UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

RONALD J. AMEN

EXHIBIT RJA-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

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I. INTRODUCTION

Q. Please state your name and business address.

A. Ronald J. Amen. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head, SC 29926-2849.

Q. By whom and in what capacity are you employed?

A. I am a Managing Partner with Atrium Economics, LLC ("Atrium"). Atrium is a management consulting and financial advisory firm focused on the North American energy industry.

Q. Please describe Atrium's business activities.

A. Atrium offers a complete array of rate case support services including advisory and expert witness services relating to revenue recovery, pricing, integration of technology, distributed generation, and affiliate transactions. We have extensive experience in rate case management; revenue requirement development; allocated embedded and marginal cost of service studies; rate design and rate alignment; and affiliate and shared services.

We have appeared as expert witnesses on behalf of energy utilities in regulatory proceedings across North America supporting financial, economic, and technical studies before numerous state and provincial regulatory bodies, as well as before the Federal Energy Regulatory Commission ("FERC"). The Atrium Team has extensive background and experience both in management positions inside electric and gas utilities and as advisors to our clients.

Q. On whose behalf are you testifying?

A. Unitil Energy Systems, Inc. ("UES" or "the Company") retained Atrium to conduct the allocated class cost of service study (ACOSS); the marginal class cost of service study (MCOSS); the revenue apportionment and revenue targets by class; the rate design for existing rate classes; Light Emitting Diode ("LED") rates; and Time Of Use ("TOU") rates for the domestic class and for Electric Vehicle ("EV") charging. I am supporting the Company's ACOSS, MCOSS, and revenue apportionment and revenue targets by class. My colleague John Taylor is supporting the Company's rate design proposals, including new LED rates, the Domestic TOU rate and TOU rates for EV charging.

Q. What has been the nature of your work in the utility consulting field?

A. I have over 40 years of experience in the utility industry, the last 23 years of which have been in the field of utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before numerous utility regulatory bodies across North America and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement.

Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Appendix A.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. No.

Q. Please summarize the topics addressed in your testimony.

A. My testimony discusses the role of the ACOSS and MCOSS in providing guidance toward designing economically efficient rates. Cost causation is a fundamental principle for these studies. Understanding cost causation requires an in-depth understanding of the planning and operation of the utility system, as well as the basic economics of the electric system components.

The ACOSS and MCOSS prepared for this case reveal how UES incurs costs to serve its various classes of customers. The single most important conclusion from the cost studies is that in order to collect the costs from customers who cause the costs to be incurred, rates must better reflect the nature of these costs.

II. COST OF SERVICE STUDIES

Q. What are the purposes of cost of service studies?

A. The primary purpose of a cost of service study is to allocate a utility's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. In other words, a cost of service study is an analysis of costs that assigns to each class of customers its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

The cost of service study provides a reasonable starting point for policy makers to decide the portion of common costs borne by each class of service. In addition, it must be remembered that other constraints impact policy decisions, such as the concept of just and reasonable rates and non-discriminatory rates. The cost analyst must rely on who causes costs and how those costs are recovered within a class of customers as the basis for determining rates that result from the cost of service study.

The cost of service study is useful in identifying cost causation that is a critical element of the allocation of costs between classes and customers within the class, and for adjusting rates to reduce or eliminate cross subsidies that result in rates that are not just and reasonable. A fully unbundled cost of service study provides critical information for the design of just and reasonable rates.

III. PRINCIPLES OF COST CAUSATION

Q. Please discuss the principle of cost causation.

A. Cost studies are a basic tool of ratemaking. Just and reasonable rates must avoid undue discrimination and must reflect the principle of "user pays," also known as "cost causation," which is another way of saying those who cause the costs should pay the costs. The development of unbundled costs permits regulatory review of the costs that are the same on average for customers in the class. The term "on average" is used because no two customers are exactly alike. Therefore, costs are determined, and cost-based rates are set, for "typical" customers grouped by similar demand and usage patterns.

If those costs are not recovered in the customer charge or basic service fee as they should be, the customers with more than average energy consumption subsidize the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess the rates to determine if they are just and reasonable and do not discriminate based on the rate design.

In order for rates to be efficient the concept of customers being charged for the distinct services they use is important since different customers use different services. Further, the costs of those services may be different because of the different load characteristics of customers in a class. Both cost allocation and rate design play a role in efficient rates.

A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system.

Q. Why is the principle of cost causation important?

A. Cost causation is the key element to selecting an allocation method. This has been the standard by which an allocation method is evaluated, and it continues to be the gold standard for assessing cost allocation. The principle of cost causation is also relevant for analysis within classes of customers where each customer must have rates that, on average, match the cost of service for that customer.

