION SYSTEM?

A. The minimum distribution system concept introduces a theoretical cost to the study without any clear evidence that the hypothetical account is related to the number of customers. Dr. James Bonbright's critique of the minimum distribution system concept is frequently cited by cost analysts:

> [T]he annual costs of this phantom, minimum sized distribution system are treated as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs.... Their inclusion among the customer costs is defended on the ground that, since they vary directly with area of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary indirectly with the number of customers.

[6] The zero intercept method uses a statistical equation to project the price of a component if the size is extrapolated to zero load.

> What this last-named cost imputation overlooks, of course is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Indeed, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[7]

The implication of Dr. Bonbright's conclusion is that this "residual" cost of the distribution system (i.e. the cost ascribed to the customer classification) is not closely related to either demand or customer factors, but instead varies on the basis of less easily discerned geographic variables such as customer density.

Q. EVEN IF THE MINIMUM PLANT STUDY IDENTIFIES COSTS WHICH ARE NOT NECESSARILY DEMAND-RELATED, DOES IT FOLLOW THAT SUCH COSTS ARE CUSTOMER-RELATED?

A. No. My opinion is consistent with Dr. Bonbright's conclusion that the hypothetical minimum costs should be regarded as inherently unallocable:

> If the cost is neither demand nor customer related…to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs.[8]

As noted in the previous passage, the accuracy of a customer allocator is distorted by variations in spatial density among customers. A number of other factors, which are not clearly related to either customers or capacity (that is, demand), such as economies of scale in facility costs, component reliability, and objectives related to minimizing energy

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[7] JAMES C. BONBRIGHT, PRINCIPLES OF PUBLIC UTILITY RATES, Columbia University Press, 347-349 (1961).

[8] Bonbright at 347-349.

losses influence distribution costs. Dr. Bonbright's conclusion that the minimum system investment should be treated as "unallocable" is consistent with allocating those costs in proportion to the remaining allocable costs, a typical method for allocating costs without a clear causal basis. Because distribution investment is overwhelmingly allocable on a demand basis, classifying the residual minimum plant amount as demand-related achieves basically the same result.

Q. DO EMPIRICAL STUDIES SHOW THAT DISTRIBUTION COSTS VARY WITH CUSTOMERS?

A. No. Empirical analyses have reported that distribution plant and customer sales accounts are correlated with load density, but are not significantly affected by the number of customers served.[9]

Q. CAN YOU PROVIDE AN EXAMPLE OF THE EFFECT OF CUSTOMER DENSITY ON THE ALLOCATION OF THE COMPANIES' CUSTOMER-RELATED PLANT?

A. Yes. Line transformers provide an illustration, because the number of transformers per customer can vary significantly between classes and within a class. In applying the minimum grid to classify transformer costs, the Companies did not weight the customer allocation factors to recognize differences in the average number of transformers per customer for each class. The Companies state that one transformer typically serves 6 – 8 customers in a residential sub-division. In more dense residential areas, one transformer

[9] "Antitrust in the Electric Industry," by Leonard Weiss, *Promoting Competition in Regulated Markets*, Phillips, Almaric, Ed., The Brookings Institution (1975) at 145; "The Economics of Electric Distribution System Costs and Investments," by David Lessels, *Public Utilities Fortnightly*, Dec. 4, 1980 at 37-40.

may serve 10 – 25 residential customers. In rural residential areas, one transformer may serve 1 – 2 customers.[10] A larger commercial and industrial customer may be served by a single dedicated transformer because of the size of the load and the distance between properties. Among all retail customers, the Companies average approximately three customers per transformer. The Companies' allocation of a portion of transformer cost on the basis of customer count is inaccurate because it assumes that all customer classes are served by the same number of transformers per customer. To the extent that the residential class is served by fewer transformers per customer, the customer allocation will overstate the amount of minimum transformer cost attributed to the residential class. Similarly, customer density raises analogous issues with respect to feet of conductor per customer and number of poles per customer.

2. Application of Minimum Grid Method Overstates Minimum Costs

Q. EVEN IF ONE ACCEPTS THE MINIMUM SYSTEM CONCEPT, HAVE THE COMPANIES CORRECTLY APPLIED THE METHOD?

A. In my opinion, no. The manner in which the Companies have applied the method raises questions about the accuracy of the customer classification percentages and the identification of minimum size facilities. The first issue pertains to demand-related devices included in the FERC Accounts 364 – 368. The second issue is whether the minimum grid study represents actual minimum facility costs.

[10] OCA-ME-VIII-6, 7; OCA-PN-VIII-6, 7; OCA-PP-VIII-6, 7; OCA-WP-VIII-6, 7.

Q. PLEASE EXPLAIN HOW THE FIRST ISSUE RESULTS IN AN OVERSTATEMENT OF CUSTOMER CLASSIFICATION PERCENTAGES.

A. The Companies' minimum grid study develops customer percentages for FERC Accounts 364 – 368 based on the relative prices of poles, overhead conductors, underground cable, and transformers. These percentages are applied to all of the costs in the FERC account. However, other devices which are clearly demand-related[11] are also recorded in these accounts. As a result, these demand-related devices are incorrectly classified as partially customer-related. Capacitors, voltage regulators, and reactors are recorded in several accounts, including FERC Account 368; these devices are used to maintain the proper power factor and voltage on the distribution system. Faulted circuit indicators (FCI) and reclosers are devices recorded in FERC Accounts 365 and 367 which identify faults and isolate outages on the distribution system. These devices enhance the reliability of the system and, therefore, are demand-related. Application of the minimum grid percentages to the costs of these devices within those accounts will overstate customer costs. In order to correct this overstatement, customer percentages for overhead and underground conductors, and transformers should be reduced by 2% - 8%.[12] Schedule CJ-1 provides the percentages of devices by Company and shows the corrected customer percentage by account for each Company.

Q. DO YOU QUESTION WHETHER THE MINIMUM GRID STUDY PRODUCES RESULTS THAT REPRESENT ACTUAL MINIMUM COSTS?

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[11] Arguably a portion of these devices could be classified as energy-related since they affect reliability in all hours and not just peak hours. However, the important point is that the devices are not customer-related.

[12] OCA-PN-IV-11,12; OCA-PP-IV-11,12; OCA-WP-IV-11,12; OCA-ME-IV-11, 12.

A. Yes. The Companies' studies rely upon facility component sizes for the minimum system which are not actually minimum size. To some extent, this reflects the subjectivity of the minimum size methodology. In preparing a minimum distribution system study, utilities choose minimum size components based upon a wide range of criteria such as: (a) currently in use on the system; (b) currently purchased by the utility; (c) currently used within the electric utility industry; (d) available from electrical component suppliers; (e) currently required by safety codes; or (f) representing the current standard component of the utility. The criteria chosen will determine the size of minimum facilities, which in turn can produce significant swings in the percentages attributable to the customer classification. The Companies' practice of using larger standard sizes is inconsistent with the underlying rationale for the minimum system concept. The results are supposed to reflect purely the cost of access for a customer with little or no demand.

Some examples of minimum grid components which are not the smallest available size:

- The smallest conductor installed on the Companies' systems is 40% of the size, and 60% of the load carrying capability (measured in amps) of the overhead minimum conductor used in the Companies' minimum grid study.[13]
- Minimum size underground conductors in the study are sized 60% larger and provide 30% more load carrying capability (measured in amps), than the smallest underground conductor installed on the Companies' systems.[14]
- The Companies' Minimum Grid Study uses a 25 Kva transformer as the minimum size transformer. The smallest transformer on the Companies'

[13] OCA-ME-IV -1, 2; OCA-PP-IV-1, 2; OCA-PN-IV-1, 2; OCA-WP-IV-1, 2.

[14] Ibidem.

system is 3 Kva.[15] Other utilities have used minimum sizes of 3 – 5 Kva transformers in minimum system studies.

- The Companies' Minimum Grid Study uses 35 foot poles as the minimum components for Account 364. The study purposefully omitted poles of 20 feet or less in the Companies' data base from its analysis, implying that the Companies have installed much smaller poles in the past.[16] Although poles have no direct electrical load carrying ability, the size of poles is influenced by the size, weight and voltage of the conductors (which is related to demand capacity). A more reasonable 25 foot size pole costs 54% less than the 35 foot size used by the Companies, which indicates that the minimum grid cost for Account 364 could have been reduced significantly.

- Due to data limitations, the Minimum Grid Study used only primary poles and conductors—excluding secondary poles and conductors—to determine the minimum plant cost for all poles and conductors.[17] Thus, primary poles and conductors were utilized to determine the minimum cost of the *secondary* distribution plant. Because primary facilities are used at higher voltages and often are sized to carry larger aggregations of load, this will tend to overstate the minimum plant cost.

The Minimum Grid Study has not selected minimum size components based on the smallest available, or the minimum size used in the industry. This practice results in higher customer classification percentages.

Q. WHY DO YOU DISAGREE WITH THE COMPANIES' RELIANCE UPON "STANDARD SIZE" FACILITIES, IN LIEU OF SMALLER COMPONENTS, TO QUANTIFY THE MINIMUM GRID?

A. On a conceptual level, this approach is inconsistent with the underlying theory of the minimum system, because the facilities do not have minimum load carrying capability. In addition, a more significant problem is that the causal factors which affect the size of standard equipment cannot be attributed as customer-related. Factors which can affect

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[15] Ibidem.

[16] Met-Ed/Penelec/Penn Power/West Penn General Base Rate Filing, Exhibit HES-2 (Supporting Study No. 7 Primary/Secondary and Minimum Grid).

[17] Ibidem.

determinations of optimal standard size include economies of scale, efficiency considerations in procuring standardized sizes, the cost-effectiveness of installing excess capacity for future load growth, and the objective of reducing energy losses. However, these factors are not customer-related. In response to a question regarding planning criteria related to reduction of energy losses, the Companies cited their distribution planning guidelines:[18]

> ...the Company's Distribution System Planning Criteria, Section 6.1.2 – Sizing Overhead Conductors addresses the consideration of electric losses as follows:
>
> 6.1.2 Sizing Overhead Conductors
> When a conductor is to be installed or replaced due to projected overload or poor condition, several factors shall be considered when determining its optimum size: cost of losses, anticipated contingencies, impact on inventories or conductors, splices, clamps, and fittings, and availability of tools and dies. The latest Economic Wire Size Evaluation performed by the FE Distribution Standards Section in 2007 recommends the following optimum sizes based on initial loading under normal condition...

The Companies' practice of optimizing standard wire sizes in order to reduce energy losses is more closely related to energy and demand, rather than number of customers, as measures of cost causation.

3. Double-Counting Class Demands

Q. DO THE COMPANIES' MINIMUM SYSTEMS DOUBLE COUNT DEMAND?

A. Yes. The Minimum Grid Study did not use the smallest size components which results in a minimum system size which can accommodate substantial demands. As a result, a double-counting issue arises because customer class demands are reflected in the

[18] OCA-PP-IV-9; OCA-PN-IV-9; OCA-WP-IV-9; OCA-ME-IV-9.

allocation of both customer and demand-related investment. First, demands that can be served by the minimum size facilities are allocated to classes on a customer basis; second, all class demands, including the demand associated with minimum facilities, are used to allocate the demand portion of distribution facilities. The double counting of demand results in the over-allocation of costs to classes with a relatively low average use per customer (such as the residential class).