Q. What are the measures of demand that may be used in cost allocation?

A. The demands used to develop allocation factors essentially fall into three fundamental categories as follows:

1. Coincident Peak ("CP") Methods
2. Non-Coincident Peak ("NCP") Methods
3. Average and Excess Demand ("AED") Methods.

Q. Please briefly summarize the basic assumptions underlying each potential allocator.

A. The following table summarizes the basic provisions of each category of allocation methods:

<u>Table 1</u>

<u>Cost Allocation Methods Summary</u>

Allocation Method	Assumption about Cost	Allocation Factor
CP	Peak loads drive costs	Class coincident demand
AED	Peak loads and energy usage drive costs	NCP and load factor
NCP	Class or customer peaks drive costs	Class or customer NCP

Q. What methodology was used in the preparation of the UES cost of service study?

A. A combination of a) the class NCP demands, and b) the sum of the customers' NCPs for each class of service were used in developing the UES ACOSS.

IV. DEVELOPING CLASSES OF SERVICE

Q. How are classes of service determined for use in cost of service and rate design?

A. Historically, classes of service have been based on the principle of homogeneity[1]. Typically rate classes have included such categories as:

- Class of service – residential, commercial, industrial
- End-use classification – residential regular, residential all-electric
- Voltage level of service, i.e., secondary, single-phase primary, three-phase primary
- Quality of service – firm or interruptible
- Type of service – full requirements, partial requirements

Having customers with the same usage characteristics allowed relatively simple rate designs to track costs closely with a limited number of rate elements such as a customer charge and a volumetric energy charge.

[1] Definition: Of the same or similar nature or kind; uniform throughout the structure or make-up. Webster's II University Dictionary (1984).

Q. Are there reasons to question the relevance of current customer class structures?

A. Yes. The electric supply market has been changing for years. Perhaps the most important change has been the development of a mix of competitive service offerings for electricity generation coupled with the continued monopoly status of other components of electric utility service. Where there is a mix of competition and monopoly in the market, the definitions of classes of service and the related rate structures must evolve to provide for more efficient electricity markets and for rates to be just and reasonable, and not unduly discriminatory. The first step in this process is developing fully unbundled cost of service studies as the foundation for properly designed rates.

Q. How should classes of service be developed in the future based on the unbundled cost of service?

A. It turns out that some of the same concepts that matter today will also matter even more in the future as class costs are evaluated. The following list provides the major elements that will be used to develop rate classes:

1) Voltage level of service
2) Size of load
3) Unique load characteristics and service attributes
4) End-use load characteristics.

The voltage level of service is necessary to reflect the cost of distribution facilities and the loss adjustments for both energy and capacity related costs at the point of delivery. The size of the load will be a driver of the appropriate customer related costs because of the higher total cost of local facilities. Unique load and service attributes also impact costs. For customers that have one of a kind service requirements there will be a need to ensure cost recovery for the unique facilities required to provide service. Certain end use load characteristics must also be identified and managed such as leading or lagging power factor considerations or extra reliability requirements as examples.

V. THE COST OF SERVICE STUDY PROCESS

Q. What are the basic steps in developing a cost of service study?

A. Cost of service studies use a three-step process as follows:

1. Functionalization
2. Classification
3. Allocation

Q. Please explain the functionalization process.

A. A systematic process for identifying functions is used based on the traditional categories of production, transmission, distribution, and customer. To the extent permitted by the accounting data, this functionalization may include subcategories such as primary distribution and secondary distribution and directly assigned dollars based on unique facilities that need to be assigned rather than allocated. The process of functionalization has become a more robust and simplified process with the use of accounting data as reported under a uniform system of accounts ("USOA"). That is not to say that all of the issues have been resolved. Certain accounts such as intangible plant still require some analysis to functionalize individual cost elements in the account for some utilities. The typical functions used in a cost study are as follows:

- Production/Supply
- Transmission
- Distribution[2]
- Customer

Each of these functions is described below.

The Production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The Transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the distribution grid and to move power from generation to load.

The Distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. In

[2] It is common for distribution costs to be broken out by voltage levels. In UES's case – primary and secondary

recognition of this fact, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are allocated between distribution and customer service accordingly.

The Customer function includes plant and expenses caused by individual customers. Customer service includes meters, service lines, meter reading and billing. It also includes a portion of the distribution system including transformers, conductor, and poles.

Q. Please describe the cost classification step?

A. Cost classification is driven by as detailed an analysis as the accounting data permits. Costs are classified as demand, energy, and customer. Only costs that vary with energy are classified as energy. The costs classified as demand are those costs that are a function of some measure of demand. Customer costs are those costs that vary with the number of customers. For some of the costs associated with the distribution system, costs must be split between the portion that is demand related and the portion that is customer related. That split is based on the principles of cost causation, as discussed above. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built, and operated.