The NARUC Cost Allocation Manual acknowledges this issue and indicates that adjustments may be required for the demand allocation factors:[19]

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. *When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.*
>
> When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

The zero intercept methodology, which uses regression analysis to estimate the cost of facilities sized for zero demand, was developed in part to address this problem. The Companies do not use this method, nor do they adjust demands to correct the double counting.

[19] *NARUC Electric Utility Cost Allocation Manual* at 95 (emphasis added).

Q. IS THE DOUBLE-COUNTING ISSUE A SERIOUS DEFECT IN THE MINIMUM SYSTEM STUDY?

A. Yes. The demand carrying capability associated with minimum size components could, in theory, be deducted from the class demand allocation factors. A frequently cited article regarding the double-counting issue describes such an adjustment but concludes that a 100% demand classification is the more straightforward solution:[20]

> One way to solve the double allocation problem would be to determine, for each piece of minimum equipment, the demand level it would be capable of serving, and then adjusting the demand allocation factors used to allocate the costs of all equipment of that type in order to assure that minimum use customers and the residential class were not charged twice. In many cases this would mean calculating several allocation factors for each FERC distribution account, since more than one type of equipment is used in the account.
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> * * *
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> The direct way to assure that problems of overcollection are not built into the methodology used to determine class costs of service is to classify all distribution costs as demand costs. If this methodology is used in embedded cost studies, the studies produce more equitable estimates of the cost of serving low-use residential customers.

My recommendation is consistent with the conclusion that distribution infrastructure costs should classified as demand-related, rather than customer-related.

Q. ARE YOU AWARE OF ANY OTHER METHODS FOR ESTIMATING THE MAGNITUDE OF THE DOUBLE-COUNTING ADJUSTMENT?

A. Yes. Some analysts contend that limiting the minimum size costs to the labor installation portion of the minimum cost is appropriate in order to avoid double-counting. The labor

[20] "The Customer Charge and Problems of Double Allocation of Costs," George Sterzinger, Public Utilities Fortnightly, page 31 (July 2, 1981).

portion of the facility cost is considered relatively fixed, and removing the material component eliminates the portion most relevant to demand carrying capability. The premise of this method is that the minimum plant's load carrying capability is principally confined to the material cost, since labor costs would be incurred regardless of the load size. The labor percentages, below, can be multiplied by the account customer percentage to determine the reduction in customer classification if the minimum size component is limited to labor costs. The Companies state that the following labor installation percentages are associated with the minimum components:[21]

Labor Percent For Minimum Components

POLES	54.4%
OH CONDUCTORS	66.7%
UG CONDUCTORS	16.0%
TRANSFORMERS	26.3%

Schedule CJ-2 provides customer classification percentages adjusted to reflect only the labor component for minimum size plant. Schedule CJ-4 provides the summary of CCOSS results at Current Rates based on correcting double-counting of demand.

4. Companies' Minimum Distribution System is Incomplete

Q. WHY DO YOU CONTEND THAT THE COMPANIES' MINIMUM SYSTEM STUDY IS INCOMPLETE?

A. The Companies classify 100% of services (Account 369) as customer-related. I agree with the classification *if* the minimum system study is *not* applied to distribution facilities. However, if a minimum system study is used, the method should be applied in a symmetric fashion to service conductors, which are ordinarily classified as customer-

[21] OCA-ME-IV-1(e); OCA-PP-IV-1(e); OCA-PN-IV-1(e); OCA-WP-IV-1(e).

related. The minimum system concept attempts to divide facilities into percentages of cost that are demand and customer-related. Just like overhead conductors, different sizes of service lines have varying load carrying capability, and a complete application of the minimum system approach would recognize that part of the services cost is demand-related. The incorporation of a demand classification for services would reduce the overall customer classification amount within the Companies' cost of service study.

Q. DOES THE NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL'S DESCRIPTION OF THE MINIMUM DISTRIBUTION SYSTEM RECOGNIZE THAT PART OF SERVICES SHOULD BE CLASSIFIED AS DEMAND?

A. Yes. The minimum size method, according to the NARUC Cost Allocation Manual, "involves determining the minimum size pole, conductor, cable, transformer *and service* that is currently installed by the utility."[22]

Q. IF THE COMPANIES HAD APPLIED THE MINIMUM SYSTEM STUDY IN A COMPLETE MANNER, WOULD A PORTION OF SERVICES BE CLASSIFIED AS DEMAND-RELATED?

A. Yes. This, in turn, would reduce the amount of costs classified as customer-related in the CCOSS.

5. Conclusion

Q. WHAT IS YOUR CONCLUSION REGARDING THE MINIMUM SYSTEM STUDY?

[22] NARUC Electric Utility Cost Allocation Manual (1992) at 90 and 92. (Emphasis added).

A. My recommendation is to disregard the results of the Companies' minimum system plant study. The customer classifications for distribution plant other than services and meters should be replaced by a demand classification in the CCOSS. In the alternative, if the Commission decides to implement a minimum system concept, my recommendation is to revise the customer classification based on the labor portion of minimum plant as shown on Schedule CJ-2.

Q. DOES ELIMINATING THE MINIMUM SYSTEM GRID PRODUCE A SIGNIFICANT IMPACT ON THE COST POSITION OF THE RESIDENTIAL CLASS?

A. Yes. The table below shows the impact on residential rates of return at present rates, based on the Companies' claimed revenue requirement.

Residential ROR at Present Rates

	System	Per Company	Unitized	No Minimum Grid	Unitized
PP	3.98%	3.45%	87%	6.70%	168%
ME	2.10%	1.49%	71%	3.27%	156%
PN	4.01%	3.08%	77%	6.51%	162%
WP	4.78%	3.67%	77%	8.58%	179%

The unitized column is an index called relative rate of return and shows the class rate of return as a percentage of the system rate of return. The residential relative rate of return shifts from below average to well above average due to the elimination of the minimum grid. The residential relative rate of return is also above average under my alternative recommendation.

Q. DO YOU HAVE A SCHEDULE QUANTIFYING THIS ISSUE?

A. Yes. Schedule CJ-3 summarizes the results of the Companies' CCOSS at current rates with the elimination of the minimum system. Schedule CJ-4 summarizes the results of the Companies' CCOSS at current rates if the customer classification percentages are adjusted based on my alternative recommendation.

C. Uncollectible Expense (Bad Debt)

Q. HOW DO THE COMPANIES ALLOCATE UNCOLLECTIBLE EXPENSE?

A. The Companies assign uncollectibles (FERC Account 903) on the basis of a customer allocator. 88% - 90% of the cost is assigned to residential customers.

Q. DO YOU RECOMMEND MODIFYING THAT ALLOCATION?

A. Yes. I recommend an allocation of uncollectible expense on the basis of class revenues. This cost is an indirect cost which should be spread broadly across the customer base.

The NARUC Electric Utility Cost Allocation Manual states that uncollectible expense is an *exception* to the allocation of customer accounting expense on a customer basis. The Manual states that some utilities directly assign the cost, and continues:[23]

> Some analysts would prefer to regard uncollectible accounts as a general cost of performing business by the utility and would classify and allocate these costs based upon an overall allocation scheme, such as class revenue responsibility.

Q. IS THIS EXPENSE APPROPRIATELY ALLOCATED BASED ON THE NUMBER OF CUSTOMERS?

A. No. The magnitude of the uncollectible expense in a given period is affected not only by the number of customers on the system, but also by the amount of revenue billing attributable to each particular type of customer. In addition, the *potential* for significant

[23] NARUC Electric Utility Cost Allocation Manual at 103.

impact from individual large accounts should be considered. For instance, if an industrial or large business customer goes out of business due to bankruptcy, that individual default would result in a disproportionate increase in the amount of uncollectible expense. Although the event may not occur in the specific test year, the uncollectible allowance should reflect that possibility. An allocation which recognizes the relative size of bills recognizes the potential for such outcomes. A revenue allocator is a reasonable means of incorporating that consideration. The Texas PUC adopted my recommendation regarding this cost in an Entergy case, with the reasoning explained below:[24]

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

Q. WHAT IS THE RATIONALE FOR A REVENUE ALLOCATION?

A. As recognized in the finding quoted above, uncollectibles should be allocated broadly because a narrow assignment does not allocate the expense to cost causers, because the non-payors, by definition, are not paying customers. As noted above, the costs will be borne by customers who dutifully pay their bills, and therefore should be treated as a general cost of doing business. An allocation in proportion to class revenues is a fair method to accomplish this objective.

[24] Public Utility Commission of Texas, Second Order on Rehearing, Finding of Fact No. 231, *Application of Entergy Gulf States Utilities Co. for a Rate Increase*, Docket No. 16705 (1998).

D. Customer Assistance and Information Accounts No. 908 and 910

Q. WHAT IS INCLUDED IN ACCOUNT 908, CUSTOMER ASSISTANCE AND INFORMATION EXPENSE?

A. The object of this account is to advise and educate customers on the safe and efficient use of electricity. These costs can include responding to customer inquiries and preparing bill inserts. The Companies' administrative costs for universal service and energy conservation program are recorded in the account. However, the Company did not specifically quantify the portion of this account specifically attributable to universal service and energy conservation.

Q. HOW DO THE COMPANIES ALLOCATE ACCOUNT 908?

A. The Companies directly assign the entire expense to the residential class.

Q. DO YOU AGREE WITH THIS DIRECT ASSIGNMENT?

A. No. The FERC account description is not consistent with directly assigning the expense to the residential class. The examples of expenditures provided in the FERC chart of accounts indicates that a number of general activities, which could be characterized as sales or customer relations-related, are recordable in the account:

> 2. Processing customer inquiries relating to the proper use of electric equipment, the replacement of such equipment and information related to such equipment.
>
> 3. Advice directed to customers as to how they may achieve the most efficient and safest use of electric equipment.
>
> 4. Demonstrations, exhibits, lectures, and other programs designed to instruct customers in the safe, economical or efficient use of electric service, and/or oriented toward conservation of energy.

5. Engineering and technical advice to customers, the object of which is to promote safe, efficient and economical use of the utility's service.

6. Supplies and expenses pertaining to demonstrations, exhibits, lectures, and other programs.

Q. IS THERE EVIDENCE THAT SOME EXPENSES INCLUDED IN ACCOUNT 908 ARE AIMED AT NON-RESIDENTIAL CUSTOMERS?

A. Yes. Each of the Companies record the cost of customer support personnel to Account 908. The customer support departments include personnel who are primarily involved with commercial and industrial customers and street lighting customers.[25] These personnel also may be involved in preparing rate studies, investigating outages, and making rate suggestions.[26]

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO ACCOUNT 908?

A. My recommendation is to allocate these costs on the basis of class revenues. Direct assignment of the total account expense to the residential class is inappropriate, and a general allocator reasonably spreads the expense across the customer base. If the Company can isolate the amount for support of universal service (not recoverable through the universal service rider), that amount should be directly assigned, with the remainder allocated on a revenue basis.

Q. WHAT IS ACCOUNT 910, MISCELLANEOUS CUSTOMER INFORMATION EXPENSE?

A. The FERC account description states:

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[25] OCA-ME-XIII-1, 2; OCA-PP-XIII-1, 2; OCA-PN-XIII-1, 2; OCA-WP-XIII-1, 2.

[26] Ibidem.

> This account shall include the cost of labor, materials used and expenses incurred in connection with customer service and informational activities which are not includible in other customer information expense accounts.

It appears that a portion of the account includes call center costs incurred by the Companies.

Q. HOW DO THE COMPANIES ALLOCATE ACCOUNT 910?

A. The Companies use a weighted customer allocation. The customer allocation is weighted by the percent of call center calls associated with particular customer classes. In some cases, the weighted allocation (as high as 97%) to the residential class exceeds the allocation associated with a customer count allocator.

Q. DO YOU AGREE WITH THE COMPANIES' USE OF CALL CENTER CALLS TO ALLOCATE ACCOUNT 910 EXPENSE?

A. No. The rate class and subject matter related to a large proportion of calls are unknown because they involve the interactive voice response system. The number of these calls can approach or exceed the majority of calls.[27] A substantial number of calls involve reports of outages, and it is not obvious why the customer's rate class should affect the allocation of this cost.[28] Customers should be encouraged to report outages because it enables the utility to repair equipment more quickly, which can benefit other customers. The call may also include inquiries regarding customer choice or other general issues which are more appropriately allocated on a broad basis. Also, the number of calls by class does not reflect the average minutes per call for each class, which can vary due to

[27] Attachment to OCA-ME-IV-14; Attachment to OCA-PP-IV-14; Attachment to OCA-PN-IV-14; Attachment to OCA-WP-IV-14.

[28] Ibidem.

the complexity of billing or other issues. Furthermore, the nature of any non-call center expenses reported in this account are not clear.

Q. HOW DO YOU RECOMMEND ALLOCATING ACCOUNT 910?

A. I propose allocating one half of the account on a revenue basis and the remainder on a customer basis. This recognizes that part of the call center operation is allocable to customers, but that a portion of costs in this account are reasonably allocated broadly across the customer classes.

E. CCOSS Conclusion

Q. HAVE YOU QUANTIFIED THE IMPACT OF YOUR RECOMMENDED ADJUSTMENTS TO THE CCOSS?

A. Yes. Schedule CJ-5 sets forth the revised CCOSS results for each Company. I have included summary sheets which show the class rate of return at present rates and the increase/decrease in revenues compared to the Company's filing at equalized rates of return, which is the hypothetical scenario for moving classes directly to the cost of service revenue levels. As noted previously, OCA does not agree with the Companies' proposed revenue requirement in these CCOSS computations, so the results of these schedules should be viewed as a general guide for class cost relationships rather than a reflection of the actual revenue levels which will be adopted in this case. A comparison of the rates of return (ROR) and relative rates of return (RROR or unitized return) based on the Companies' and OCA CCOSS are shown below. The succeeding step, allocating the revenue increase, will be discussed in Sec. V, as part of rate design.

Penelec

	RS	GSV	GSS	GSM	GSL	GP
ROR Per OCA	7.2%	4.7%	1.1%	1.9%	-0.2%	2.8%
RROR Per OCA	180.3%	116.4%	27.2%	47.6%	-4.4%	70.4%
ROR Per Company	3.1%	10.8%	-1.5%	13.6%	11.9%	1.0%
RROR Per Company	76.9%	268.9%	-38.1%	340.3%	297.9%	25.6%

	LP	BRD	H	POL	STLT
ROR Per OCA	0.1%	8.6%	1.5%	11.8%	-4.0%
RROR Per OCA	1.7%	215.7%	38.1%	295.7%	-99.4%
ROR Per Company	5.0%	20.7%	15.9%	11.3%	-3.8%
RROR Per Company	123.7%	516.6%	396.2%	283.3%	-94.9%

As shown above, the residential relative rate of return produced by my revision is more than twice the comparable ratio produced by the Company's study.

Penn Power

	Res	GSR	GSS	GSM	GSL	GP
ROR Per OCA	7.17%	4.4%	5.1%	0.6%	-1.2%	-5.6%
RROR Per OCA	180.19%	109.6%	127.7%	14.1%	-30.7%	-141.5%
ROR Per Company	3.45%	8.5%	0.7%	11.1%	10.8%	-5.3%
RROR Per Company	86.81%	212.8%	16.8%	278.5%	272.4%	-132.3%

	OH	PNP	POL	STLT	GT
ROR Per OCA	-1.3%	2.2%	1.3%	4.7%	21.6%
RROR Per OCA	-33.4%	56.3%	32.3%	116.9%	542.5%
ROR Per Company	6.1%	6.8%	-0.9%	6.9%	24.7%
RROR Per Company	154.4%	170.7%	-23.7%	173.6%	621.4%

As shown above, the residential relative rate of return produced by my revision is almost 100 points higher than the comparable ratio produced by the Company's study.

Met-Ed

	RS	GSV	GSS	GSM	GSL	GP
ROR Per OCA	3.8%	3.8%	3.2%	0.4%	-2.6%	-1.0%
RROR Per OCA	181.1%	179.0%	149.8%	21.1%	-125.6%	-49.3%
ROR Per Company	1.5%	11.5%	-1.5%	9.1%	3.3%	-1.1%
RROR Per Company	70.7%	548.3%	-71.4%	432.5%	154.7%	-50.7%

	TP	BRD	MS	POL	STLT
ROR Per OCA	-4.1%	2.9%	3.8%	2.1%	5.9%
RROR Per OCA	193.2%	139.6%	179.9%	98.5%	279.6%
ROR Per Company	0.0%	2.8%	16.3%	1.9%	8.5%
RROR Per Company	-0.5%	135.3%	775.8%	88.5%	406.3%

As shown above, the residential relative rate of return produced by my revision is more than 100 points higher than the comparable ratio produced by the Company's study.

West Penn

	RS	GS10	GSS	GSM	PP40	GSL
ROR Per OCA	8.7%	6.7%	-0.6%	5.2%	507.1%	1.7%
RROR Per OCA	181.6%	139.5%	-13.5%	108.9%	10615.0%	36.4%
ROR Per Company	3.7%	12.1%	-4.0%	15.4%	-1.4%	11.4%
RROR Per Company	77%	254%	-83%	322%	-29%	238%
	POL	**PSU**	**PP44**	**PP46**	**AGS**	**STLT**
ROR Per OCA	36.8%	194.1%	-4.2%	251.0%	21.9%	4.0%
RROR Per OCA	769.8%	4063.0%	-87.3%	5253.7%	457.9%	83.4%
ROR Per Company	20.2%	6.5%	-4.2%	-0.8%	21.7%	5.0%
RROR Per Company	423%	136%	-87%	-16%	454%	104%

As shown above, the residential relative rate of return produced by my revision is more than 100 points higher than the comparable ratio produced by the Company's study.

Q. IS THE WEST PENN CCOSS AFFECTED BY ERRORS?

A. Late in the discovery process, West Penn reported several errors in its CCOSS spreadsheet.[29] Since my results are based on West Penn's model, those errors may have affected the results shown, above, for West Penn. The Company's response did not provide a corrected "live" excel workbook, and did not provide sufficient information for me to correct the errors. However, based on the discovery response provided by West Penn, the effect of the errors are small. My review indicates that the errors are unlikely to change the overall conclusions of the CCOSS results presented above. I reserve the right, however, to revise my conclusions in later testimony once the Company submits a corrected live excel workbook.

[29] OSBA-WP-I-2.

IV. RESIDENTIAL CUSTOMER CHARGE

Q. WHAT ARE THE COMPANIES' PROPOSALS REGARDING RESIDENTIAL CUSTOMER CHARGE?

A. Each of the Companies propose a substantial percentage increase in residential customer charges. The proposals are shown below.

Companies' Proposed Customer Charge Increases

	Current	Proposed	Percent Increase
ME	$8.11	$13.29	64%
PN	$7.98	$11.92	49%
PP	$8.89	$12.71	43%
WP	$5.00	$7.35	47%

Q. DO YOU AGREE WITH THE PROPOSALS TO RAISE THE CUSTOMER CHARGE?

A. No. The customer charge does not provide price signals which are particularly relevant to resource allocation. In the ratemaking process, the customer charge level is closely linked to the utility's usage rates (per kWh and per kW), since costs which are not collected through the customer charge will be recovered through the usage rates. Because the electric utility cost structure is dominated by costs which vary with changes in demand and annual electric load over the long run, the usage-sensitive rate is the primary source of meaningful price signals. A lower customer charge ensures that a greater proportion of costs are recovered through a usage-sensitive price. A lower customer charge is more consistent with energy conservation goals and provides pricing policies appropriate for consumption of finite natural resources. In addition, a policy that minimizes the customer charge is more equitable to low usage and low income residential

customers. OCA witness Colton will address the impact of the customer charge on low income customers.

Q. WHAT IS THE APPROPRIATE BENCHMARK FOR SETTING THE CUSTOMER CHARGE?

A. In my view, the customer charge should only recover costs which directly vary with the number of customers. The only economic pricing function of a customer charge is to ration access to the utility system; and public policy favors expansion, rather than limitation, of public access to regulated monopoly essential service. There is ample reason to base the customer charge on the following components: O&M expense for meters, services, meter reading, and customer accounting, and return and depreciation on meter and service investment, minus credits for customer deposits and related deferred federal income taxes. In my view, general overhead, such as administrative and general expense, and customer classified costs which are only weakly related to customer count, should be excluded from the customer charge computation, because these costs do not vary directly with number of customers.

Q. IS YOUR VIEW OF THE APPROPRIATE CUSTOMER CHARGE BENCHMARK CONSISTENT WITH THIS COMMISSION'S PRACTICE?

A. My understanding is that the Commission historically favored a "basic customer cost" composed of costs for meter/service drops, meter reading, and billing.[30] This is a reasonable benchmark for the scope of costs included in the customer charge.

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[30] *See e.g. Re: West Pennsylvania Power Co.*, 69 PUR4th 470 (1985); *Re: West Pennsylvania Power Co.*, 119 PUR4th 110 (1990).

Q. HAVE YOU CALCULATED CUSTOMER CHARGES BASED ON YOUR APPROACH, WHICH LIMITS THE COSTS TO COMPONENTS WHICH VARY DIRECTLY WITH CUSTOMERS?

A. Yes. My calculation of the basic customer charge is shown below.

Utility	Current Customer Charge	Per OCA Analysis
ME	$8.11	$6.29
PN	$7.98	$4.83
PP	$8.89	$6.57
WP	$5.00	$5.24

With the exception of West Penn, the calculated basic customer charge is substantially less than the current customer charge. And, in the case of West Penn, the calculated charge is only 24 cents more than the current charge. Details of the calculation are shown on Schedule CJ-6.

Q. PLEASE DESCRIBE THE SPECIFIC COMPONENTS OF YOUR CUSTOMER CHARGE CALCULATION.

A. The following expense accounts are included: meter O&M expense, customer accounting excluding uncollectibles, meter and services depreciation, accelerated depreciation for legacy meters, amortization of smart meters, and a portion of Account 910 call center cost.[31] A rate base component is comprised of net meter and service plant and deductions for customer advances and deposits. The return reflects both equity and debt rates and the federal and state income tax rates. I have used the rate of return recommended by OCA witness Griffing. The call center component is limited to billing, which I estimated

[31] Attachment A, OCA-ME-IV-14; Attachment A, OCA-PN-IV-14; Attachment A, OCA-PP-IV-14; Attachment A, OCA-WP-IV-14; OCA-ME-IV-13; OCA-PN-IV-13; OCA-PP-IV-13; OCA-WP-IV-13.

by calculating the residential billing calls as a percent of all calls. In my view, the inclusion of accelerated depreciation is a conservatism, since it reflects early retirement costs rather than the incremental cost of adding customers. I could not quantify a deduction for deferred taxes associated with services and meters, which results in a rate base slightly higher than I would normally utilize.