Q. Please elaborate on the nature of the cost classification categories.

A. *Demand* costs are capacity related costs associated with plant that is designed, installed, and operated to meet maximum electric usage requirements such as larger transformers or more localized distribution facilities, which are designed to satisfy individual customer maximum demands. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Energy costs are those costs that vary directly with the production of energy such as fuel costs; other fuel related expenses or purchased power expense.

Customer costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer Costs are largely a function of the number and density of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Q. Can costs be classified into more than one category?

A. Yes, as mentioned earlier. For example, some distribution costs may have both a demand and a customer cost component.

Q. Please describe the allocation process?

A. Allocation is based on the factors that cause costs to be incurred. Cost studies use two types of allocation factors: external factors and internal factors. External allocation factors are based on direct knowledge from data in the utility's accounting and other records such as the load research data. Energy allocation factors are based on the class energy consumption and adjusted for losses to equate to total energy production. Another example of an external allocation factor is allocation of distribution system costs, both the demand and customer components. The costs of distribution facilities are known and assigned directly to the distribution function as substations, poles, towers, and fixtures, overhead and underground conductors, transformers, service lines and meters. Once assigned to distribution, the poles and conductors are allocated using the minimum system to classify the costs between demand and customer related costs and then are allocated on external allocation factors. Demand allocation factors are based on load research data that is used to calculate the demand for the sampled rate classes and is adjusted to equal system peaks. For some classes the peak data for the class comes from billing data and represents the sum of actual customer loads occurring at the system peak. As smart meter technology becomes more ubiquitous, the need to estimate the class load will no longer be necessary as meter data will be available. Internal allocation factors are based on some combination of external allocation factors, previously directly assigned costs, and other internal allocation factors. For example, the allocation factors for property insurance costs are based on plant investment amounts assigned to each function; therefore, it is necessary to compute the amount of plant by function before property insurance costs can be assigned.

Q. How do the principles and processes you have explained pertain to fixed costs and variable costs?

A. In the utility ratemaking context, fixed costs include all of those costs that do not vary with the amount of energy consumed by customers and constitute the vast majority of the cost to provide service.

Variable costs include only those costs that vary with the amount of energy consumed by the customers. In other words, variable costs relate directly to how much power is actually consumed; these costs include fuel, the energy component of purchased power costs, reagents used in generation for the operation of emission control systems, and any O&M costs directly related to energy production.

All other costs incurred by the utility are fixed costs because the utility must incur them in order to be capable of providing service whether or not customers actually consume any energy.

Q. How do the functionalized and allocated costs in an ACOSS fit into the fixed and variable cost framework?

A. The only variable costs in UES's cost of service are those designated and allocated as production-energy costs and transmission-energy costs from transmission by others. All of UES's other costs are fixed. That would include the following categories:

- Electric Procurement Supply[3]
- Radial Transmission[4]
- Distribution demand (Primary and Secondary), and
- Distribution customer (Primary and Secondary)
- Customer Service[5]

For UES, the transmission costs are recovered in the External Delivery Charge ("EDC") mechanism and are thus excluded from base rates. While all of these costs are fixed, most are recovered based on energy consumption.

Q. Is it common for utility rates in general to properly reflect fixed and variable costs of providing service?

A. No. In fact, it is rare for the rates of a utility like UES to perfectly reflect the fixed and variable costs of providing service. For many utilities, significant portions of total fixed costs are often recovered in variable charges. This is particularly true for the residential and small commercial or general service rate classes. This treatment of a portion of fixed cost as a variable cost creates pricing inefficiencies that can have adverse consequences to utility customers under certain conditions.

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[3] Until Energy assigns Prime Movers to this function.

[4] Unitil Energy has no transmission plant but does book some labor-related O&M expenses.

[5] Unitil Energy has two customer functional categories, Customer Accounts and On-Site.

Q. How does the incorporation of fixed costs into variable charges affect customers?

A. The inclusion of fixed costs in the variable charge sends an inaccurate price signal to customers. This price signal overstates the value of energy consumption and understates the costs necessary to be able to provide service regardless of how much energy the customer uses. This inaccuracy essentially overcompensates the customer for energy conservation/efficiency and under compensates the utility for the assets and facilities that are needed to provide customers with any amount of electric service. Conversely, this inaccuracy also overcompensates the utility for its fixed costs when customers use large amounts of energy. The result of this inaccuracy is essentially an intra-class mismatch of costs and revenue.

When a customer conserves energy, the utility produces less energy, and thus incurs less energy production cost (e.g., fuel or purchased power). This should amount to a dollar-for-dollar savings for both the customer and the utility. However, when a customer conserves energy, the utility does not incur lower fixed costs, like capital investments in substations and poles (distribution demand), or meters, billing, or customer service representatives (customer). When some customers are able to reduce their energy consumption, they avoid paying fixed costs that the utility continues to incur to provide the customer with needed services. Ultimately, those costs will be shifted to other customers.