Q. HAVE THE COMPANIES UTILIZED THE SMART METER SURCHARGE AS A JUSTIFICATION FOR THEIR CUSTOMER CHARGE INCREASE?

A. In order to justify the proposed percentage increase in customer charge, each of the Companies, except for West Penn (which has a kWh smart meter charge), points to a current customer charge level which is the sum of the smart meter surcharge and the base rate customer charge.[32] However, I disagree with this rationale. The smart meter surcharge was intended as a temporary collection method with the objective that the costs would eventually be rolled into the base rate cost of service. In addition, the actual savings (for meter readers, for example) should be reflected in the base rate cost of service. The surcharge includes components for administrative and general expense and general plant which may or may not link to costs in the test year, but which are not recoverable through the customer charge. Thus, the surcharge amount should not be accepted as the appropriate charge for a base rate calculation. The Companies seek to roll-in the smart meter surcharge costs into base rates in this case. Thus, the appropriate benchmark for the customer charge should be based on the appropriate costs included in the cost of service, since those costs incorporate the roll-in amount. My customer charge

[32] OCA-ME-VIII-14; OCA-PP-VIII-14; OCA-PN-VIII-14.

calculation is based on costs derived from the cost of service study, which include the roll-in amounts.

Q. HAVE THE COMPANIES PROVIDED OTHER CALCULATIONS INTENDED TO JUSTIFY THE CUSTOMER CHARGE INCREASE?

A. Yes. Each of the Companies provides a calculation of residential customer costs from the CCOSS.[33] Both a total customer cost amount and a total amount excluding minimum grid customer costs are provided by the Companies. As described previously in my testimony, the customer percentages derived from the minimum grid should not be included in the CCOSS. Given the fact that the Companies provide and reference a customer cost calculation without minimum grid costs, they do not appear to suggest that the benchmark should include minimum grid costs (which would produce extremely high customer charges). A comparison of the Companies' requested customer charge and the Companies' calculation of customer costs (excluding minimum grid) is shown below.

Proposed Customer Charge vs. Company Calculation

	Proposed	Calculated Cust Cost	Difference
Met-Ed	13.29	14.06	0.77
PN	11.92	10.67	-1.25
PP	12.71	11.57	-1.14
WP	7.35	8.61	1.26

As shown in the table, Penn Power and Penelec request customer charges in excess of the customer charge calculation, while Met-Ed and West Penn produced customer charge calculations in excess of the proposed customer charges.

[33] Attachment to OCA-ME-VIII-14; Attachment to OCA-PP-VIII-14; Attachment to OCA-PN-VIII-14; Attachment to OCA-WP-VIII-14.

Q. DO YOU AGREE WITH THE CUSTOMER CHARGE CALCULATION PROVIDED BY THE COMPANIES?

A. No. The calculation includes customer classified costs which do not vary directly with the number of customers. Such indirect costs include portions of administrative and general expense, general plant, and customer assistance and information expenses, which are only weakly related to customers, if at all. In my view, the Companies' customer charge calculation is not consistent with a basic customer charge concept.

Q. DO POLICY REASONS FAVOR THE USE OF THE BASIC CUSTOMER CHARGE CALCULATION?

A. Yes. In weighing the appropriateness of limited or broad calculations of the customer charge, the Commission should consider the effect on energy efficiency policies. A high customer charge tends to inhibit energy conservation. Minimizing the customer charge provides the ratepayer with a greater ability to control his/her bill on the basis of usage. For that reason, an excessive customer charge can promote wasteful energy consumption. Pennsylvania's policy favoring energy efficiency, as evidenced by directives requiring utility funded energy conservation programs, provides convincing support for utilizing a basic customer charge benchmark. Public utilities have an incentive to propose fixed charges because the charges produce less financial risk; however, they do not propose to compensate customers for the lower risk through a reduction in the allowable return on equity. Without such explicit compensation to ratepayers, the utilities' frequent argument in favor of the "revenue stability" aspect of fixed charges is not a reasonable policy basis for adopting methods that produce high customer charges.

Q. CAN YOU PROVIDE AN ILLUSTRATION OF THE IMPACT OF CUSTOMER CHARGE METHODS ON ENERGY EFFICIENCY CHOICES?

A. I performed a comparison of the net life cycle savings, as measured by the present value of bill savings net of appliance purchase price, for Energy Star central air conditioning and Energy Star heat pumps, relative to less efficient appliance options.[34] I prepared a comparison of net life cycle savings for purchasing the more efficient appliance based on the OCA customer charge method versus the Companies' proposed customer charge, assuming the Companies' proposed residential revenue requirement. The OCA customer charge produced an 18% higher net life cycle savings ($48) for the more efficient central air condition and an 8% higher net life cycle savings ($185) for the heat pump.[35] Thus, the more limited customer charge benchmark provides an incentive to customers for the purchase of more efficient appliances.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. My primary recommendation is to set the Companies' customer charge at levels consistent with and slightly higher than my benchmark calculation: **ME $6.30; PN $4.90; PP $6.80; WP $5.25.** My recommendation recognizes the energy efficiency policies of the Commonwealth. If the Commission does not find it appropriate to reduce the current level of customer charges, my alternative recommendation is to maintain the current customer charge level for Met-Ed, Penelec, and Penn Power, and raise the West Penn customer charge to $5.25.

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[34] I utilized Energy Star spreadsheets which were developed for the EPA and U.S. Department of Energy.

[35] For simplicity in this illustration, this is an average impact for all four Companies.

V. CLASS DISTRIBUTION OF REVENUE INCREASE

Q. IS THE CLASS COST OF SERVICE STUDY THE ONLY CONSIDERATION IN DISTRIBUTING REVENUE INCREASES AMONG THE CUSTOMER CLASSES?

A. No. The class cost of service study provides useful information for developing the class revenue increases, but it should not be the sole consideration. Non-cost considerations are appropriate in mitigating pure cost of service study results. This principle has been recognized in longstanding regulatory texts, such as Dr. James Bonbright's seminal *Principles of Public Utility Rates*.[36] Although the Companies' CCOSS results are significantly different than OCA's, the Companies' recommendations recognize that movement toward the CCOSS results should be mitigated.[37] Similarly, my position is that rate moderation constraints should be applied to class increases in distribution revenues. My recommendation is based on the Companies' revenue requirement in order to facilitate comparison with the Companies' proposals.

Q. HOW DID YOU DEVELOP CLASS REVENUE INCREASES AT THE COMPANIES' PROPOSED REVENUE REQUIREMENT?

A. Class revenue percent increase proposals are frequently described in terms of a ratio of the class percentage increase relative to the system percentage increase. For classes with very low rates of return based on the OCA CCOSS, a 150% of system average cap was placed on distribution revenue increases. For the other classes with below average rates

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[36] Bonbright, *Principles of Public Utility Rates* at 29, (Columbia Press 1961).

[37] The Companies have implemented an approach of moving classes' share of revenue requirement mid-way between the proportionate responsibility at current and equalized ROR revenues, as determined by the CCOSS.

of return, my recommended class revenue increase percent was set at 135% or 125% of system average. For classes with high rates of return based on the OCA CCOSS, the revenue increase percentage is determined by the remainder of the total increase. Under my CCOSS, the residential class produces significantly above average rates of return, and receives a percent increase below the system average. Within each Company, the same percent increase is applied to all classes with above average rates of return. The percent of system average increase for the residential class is shown below:

OCA Recommendation for RS Class
Percent of Sys Avg. Increase

Met-Ed	0.90
Penelec	0.79
Penn Power	0.87
West Penn	0.82

Q. HAVE YOU PREPARED A SCHEDULE SETTING OUT THE OCA REVENUE DISTRIBUTION RECOMMENDATION BASED ON THE COMPANIES' PROPOSED REVENUE REQUIREMENT?

A. Yes. Schedule CJ-7 sets forth the revenue distribution for each Company by class. OCA proposes a lower rate increase. I recommend a proportionate scale back of the class revenue requirements to match reductions in the overall revenue requirement ultimately adopted by the Commission.

Q. PLEASE SUMMARIZE THE IMPACT OF THE REVENUE INCREASE DISTRIBUTION PROPOSAL.

A. Based on the Company's proposed revenue requirement, the Companies' class revenue increase distribution is compared to my recommendation in the tables below.

(000's)

Met-Ed

Met-Ed	RS	GSV	GSS	GSM	GSL	GP
COMPANY PROPOSED	113,806	244	5,399	14,867	3,231	12,854
Percent Increase	61%	71%	60%	34%	54%	96%
PER OCA	95,862	177	4,623	30,923	5,117	11,441
Percent Increase	52%	52%	52%	71%	86%	86%
	TP	BRD	MS	POL	STLT	TOTAL
COMPANY PROPOSED	1,281	13	298	228	421	152,642
Percent Increase	54%	60%	62%	34%	9%	57%
PER OCA	2,048	11	247	381	1,811	152,642
Percent Increase	86%	52%	52%	57%	39%	57%

Penelec

PN	RS	GSV	GSS	GSM	GSL	GP
COMPANY PROPOSED	87,284	289	6,193	16,151	69	6,470
Percent Increase	45%	44%	59%	26%	1%	53%
PER OCA	59,156	198	5,542	32,277	7,981	6,354
Percent Increase	30%	30%	53%	53%	58%	53%
	LP	BRD	H	POL	STLT	TOTAL
COMPANY PROPOSED	2,452	4	53	784	567	120,316
Percent Increase	29%	16%	6%	29%	13%	39%
PER OCA	4,985	9	426	832	2,556	120,316
Percent Increase	58%	30%	53%	30%	58%	39%

Penn Power

PP	RS	GSR	GSS	GSM	GSL	GP
COMPANY PROPOSED	22,408	22	500	3,654	968	1,655
Percent Increase	39%	45%	14%	32%	37%	103%
PER OCA	18,550	16	1,138	6,352	1,436	891
Percent Increase	33%	33%	33%	56%	56%	56%
	OH	PNP	POL	STLT	GT	TOTAL
COMPANY PROPOSED	(223)	8	82	149	332	29,556
Percent Increase	-53%	12%	30%	14%	26%	37%
PER OCA	233	34	134	351	420	29,556
Percent Increase	56%	49%	49%	33%	33%	37%

West Penn

WP	RS	GS10	GSS	GSM	PP40	GSL	
COMPANY PROPOSED	60,825	137	4,544	3,512	6,147	734	
Percent Increase	30%	28%	40%	6%	90%	4%	
PER OCA	42,014	102	3,902	20,141	1,406	7,070	
Percent Increase	21%	21%	34%	34%	21%	37%	
	POL	PSU	PP44	PP46	AGS	STLT	TOTAL
COMPANY PROPOSED	2,131	401	99	1,921	23	(1,852)	78,623
Percent Increase	54%	37%	355%	80%	161%	-31%	25%
PER OCA	812	223	10	887	5	2,050	78,623
Percent Increase	21%	21%	37%	37%	37%	34%	25%

VI. OTHER RATE DESIGN ISSUES

A. Storm Damage Charge Rider

Q. HAVE THE COMPANIES PROPOSED A STORM DAMAGE RIDER TO RECOVER STORM DAMAGE COSTS BETWEEN BASE RATE CASES?

A. Yes. OCA opposes the implementation of a storm damage rider. OCA witness Alexander addresses the reasons for rejecting the rider.

Q. DO YOU HAVE ANY COMMENTS ON THE CUSTOMER CLASS ALLOCATION USED IN THE STORM RIDER IN THE EVENT THAT THE COMMISSION ALLOWS THE RIDER?

A. Yes. The Companies' proposal applies the same allocation percentage to the storm damage rider as the Companies utilize for storm damage expense in the CCOSS. The CCOSS contains a split of the storm damage cost between customer and demand. Storm damage is most likely to affect overhead lines, poles, and transformers. My CCOSS recommendation is to apply a 100% demand classification for those plant accounts. My preference is to apply the NCP class allocation factors from the CCOSS to the storm damage rider costs. However, at the least, the customer portion of the storm damage rider allocation should be no higher than the overall customer classification percentage for total distribution plant costs in the CCOSS. This would ensure that any classification changes, including modifications to the minimum grid percentages, are reflected in the allocation of rider costs.

B. RT Rate and West Penn's Athletic Field Rates

Q. HAVE THE COMPANIES PROPOSED CONSOLIDATION OF CERTAIN SPECIALIZED RATE CLASSES INTO LARGER GENERIC RATE CLASSES?

A. Yes. The Companies have attempted to simplify the number of rate classes, by consolidating smaller residential and commercial sub-classes into larger classes like RS, small general service, and medium general service. In general, this is a reasonable rate design objective, particularly for unbundled distribution utilities which operate in a competitive retail generation environment. But, despite the reasonable intentions of rate consolidation, the process of eliminating rate classes as "obsolete" can produce surprise and anxiety for the existing customers on those rates. While the rate consolidation effort should be expected to produce occasional above average rate increases for certain customers in the old rate classes, the rate analyst must exercise some degree of judgment in separating tolerable bill increases from excessive rate impacts. The size and sophistication of the customers and their ability to mitigate the impact with changes in usage are also factors to be considered.

Q. HAVE YOU REVIEWED THE BILL IMPACTS OF PARTICULAR RATE CONSOLIDATIONS?

A. Yes. I focused my review on residential rate consolidations and consolidation of certain special rates affecting schools, local governments, and non-profit entities. The Companies' position is that certain appliance end use and time-of-use sub-classes are an artifact of bundled generation service and are less relevant to distribution pricing. As a

general position, this may be true. But non-cost considerations like rate continuity and consumer acceptance of the change are also relevant.

Q. PLEASE DISCUSS THE CONSOLIDATION OF RATE RT (RESIDENTIAL TIME OF USE) INTO THE STANDARD RESIDENTIAL CLASS.

A. Time of use rates require special meters to provide the residential customer with peak and off-peak pricing, and may be accompanied by devices which control the use of certain appliances during peak periods. FirstEnergy views these rates as part of the generation service market, with little value in pricing distribution service. Therefore, a time of use option will be made available for default generation service, but for distribution purposes the RT customers will be placed on the standard distribution rate. In my view, FirstEnergy may be overstating the case for its position that time of use rates have no value in distribution pricing. Congestion can exist on the distribution system, and it is possible that time of use rates could reduce the need for early replacement of distribution equipment that becomes overheated at high-load levels. However, arguably the advantages of simpler standard rate classes outweigh this benefit. Based on my review, the bill impact on existing RT customers is most significant for Metropolitan Edison's rate consolidation.

Q. PLEASE EXPLAIN YOUR POSITION REGARDING THE CONSOLIDATION OF RATE RT INTO RATE RS.

A. My review focused on bill impacts due to consolidation of the RT rate. Both Penelec and Met Ed have RT rates. However, the bill impact for Penelec's RT customers is comparable to, and somewhat less than, the proposed increase for standard residential

customers. Because the impact of the rate consolidation is more significant for Met Ed customers, my recommendation addresses those rates. Met-Ed currently has summer and winter RT rates. The bill impact of the consolidation is particularly significant for the winter RT customers. At the relatively high usage levels which might be associated with electric heating (900 – 2,000 kWh), the total bill impact is 28% - 30%, compared to 16% for existing RS customers.[38] My recommendation is to provide a transitional rate for the Met-Ed Rate RT customers. I recommend consideration of two options. First, the existing RT rate could be grandfathered and revised to produce percentage bill impacts similar to those experienced by existing RS customers. The second option is to grandfather only the non-summer RT customers, with a percent bill increase limited to approximately the same percentage as RS customers. Under either option, the grandfathered rate could be revisited in Met-Ed's next rate case.

Q. PLEASE EXPLAIN YOUR CONCERN REGARDING WEST PENN'S ATHLETIC FIELD RATE.

A. West Penn has a rate for athletic field lighting which is available to schools, non-profit organizations, civic groups and public institutions. According to the Company, this rate was previously grandfathered and the number of customers has subsequently declined. In this case, West Penn proposes to consolidate the existing athletic field rate into commercial Rate 20 and Rate 30. The bill impact is significant for the lower use athletic fields which are placed on Rate 20. For 100 – 1,500 kWh usage, the total bill percentage increase ranges from 41% - 44%. The bill impact for higher use athletic fields placed on

[38] I&E-ME-RS-1-D Att. G.=; I&E-PN-RS-1-D Att. G; I&E-PP-RS-1-D Att. G; I&E-ME-RS-1-D Att. G.

Rate 30 varies considerably, depending on load characteristics. The bill comparisons presented by the Company range from 5% - 50%. My recommendation is to mitigate the bill impacts by grandfathering the minimum bill provision for athletic fields in lieu of the distribution fixed monthly charges applicable to Rate 20 and Rate 30. The proposed Rate 20 and Rate 30 customer charges are $6.79 and $17.95 respectively. My recommendation for a transitional athletic field lighting rate is to collect a minimum bill for recovery of a fixed monthly charge ($6.60) when the level of customer usage is not high enough to produce a monthly bill as much as that amount. In months when the customer's usage charges exceed $6.60, no fixed fee would be charged. The usage rates under Rate 20 and 30, which are higher than the current athletic field rate, would apply to these customers, as proposed by West Penn. In my view, this is a reasonable transitional measure which would not impose a significant impact on other customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, this concludes my direct testimony at this time, but I reserve the right to amend my testimony as necessary.

197158

Schedules
Penelec

Demand-Related Devices Recorded as Conductors and Transformers

FERC ACCOUNT	BOOK COST (Set IV, No. 12)	TOTAL BOOK COST (CCOS.xlsm)	BOOK COST % OF TOTAL BOOK COST
MetEd			
36500	$22,496,597	$499,933,000	4.499922
36700	$4,727,905	$203,212,000	2.326588
36800	$23,740,979	$395,172,576	6.007750
PennElec			
36500	$27,535,963	$940,123,027	2.928974
36700	$4,727,905	$149,414,804	3.164281
36800	$11,291,946	$362,159,280	3.117950
PennPower			
36500	$6,367,869	$135,319,000	4.705820
36700	$4,727,905	$55,362,000	8.539982
36800	$4,614,799	$98,864,887	4.667783
WestPenn			
36500	$16,676,872	$420,368,000	3.967208
36700	$4,727,905	$127,487,000	3.708539
36800	$17,453,685	$361,321,422	4.830515

Customer Percentages Adjusted for Demand-Related Devices

FERC ACCOUNT	METROPOLITAN EDISON	PENNSYLVANIA ELECTRIC	PENNSYLVANIA POWER	WEST PENN POWER
364: Poles, Towers & Fixtures	78.0%	79.0%	84.5%	85.6%
365: Overhead Conductors & Devices	79.6%	82.7%	86.4%	89.1%
367: Underground Conductors & Devices	86.1%	76.5%	73.8%	81.9%
368: Line Transformers	50.7%	65.1%	61.9%	72.3%

Page One

Minimum Grid Component Based On Labor Installation Expense

FERC ACCOUNT	ME	PN	PP	WP
FERC 364: Poles, Towers & Fixtures				
Labor Only Min. Plt.	**54.4%**	**54.4%**	**54.4%**	**54.4%**
Adjusted Customer %	**42.4%**	**48.1%**	**46.0%**	**46.6%**
FERC 365: Overhead Conductors & Devices				
Labor Only Min. Plt.	**66.7%**	**66.7%**	**66.7%**	**66.7%**
Adjusted Customer %	**56.1%**	**57.1%**	**60.8%**	**62.1%**
FERC 367: Underground Conductors & Devices				
Labor Only Min. Plt.	**16.0%**	**16.0%**	**16.0%**	**16.0%**
Adjusted Customer %	**14.1%**	**12.8%**	**13.2%**	**13.7%**
FERC 368: Line Transformers				
Labor Only Min. Plt.	**26.3%**	**26.3%**	**26.3%**	**26.3%**
Adjusted Customer %	**14.9%**	**17.9%**	**17.5%**	**20.3%**

Source:
Response to OCA Interrogatory Set IV, No. 1 (Question 1(e)).

Page Two

Minimum Grid Component Based On Labor Installation Expense

(Excludes Adjustment for Demand-Related Devices-Schedule CJ-1)

FERC ACCOUNT	ME	PN	PP	WP
FERC 364: Poles, Towers & Fixtures				
Labor Only Min. Plt.	54.4%	54.4%	54.4%	54.4%
Customer % Excluding Devices	42.4%	43.0%	46.0%	46.6%
FERC 365: Overhead Conductors & Devices				
Labor Only Min. Plt.	66.7%	66.7%	66.7%	66.7%
Customer % Excluding Devices	53.1%	55.1%	57.6%	59.5%
FERC 367: Underground Conductors & Devices				
Labor Only Min. Plt.	16.0%	16.0%	16.0%	16.0%
Customer % Excluding Devices	13.8%	12.2%	11.8%	13.1%
FERC 368: Line Transformers				
Labor Only Min. Plt.	26.3%	26.3%	26.3%	26.3%
Customer % Excluding Devices	13.3%	17.1%	16.3%	19.0%

Sources:
Response to OCA Interrogatory ME Set IV, No. 1 (Question 1(e)).
Minimum Plant Based on Labor Percent and Schedule CJ-1 Adjustment.

PENNSYLVANIA ELECTRIC COMPANY
COST OF SERVICE STUDY - TOTAL SUMMARY
FULLY FUTURE TEST YEAR
NO MINIMUM SYSTEM
PRESENT RATES, $1,000s

PENELEC CCOS WITHOUT MINIMUM GRID

	TOTAL RETAIL	NY JURIS	PA JURIS	RT	RS	GSV	GSS	GSM	GSL	GP	LP	BRD	H	POL	STLT
RATE BASE															
Plant in Service	2,648,144	15,985	2,632,159	-	1,225,331	5,261	88,410	724,085	252,622	110,773	118,322	186	10,501	38,218	58,451
Depreciation Reserve	870,433	5,157	865,276	-	408,679	1,679	29,935	228,671	79,464	34,382	36,786	59	3,305	24,959	17,358
Net Plant	1,777,711	10,828	1,766,884	-	816,651	3,582	58,475	495,414	173,158	76,391	81,536	128	7,196	13,259	41,093
Rate Base Additions	210,019	106	209,913	-	97,730	425	7,029	58,607	20,488	8,932	9,551	15	851	2,436	3,849
Rate Base Deductions	439,056	2,573	436,483	-	202,979	870	14,989	122,112	40,924	18,483	18,990	30	1,686	6,164	9,255
Rate Base Other Total	(229,037)	(2,468)	(226,569)	-	(105,249)	(445)	(7,960)	(63,506)	(20,437)	(9,551)	(9,439)	(15)	(835)	(3,728)	(5,406)
Rate Base Total	1,548,674	8,360	1,540,314	-	711,402	3,137	50,515	431,908	152,722	66,841	72,097	113	6,361	9,532	35,688
INCOME STATEMENT															
Revenue															
Tariff Revenue Total	312,248	1,775	310,473	-	195,510	655	10,553	61,462	13,677	12,099	8,543	29	812	2,751	4,381
Other Revenue Total	12,121	49	12,072	-	7,505	18	385	1,686	554	249	266	1	24	1,318	66
Retail Total	324,368	1,824	322,544	-	203,014	673	10,938	63,149	14,231	12,348	8,809	30	836	4,069	4,447
Expenses															
Total Operation & Mai	105,934	553	105,380	-	63,528	165	4,883	18,966	5,896	3,918	4,060	5	255	410	3,295
Depreciation Expense	84,402	497	83,904	-	42,357	169	3,728	21,042	6,802	3,030	3,006	6	297	1,231	2,236
Other Expenses Amor	4,525	-	4,525	-	1,777	10	101	1,437	519	224	242	0	21	75	118
Taxes Other than Inco	6,683	39	6,644	-	3,513	12	284	1,454	478	288	303	0	20	44	246
Gross Receipts Tax	18,318	-	18,318	-	11,535	39	623	3,626	807	714	504	2	48	162	258
Total Operating Expen	219,861	1,090	218,771	-	122,711	394	9,619	46,525	14,502	8,174	8,115	14	641	1,922	6,153
Income Before Taxes	104,507	734	103,773	-	80,304	279	1,318	16,624	(271)	4,175	693	16	195	2,147	(1,706)
Income taxes															
Current State Income	9,664	-	9,582	-	7,934	25	147	1,188	(216)	384	29	1	12	207	(131)
Current Federal Incom	30,476	289	30,216	-	25,021	80	463	3,747	(680)	1,210	90	5	38	653	(412)
Provision for Deferred	2,597	16	2,581	-	1,202	5	87	710	248	109	116	0	10	37	57
Investent Tax Credit A	(302)	(2)	(300)	-	(139)	(1)	(10)	(83)	(29)	(13)	(14)	(0)	(1)	(4)	(7)
Total Income Tax	42,434	302	42,078	-	34,018	110	687	5,563	(677)	1,689	221	6	59	894	(492)
Net Income After Tax	62,072	431	61,695	-	46,285	169	631	11,061	406	2,486	472	10	136	1,253	(1,215)
Rate of Return	**4.01%**	**5.16%**	**4.01%**		**6.51%**	**5.38%**	**1.25%**	**2.56%**	**0.27%**	**3.72%**	**0.65%**	**8.64%**	**2.14%**	**13.15%**	**-3.40%**
ROR with Minimum S	**4.01%**	**5.15%**	**4.01%**		**3.08%**	**10.77%**	**-1.53%**	**13.63%**	**11.93%**	**1.02%**	**4.96%**	**20.69%**	**15.87%**	**11.35%**	**-3.80%**

COST OF SERVICE STUDY - TOTAL SUMMARY
FULLY FUTURE TEST YEAR
PENNSYLVANIA ELECTRIC
PRESENT RATES, $1,000s

PENELEC CCOS-ALTERNATIVE

ADJUSTED FOR NO LOAD COMPONENT AND DEMAND-RELATED DEVICES

Adjusted Customer Cl	TOTAL RETAIL	NY JURIS	PA JURIS	RT	RS	GSV	GSS	GSM	GSL	GP	LP	BRD	H	POL	STLT
RATE BASE															
Plant in Service	2,648,144	15,992	2,632,152	-	1,500,354	4,332	131,745	503,732	161,875	139,918	89,105	141	6,926	39,121	54,903
Depreciation Reserve	870,433	5,150	865,283	-	479,922	1,430	41,247	170,173	55,410	41,118	29,907	47	2,357	25,190	18,482
Net Plant	1,777,711	10,842	1,766,869	-	1,020,432	2,902	90,497	333,560	106,465	98,800	59,198	94	4,569	13,931	36,420
Rate Base Additions	210,019	106	209,913	-	120,024	349	10,542	40,747	13,133	11,290	7,189	11	561	2,508	3,560
Rate Base Deductions	439,056	2,574	436,482	-	247,053	721	21,934	86,800	26,382	23,144	14,318	23	1,113	6,308	8,686
Rate Base Other Total	(229,037)	(2,469)	(226,568)	-	(127,030)	(372)	(11,392)	(46,052)	(13,249)	(11,854)	(7,129)	(11)	(552)	(3,801)	(5,127)
Rate Base Total	1,548,674	8,373	1,540,301	-	893,402	2,530	79,105	287,507	93,216	86,947	52,069	83	4,018	10,130	31,294
INCOME STATEMENT															
Revenue															
Tariff Revenue Total	312,248	1,775	310,473	-	195,510	655	10,553	61,462	13,677	12,099	8,543	29	812	2,751	4,381
Other Revenue Total	12,121	49	12,072	-	8,108	16	480	1,203	354	314	201	1	17	1,320	59
Retail Total	324,368	1,824	322,544	-	203,618	671	11,033	62,665	14,032	12,413	8,744	29	829	4,071	4,440
Expenses															
Total Operation & Mair	105,934	554	105,380	-	70,461	141	5,976	13,410	3,609	4,792	3,183	4	165	433	3,206
Depreciation Expense	84,402	497	83,904	-	49,224	145	4,814	15,477	4,511	3,745	2,284	5	207	1,254	2,238
Other Expenses Amor	4,525	-	4,525	-	2,345	8	191	983	331	284	182	0	14	77	111
Taxes Other than Inco	6,683	39	6,644	-	4,061	10	371	1,015	298	354	237	0	13	46	239
Gross Receipts Tax	18,318	-	18,318	-	11,535	39	623	3,626	807	714	504	2	48	162	258
Total Operating Expen	219,861	1,090	218,771	-	137,626	344	11,974	34,511	9,556	9,890	6,390	11	447	1,971	6,052
Income Before Taxes	104,507	733	103,773	-	65,992	328	(941)	28,154	4,475	2,524	2,354	18	382	2,100	(1,612)
Income taxes															
Current State Income	9,664	-	9,582	-	6,271	31	(115)	2,523	334	196	217	2	34	202	(112)
Current Federal Incom	30,476	288	30,216	-	19,775	98	(364)	7,958	1,054	619	683	5	106	636	(354)
Provision for Deferred	2,597	16	2,581	-	1,471	4	129	494	159	137	87	0	7	38	54
Investent Tax Credit A	(302)	(2)	(300)	-	(170)	(0)	(15)	(58)	(19)	(16)	(10)	(0)	(1)	(5)	(6)
Total Income Tax	42,434	302	42,079	-	27,346	133	(365)	10,917	1,528	936	977	7	146	872	(419)
Net Income After Tax	62,072	431	61,695	-	38,645	195	(576)	17,236	2,947	1,587	1,377	11	237	1,228	(1,194)
Rate of Return	**4.01%**	**5.15%**	**4.01%**		**4.33%**	**7.70%**	**-0.73%**	**6.00%**	**3.16%**	**1.83%**	**2.65%**	**13.16%**	**5.89%**	**12.12%**	**-3.81%**
ROR Per Company	4.01%	5.15%	4.01%		3.08%	10.77%	-1.53%	13.63%	11.93%	1.02%	4.96%	20.69%	15.87%	11.35%	-3.80%

PENNSYLVANIA ELECTRIC COMPANY
COST OF SERVICE STUDY - TOTAL SUMMARY
FULLY FUTURE TEST YEAR
OCA Version
PRESENT RATES, $1,000s

OCA CCOS Study: Penelec at Present Rates

	PA JURIS	RS	GSV	GSS	GSM	GSL	GP	LP	BRD	H	POL	STLT
RATE BASE												
Plant in Service	2,632,159	1,220,497	5,283	88,451	726,827	253,286	111,360	118,738	186	10,539	38,334	58,657
Depreciation Reserve	865,275	405,733	1,692	29,960	230,342	79,869	34,740	37,040	59	3,328	25,029	17,484
Net Plant	1,766,883	814,764	3,591	58,491	496,484	173,417	76,621	81,699	128	7,211	13,305	41,174
Rate Base Additions	209,913	97,730	425	7,029	58,607	20,488	8,932	9,551	15	851	2,436	3,849
Rate Base Deductions	436,483	202,979	870	14,989	122,112	40,924	18,483	18,990	30	1,686	6,164	9,255
Rate Base Other Total	(226,569)	(105,249)	(445)	(7,960)	(63,506)	(20,437)	(9,551)	(9,439)	(15)	(835)	(3,728)	(5,406)
Rate Base Total	1,540,314	709,515	3,146	50,531	432,979	152,981	67,070	72,260	113	6,376	9,577	35,768
INCOME STATEMENT												
Revenue												
Tariff Revenue Total	310,473	195,510	655	10,553	61,462	13,677	12,099	8,543	29	812	2,751	4,381
Other Revenue Total	12,072	6,662	19	557	2,103	634	320	316	1	29	1,340	91
Retail Total	322,544	202,172	674	11,111	63,565	14,311	12,420	8,858	30	841	4,091	4,472
Expenses												
Total Operation & Maintenance Expense	105,380	55,403	200	5,072	23,530	6,987	4,882	4,744	5	318	605	3,633
Depreciation Expense	83,904	41,710	172	3,733	21,409	6,891	3,108	3,062	6	302	1,247	2,263
Other Expenses Amortization Expense Total	4,525	1,777	10	101	1,437	519	224	242	0	21	75	118
Taxes Other than Income Taxes Excl GRT	6,644	3,404	12	306	1,508	489	297	310	0	21	47	249
Gross Receipts Tax	18,318	11,535	39	623	3,626	807	714	504	2	48	162	258
Total Operating Expense	218,771	113,829	433	9,835	51,510	15,693	9,226	8,862	14	710	2,136	6,523
Income Before Taxes	103,774	88,342	242	1,275	12,055	(1,382)	3,193	(3)	16	131	1,955	(2,050)
Income taxes												
Current State Income Tax	9,582	8,677	22	156	762	(321)	290	(38)	1	6	190	(163)
Current Federal Income Tax	30,216	27,362	69	493	2,402	(1,012)	916	(118)	5	19	598	(515)
Provision for Deferred Income Taxes	2,581	1,197	5	87	713	248	109	116	0	10	38	58
Investent Tax Credit Adjustments	(300)	(139)	(1)	(10)	(83)	(29)	(13)	(14)	(0)	(1)	(4)	(7)
Total Income Tax	42,079	37,096	95	725	3,793	(1,114)	1,303	(53)	6	34	821	(627)
Net Income After Tax	61,695	51,246	147	550	8,262	(268)	1,890	50	10	97	1,134	(1,423)
Rate of Return	4.01%	7.22%	4.66%	1.09%	1.91%	-0.17%	2.82%	0.07%	8.64%	1.53%	11.84%	-3.98%
Relative Rate of Return		**180.3%**	**116.4%**	**27.2%**	**47.6%**	**-4.4%**	**70.4%**	**1.7%**	**215.7%**	**38.1%**	**295.7%**	**-99.4%**
ROR Per Company CCOS	4.01%	3.08%	10.77%	-1.53%	13.63%	11.93%	1.02%	4.96%	20.69%	15.87%	11.35%	-3.80%
RROR Per Company CCOS		76.9%	268.9%	-38.1%	340.3%	297.9%	25.6%	123.7%	516.6%	396.2%	283.3%	-94.9%

PENNSYLVANIA ELECTRIC COMPANY
COST OF SERVICE STUDY - TOTAL SUMMARY
FULLY FUTURE TEST YEAR
OCA Version
EQUAL RATES, $1,000s

OCA CCOS at Equalized ROR: Penelec

	PA JURIS	RS	GSV	GSS	GSM	GSL	GP	LP	BRD	H	POL	STLT
RATE BASE												
Plant in Service	2,632,159	1,220,497	5,283	88,451	726,827	253,286	111,360	118,738	186	10,539	38,334	58,657
Depreciation Reserve	865,275	405,733	1,692	29,960	230,342	79,869	34,740	37,040	59	3,328	25,029	17,484
Net Plant	1,766,883	814,764	3,591	58,491	496,484	173,417	76,621	81,699	128	7,211	13,305	41,174
Rate Base Additions	209,913	97,730	425	7,029	58,607	20,488	8,932	9,551	15	851	2,436	3,849
Rate Base Deductions	436,483	202,979	870	14,989	122,112	40,924	18,483	18,990	30	1,686	6,164	9,255
Rate Base Other Total	(226,569)	(105,249)	(445)	(7,960)	(63,506)	(20,437)	(9,551)	(9,439)	(15)	(835)	(3,728)	(5,406)
Rate Base Total	1,540,314	709,515	3,146	50,531	432,979	152,981	67,070	72,260	113	6,376	9,577	35,768
INCOME STATEMENT												
Revenue												
Tariff Revenue Total	430,790	209,467	863	17,178	111,777	37,243	18,784	19,353	28	1,597	2,136	12,363
Other Revenue Total	12,072	6,662	19	557	2,103	634	320	316	1	29	1,340	91
Retail Total	442,861	216,129	882	17,735	113,880	37,877	19,104	19,669	29	1,626	3,476	12,454
Expenses												
Total Operation & Maintenance Expense	105,380	55,403	200	5,072	23,530	6,987	4,882	4,744	5	318	605	3,633
Depreciation Expense	83,904	41,710	172	3,733	21,409	6,891	3,108	3,062	6	302	1,247	2,263
Other Expenses Amortization Expense Total	4,525	1,777	10	101	1,437	519	224	242	0	21	75	118
Taxes Other than Income Taxes Excl GRT	6,644	3,404	12	306	1,508	489	297	310	0	21	47	249
Gross Receipts Tax	25,417	12,359	51	1,013	6,595	2,197	1,108	1,142	2	94	126	729
Total Operating Expense	225,869	114,653	445	10,226	54,479	17,083	9,621	9,499	13	757	2,100	6,993
Income Before Taxes	216,992	101,476	438	7,509	59,401	20,794	9,484	10,170	15	870	1,376	5,460
Income taxes												
Current State Income Tax	20,892	9,989	41	779	5,491	1,894	919	979	1	80	132	587
Current Federal Income Tax	65,884	31,499	130	2,456	17,317	5,974	2,898	3,086	4	251	416	1,851
Provision for Deferred Income Taxes	2,581	1,197	5	87	713	248	109	116	0	10	38	58
Investent Tax Credit Adjustments	(300)	(139)	(1)	(10)	(83)	(29)	(13)	(14)	(0)	(1)	(4)	(7)
Total Income Tax	89,057	42,546	176	3,312	23,438	8,087	3,913	4,168	6	340	580	2,489
Net Income After Tax	127,935	58,930	261	4,197	35,962	12,706	5,571	6,002	9	530	795	2,971
Rate of Return	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%
Revs Per Company CCOS	442,861	303,606	579	29,591	46,370	11,061	25,648	11,089	16	545	3,485	10,870
Difference	**(0)**	**87,477**	**(303)**	**11,856**	**(67,510)**	**(26,816)**	**6,544**	**(8,580)**	**(13)**	**(1,081)**	**9**	**(1,584)**

Penelec Customer Charge Analysis

Rate Base/Return

Meters	7,873
Services	100,409
Meter Accum. Dep.	(546)
Services Acc. Dep.	50,056
Customer Deposits	9,403
Customer Advances	19
Deferred Taxes	-
Rate Base	49,350
Return and Taxes	5,219
Expenses	
Meter Operation	441
Meter Maintenance	1,019
Customer Accounts	**12,905**
Exclude Uncollect.	2,707
Meter Depreciation	525
Services Deprec.	2,052
Accel. Depreciation	7,487
Smart Meter Amort.	178
Billing-Call Center	727
Total Expenses	22,627
Total Cost	27,846
Billing Units	5,754,996
customer charge	$ 4.84

Debt ratio	50.10%
Equity ratio	49.90%
Debt cost:	5.21%
Equity cost:	9.34%
Weighted average cost after tax	6.19%
Weighted average cost before tax	7.27%
Composite Tax Rate	0.414935
Tax Multiplier	0.709212

(000'S)

COMPARISON OF CLASS REVENUE DISTRIBUTION PROPOSALS (RATE SCHEDULE)

METROPOLITAN EDISON COMPANY	RS	GSV	GSS	GSM	GSL	GP	TP	BRD	MS	POL	STLT	TOTAL
Current Tariff Revenues*	186,054	344	8,972	43,400	5,985	13,382	2,395	22	479	668	4,644	266,346
Company Proposed Tariff Revenues^	299,860	589	14,371	58,268	9,216	26,236	3,676	35	777	896	5,065	418,988
Company Proposed Increase	113,806	244	5,399	14,867	3,231	12,854	1,281	13	298	228	421	152,642
Percentage Increase	61.17	70.87	60.18	34.26	53.98	96.06	53.51	59.74	62.18	34.05	9.06	57.31
Ratio of Class Percent Increase to System Increase	106.73	123.66	105.00	59.77	94.19	167.61	93.37	104.24	108.49	59.42	15.82	100.00
Increase-OCA Rev Spread	95862	177	4623	30923	5117	11441	2048	11	247	381	1811	152,642
Percentage Increase	52%	52%	52%	71%	86%	86%	86%	52%	52%	57%	39%	57.3%
Ratio of Class Percent Increase to System Increase	89.92%	89.92%	89.92%	124.35%	149.21%	149.21%	149.21%	89.92%	89.92%	99.48%	68.06%	100.00%

PENNSYLVANIA ELECTRIC COMPANY	RS	GSV	GSS	GSM	GSL	GP	LP	BRD	H	POL	STLT	TOTAL
Current Tariff Revenues*	195,510	655	10,553	61,462	13,677	12,099	8,543	29	812	2,751	4,381	310,473
Company Proposed Tariff Revenues^	282,793	944	16,746	77,614	13,746	18,569	10,994	33	865	3,535	4,948	430,788
Company Proposed Increase	87,284	289	6,193	16,151	69	6,470	2,452	4	53	784	567	120,316
Percentage Increase	44.64	44.12	58.68	26.28	0.50	53.48	28.70	15.54	6.48	28.50	12.94	38.75
Ratio of Class Percent Increase to System Increase	115.20	113.86	151.42	67.81	1.29	137.99	74.07	40.11	16.73	73.55	33.40	100.00
Increase-OCA Rev Spread	59156	198	5542	32277	7981	6354	4985	9	426	832	2556	120316
Percentage Increase	30.3%	30.3%	52.5%	52.5%	58.4%	52.5%	58.4%	30.3%	52.5%	30.3%	58.4%	38.8%
Ratio of Class Percent Increase to System Increase	78.08%	78.08%	135.51%	135.51%	150.57%	135.51%	150.57%	78.08%	135.51%	78.08%	150.57%	100.00%

PENNSYLVANIA POWER COMPANY	RS	GSR	GSS	GSM	GSL	GP	OH	PNP	POL	STLT	GT	TOTAL
Current Tariff Revenues*	56,756	49	3,483	11,445	2,588	1,605	420	69	274	1,073	1,286	79,049
Company Proposed Tariff Revenues^	79,164	72	3,983	15,099	3,556	3,260	197	77	356	1,223	1,618	108,605
Company Proposed Increase	22,408	22	500	3,654	968	1,655	-223	8	82	149	332	29,556
Percentage Increase	39.48	44.63	14.37	31.93	37.40	103.13	-53.15	12.18	30.01	13.91	25.82	37.39
Ratio of Class Percent Increase to System Increase	105.59	119.36	38.42	85.39	100.02	275.82	-142.14	32.57	80.26	37.21	69.05	100.00
Increase-OCA Rev Spread	18550	16	1138	6352	1436	891	233	33.82	134.19	351	420	29,556
Percentage Increase	32.7%	32.7%	32.7%	55.5%	55.5%	55.5%	55.5%	49.0%	49.0%	32.7%	32.7%	37.4%
Ratio of Class Percent Increase to System Increase	87.41%	87.41%	87.41%	148.44%	148.44%	148.44%	148.44%	131.05%	131.05%	87.41%	87.41%	100.00%

WEST PENNSYLVANIA POWER COMPANY	RS	GS10	GSS	GSM	PP40	GSL	POL	PSU	PP44	PP46	AGS	STLT	TOTAL
Current Tariff Revenues*	204,009	494	11,475	59,237	6,829	19,107	3,945	1,084	28	2,399	15	6,031	314,652
Company Proposed Tariff Revenues^	264,834	631	16,019	62,749	12,976	19,841	6,076	1,485	127	4,320	38	4,179	393,274
Company Proposed Increase	60,825	137	4,544	3,512	6,147	734	2,131	401	99	1,921	23	-1,852	78,623
Percentage Increase	29.81	27.70	39.60	5.93	90.02	3.84	54.01	37.05	355.05	80.11	160.74	-30.70	24.99
Ratio of Class Percent Increase to System Increase	119.32	110.87	158.48	23.72	360.27	15.36	216.16	148.28	1420.92	320.61	643.28	-122.88	100.00
Increase-OCA Rev Spread	42014	102	3902	20141	1406	7070	812	223	10	887	5	2050	78,623
Percentage Increase	20.6%	20.6%	34.0%	34.0%	20.6%	37.0%	20.6%	20.6%	37.0%	37.0%	37.0%	34.0%	25.0%
Ratio of Class Percent Increase to System Increase	82.42%	82.42%	136.07%	136.07%	82.42%	148.08%	82.42%	82.42%	148.08%	148.08%	148.08%	136.07%	100.00%

Appendix A: Johnson Vitae and Professional Experience

SUMMARY OF QUALIFICATIONS

CLARENCE JOHNSON

EDUCATION

Bachelor of Science, Political Science, University of Houston.

Master of Arts, College of Social Science (Interdisciplinary/Urban Studies), University of Houston.

EXPERIENCE

Mr. Johnson has more than 25 years experience as an expert witness and analyst related to electric and telecommunications utility issues.

CURRENT EMPLOYMENT

Mr. Johnson currently provides professional consulting and analytical analyses regarding regulatory and public policies related to public utilities and the energy industry.

PREVIOUS EMPLOYMENT 1983-2008

From September 1983 to June 2008, Mr. Johnson was a Regulatory Analyst for the Office of Public Utility Counsel. He was the professional staff person with primary responsibility for advising the Public Counsel on economic and regulatory policy issues. His responsibilities included: presenting expert testimony on regulatory matters; research related to rate filings of regulated public utilities; acting as a non-testifying expert and advising attorneys in cross-examination of witnesses and development of trial exhibits for utility regulatory proceedings; analyzing policies and practices for regulating public utilities; and preparing comments on proposed Public Utility Commission rules; assisting financial and economic staff in the development and preparation of testimony; providing expert testimony on selected issues; preparation of reports to the Legislature regarding the utility regulatory process.

EMPLOYMENT BEFORE 1983

During the period 1977 to 1983, Mr. Johnson extensively engaged in analysis and supervision of public interest advocacy programs. He directed two non-profit corporations involved in public policy research from 1978 to 1980 and 1982 to 1983, respectively; responsibilities included overall management of the corporations, negotiation and management of grants and contracts, supervision of research activities, and presentations of research findings to legislative and administrative governmental entities. From 1980 to 1982, he also performed policy analysis and substantive research on the impact of governmental policies for two publicly-funded entities. His responsibilities for the statewide support center for legal services programs in Texas assessed the effect of federal and state regulatory changes upon indigent clients. As an analyst for the Texas State Senate's Natural Resources

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

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

MEMBERSHIP American Economics Association.

TESTIMONY ON BEHALF OF TEXAS OFFICE OF PUBLIC UTILITY COUNSEL

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Docket No. 11892,	General Counsel's Original Petition for Generic Proceeding Regarding Purchased Power,
Subject:	Impact of Purchased Power on Cost of Capital.
Docket No. 12700,	El Paso Electric Company,
Subject:	Acquisition, Revenue Requirement and Rate Design.
Docket No. 12957,	Houston Lighting & Power Company,
Subject:	Contract Pricing Tariff.
Docket No. 13100,	Texas Utilities Electric Company,
Subject:	Competitive Pricing Tariffs.
Docket No. 13575,	Texas Utilities Electric Company,
Subject:	Demand Side Management and Purchase Power Recovery.
Docket No. 12065,	Houston Lighting & Power Company,
Subject:	Revenue Requirement/Plant Cancellation/Prudence.
Docket No. 12065,	Houston Lighting & Power Company,
Subject:	Cost Allocation and Rate Design.
Docket No. 13943,	Gulf Coast Power Connect,
Subject:	Transmission Line CCN.
Docket No. 13575,	TUEC Application for Relief Regarding Recovery Solicitations,
Subject:	DSM and Purchase Power Cost Recovery.
Docket No. 13369,	West Texas Utilities Company,
Subject:	Cost Allocation and Rate Design.
Docket No. 14435,	Southwestern Electric Power Co.,
Subject:	Rate Design.
Docket No. 14716,	Texas Utilities Electric Company,
Subject:	Wholesale Competitive Rate.
Docket No. 14965,	Central Power and Light Company,
Subject:	Cost Allocation, Rate Design and Competitive Issues.

Docket No. 14965,	Central Power and Light Company,
Subject:	Reply, Cost Allocation, Rate Design and Competitive Issues.
Docket No. 15560,	Texas-New Mexico Power Company,
Subject:	Competitive Issues.
Docket No. 16705,	Entergy Gulf States, Inc.,
Subject:	Cost Allocation, Rate Design and Competitive Issues.
Docket No. 16705,	Entergy Gulf States, Inc.,
Subject:	Reply, Cost Allocation, Rate Design and Competitive Issues.
Docket No. 16995,	Central Southwest Corp.,
Subject:	Integrated Resource Planning.
Docket No. 17751,	Texas-New Mexico Power Company,
Subject:	Rate Design and Competitive Issues.
Docket No. 18845,	CPL, WTU, and SWEPCO,
Subject:	Integrated Resource Planning.
Docket No. 21527,	TXU Financing Order,
Subject:	Cost Allocation.
Docket No. 21528,	CPL Financing Order,
Subject:	Cost Allocation.
Docket No. 21591,	Sharyland Utilities Initial Rates & Tariffs,
Subject:	Deferrals.
Docket No. 21956,	Reliant Business Separation Plan,
Subject:	Price to Beat and Capacity Auction.
Docket No. 22344,	Generic Rate Design and Customer Classification for TDUs,
Subject:	Rate Design.
Docket No. 22349,	TNMP Unbundling,
Subject:	Competitive Transition Charge and Revenue Requirements/Cost Allocation/Rate Design.

Docket No. 22350,	TXU Unbundling,
Subject:	Competitive Transition Charge.
Docket No. 22351,	Southwestern Public Service Company Unbundling,
Subject:	Cost Allocation/Rate Design.
Docket No. 22352,	Central Power & Light Company,
Subject:	Competitive Transition Charge.
Docket No. 22355,	Reliant Unbundling,
Subject:	Non-Bypassable Charges and Competitive Transition Charge/Cost Allocation/Rate Design.
Docket No.22356,	Entergy Gulf States Utilities Unbundling,
Subject:	Revenue Requirements/Cost Allocation/Competitive Transition Charge/Settlement Rate Design.
Docket No. 24194,	Application of TNMP to Establish Price to Beat Fuel Factor,
Subject:	Fuel and purchased power costs.
Docket No. 25230,	Joint Application for Approval of Stipulation Regarding TXU Electric Company Transition to Competition Issues,
Subject:	Retail Clawback Provisions of Non-Unanimous Agreement.
Docket No. 25314,	Application of West Texas Utilities Company and Mutual Energy WTU to Establish a Fuel Reconciliation Methodology for Southwest Power Pool (SPP) Customers,
Subject:	Fuel Cost Method.
Docket No. 24336,	Application of Entergy Gulf States, Inc. for Approval of Price to Beat Factor,
Subject:	Unaccounted for Energy.
Docket No. 23320,	Petition of ERCOT for Approval of the ERCOT Administrative Fee,
Subject:	ERCOT Fee Structure.
Docket No. 26194,	El Paso Electric Company Fuel Reconciliation,
Subject:	Purchased Power and Off-System Sales.

Docket No. 27576,	Application of Texas-New Mexico Power Company for Reconciliation of Fuel Costs,
Subject:	Fuel Reconciliation.
Docket No. 28813,	Inquiry Into Rates of Cap Rock Energy,
Subject:	Revenue Requirements/Cost Allocation/Rate Design.
Docket No. 28840,	Application of AEP Texas Central Company for Change in Rates,
Subject:	Cost Allocation/Rate Design/Affiliate Transactions.
Docket No. 30485,	Application of CenterPoint Energy Houston Electric, LLC For A Financing Order,
Subject:	Transition Charge Recovery.
Docket No. 30143,	Petition of El Paso Electric Company to Reconcile Fuel Costs (Initial and Rebuttal Testimonies),
Subject:	Fuel Reconciliation.
Docket No. 30706,	Application of CenterPoint Energy Houston Electric, LLC for A Competition Transition Charge,
Subject:	Competitive Transition Charge Structure.
Docket No. 31315,	Application of Entergy Gulf States, Inc. for Approval of Incremental Purchased Capacity Recovery Rider,
Subject:	Purchase Power Capacity Rates.
Docket No. 31544,	Application of Entergy Gulf States, Inc. for Recovery of Transition to Competition Costs,
Subject:	Allocation of Transition Costs.
Docket No. 31994,	Application of Texas-New Mexico Power Company's to Establish a Competition Transition Charge Pursuant to P.U.C. Subst. R. 25.263(N),
Subject:	Competition Transition Charge.
Docket No. 32475,	Application of AEP Texas Central Company for a Financing Order,
Subject:	Securitization of Stranded Costs.

Docket No. 32758,	Application of AEP Texas Central Company for a Competition Transition Charge Pursuant to P.U.C. Subst. R. 25.263(n),
Subject:	Competitive Transition Charge.
Docket No. 32795,	Staff's Petition to Initiate Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA § 39.253(f),
Subject:	Stranded Costs Allocation.
Docket No. 32907,	Application of Entergy Gulf States, Inc. for Determination of Hurricane Reconstruction Costs,
Subject:	Cost Allocation.
Docket No. 32766,	Application of Southwestern Public Service Company for: (1) Authority to Change Rates; (2) Reconciliation of its Fuel Costs for 2004 and 2005; (3) Authority to Revise the Semi-Annual Formulae Originally Approved in Docket No. 27751 Used to Adjust its Fuel Factors; and (4) Related Relief,
Subject:	Cost Allocation/Rate Design.
Docket No. 33586,	Application of Entergy Gulf States, Inc. for a Financing Order,
Subject:	Financing Order Allocation.
Docket No. 32710,	Application of Entergy Gulf States, Inc. for Authority to Reconcile Fuel and Purchased Power Costs,
Subject:	Capacity Rider Allocation.
Docket No. 31461,	Application of AEP Texas North Company for a Competition Transition Charge Under to Subst. R. §25.263(N),
Subject:	Competition Transition Charge.
Docket No. 32795,	Staff's Petition to Initiate a Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA § 39.253(f),
Subject:	Stranded Cost Allocation.
Docket No. 33309,	Application of AEP Texas Central Company for Authority to Change Rates,
Subject:	Rate Design and Energy Efficiency Costs.

Docket No. 33310,	Application of AEP Texas North Company for Authority to Change Rates,
Subject	Energy Efficiency Costs and Riders.
Docket No. 32902,	CenterPoint Energy Houston Electric, LLC Compliance Tariff,
Subject:	Allocation of Stranded Costs.
Docket No. 34077,	Joint Report and Application of Oncor and EFH Pursuant to § 14.101,
Subject:	Leveraged buyout of utility.
Docket No. 35105,	Compliance Tariff Filing of AEP Texas,
Subject:	Allocation of Stranded Costs.
Docket No. 35038,	Texas-New Mexico Power Company Tariff Filing in Compliance with the Final Order in Docket No. 33106,
Subject:	Allocation of Stranded Costs.
Docket No. 34800,	Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs,
Subject:	Cost Allocation & Rate Design.
*Docket No. 37482,	Application of Entergy Texas for a PCRF,
Subject:	Purchase Power.
*Docket No. 37744,	Application of Entergy Texas, Inc. for Authority to Change Rates,
Subject:	Cost allocation, rate design, proposed riders, & storm damage expense.
*Docket No. 38951,	Application of Entergy Texas, Inc. for Approval of CGS Tariff,
Subject:	Rate Design, Competitive Tariffs
*Docket No. 42454,	Application of SPS for Revision of EECRF[1]
Subject:	Recovery of energy efficiency costs

[1] Asterick (*) denotes testimony for Texas OPC as a consultant.

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

TESTIMONY ON BEHALF OF PENNYSLVANIA OFFICE OF CONSUMER ADVOCATE	Docket No. R-2010-2161575, et. al.,	PECO Energy Co.-Electric Division Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2010-2179522,	Duquesne Light Company Base Rate Case,
	Subject:	Cost Allocation and Rate Design.
TESTIMONY ON BEHALF OF GULF COAST COALITION OF CITIES	Docket No. 38339,	Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates,
	Subject:	Cost Allocation, Rate Design, Riders.
TESTIMONY ON BEHALF OF SWEPCO CITIES	Docket No. 40443,	Application of SWEPCO for Rate Change.
	Subject:	Cost Allocation, Rate Design, Fuel Rule, Revs.
TESTIMONY ON BEHALF OF ST.LAWRENCE COTTON GROWERS	Docket No. 41474,	Application of Sharyland Utilities for Unbundled Delivery Rates.
	Subject:	Cost Allocation, Rate Design, Unbundling.
TESTIMONY ON BEHALF OF LIVE OAK TENANTS	Docket No.41987	Complaint Against Live Oak Resort
	Subject:	Sub Metering Complaint Case
TESTIMONY FOR CONNECTICUT CONSUMER ADV. (OCA)	Docket No.14-05-06	CL&P Rate Increase Application
	Subject:	Cost Allocation, Rate Design, Decoupling

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No. R-2014-2428743
Pennsylvania Electric Company	:	
	:	

VERIFICATION

I, Clarence L. Johnson, hereby state that the facts above set forth in my Direct Testimony, OCA Statement No. 3, are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: _____
Clarence L. Johnson

Consultant Address: 3707 Robinson Ave. Austin TX

DATED: 11/20/14

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