VI. SELECTION OF CLASS COST OF SERVICE FOR UES

A. Characteristics of Distribution Plant

Q. Please discuss the nature and characteristics of distribution plant

A. The UES system distribution plant consists of different facilities that have different cost causation factors. The reason for this conclusion is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility cost is directly the result of the individual customer and is caused by the customer unrelated to demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component. Transformers are sized to meet the NCP of the customers served from a single transformer but utilities do not install every possible size of transformer. Instead, utilities use a standard set of transformer sizes and one of those is the transformer that represents the minimum size. Transformer costs exhibit significant scale economies. This means that the smallest size of transformer costs much more per kVa than larger transformers. Given the fact that utilities typically use a minimum size of transformer, the cost of the minimum size is related to a customer since every customer requires transformer capacity.[6] For transformers larger than the minimum size, the remainder of transformer cost is related to

[6] For larger customers, the customer may provide its own transformers. These distinctions are typically reflected either as transformer credits in rates (UES's method) or a separate rate schedules for different service classes defined based on use of distribution facilities.

demand. The portion related to demand is based on the customers served from each transformer and represents a much smaller share of costs than the customer component. Given the proximity of the customers to transformers, there is limited diversity for transformers that may serve a few customers and no diversity if a transformer serves only one customer. Thus, transformer demand is related to the individual customer NCP. The NCP for the system based on the sum of individual customers is much higher than either the system coincident peak or the sum of the class NCPs. For facilities located close to the customer such as transformers, secondary conductor, secondary poles, and even single-phase primary conductor, both a customer component and the individual NCP allocation factor is the most appropriate. As the cost becomes more remote from the customer, it is the class NCP that drives the costs. This applies to the demand portion of primary poles and primary conductor. The substation related investment is based on the class NCP allocation factor alone. In fact, any number of substations peak at different times and even different seasons from the coincident peak demand of the utility.

Distribution costs differ based on the portion of the system used by different classes of service. In fact, some customers make no use of the distribution system at all. Where customers own their own substation and connect directly to the transmission system, the customer causes no distribution costs for the utility. These customers are typically served either through special contracts or under a transmission service rate schedule. Further, not all customers use the same level of distribution facilities. For example, customers may own their own transformers. Some larger customers may be served at primary voltages only and thus use no secondary facilities. For very large customers, the customer may use only the three-phase primary system operating at the upper end of voltages for the primary system. Where the utility data supports the identification of the facilities at a detailed level, it is possible to reflect the actual facilities used. Distribution costs may differ based on the facilities required to serve some customers. Some loads require extra facilities to serve a load based on unique load characteristics such as low power factor or frequency regulation for intermittent loads. In that case, the customer may require special rate provisions such as a facilities charge to pay for the extra investment. When customers who have common load characteristics, i.e., "homogeneous" load characteristics, they may warrant a separate class of service. This is particularly important to recognize that partial requirements customers require their own class of service because of the unique load characteristics of this type of customer.

For distribution costs found in Account Nos. 364 – 374 either all or a portion of the costs are customer related because they are caused by customers. There is no basis for arguing that Account Nos. 369 – 373 are not customer related. For Account No. 369 – Services, each customer has a service designed to meet that customers own load characteristics. The service line is dedicated to the customer to meet the load of the customer premise. Services are dedicated to a customer and each customer causes the cost of its service even if the customer never consumes any energy beyond a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory customer charge the result is not just and reasonable and is a case of undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system.

Electricity will not flow into a premise without an electric meter (Account No. 370). For smaller customers, meters are virtually the same for each customer. As customers increase in size, the meter installation becomes increasingly complex and the cost of meter sets increase. In addition, Account Nos. 371 - 373 represent facilities that are also customer related. In the case of these facilities, the customers who request the extra service provided by these facilities typically pay for these directly as in the case of Account No. 373 related to outdoor lighting. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system without and cannot receive service without a minimum level of distribution services provided through the assets in Account Nos. 364 – 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve these customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The minimum system concept assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs.

B. Allocation of Customer Costs

Q. Please discuss the allocation of customer related costs.

A. There are costs other than distribution plant that are customer related and should be included in the customer cost allocation. First, a portion of the O&M associated with the distribution plant accounts that are allocated on both customer and demand are appropriately allocated to customer costs. In addition, where all of a plant account is allocated as customer related, all of the associated O&M costs should also be allocated to customer costs. Second, customer service-related expenses should be fully allocated to customer costs. Third, a portion of general plant costs should be allocated to customer costs to include such items as customer service facilities and other types of facilities such as the meter shop, stores and tools and equipment. Fourth, a portion of administrative and general ("A&G") expenses should be allocated to customer costs as well. The allocation of general plant and A&G costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs but pension and benefits cost and other items related directly to employee costs.

C. Distribution Plant

As noted above, distribution plant is classified as demand, demand and customer, or just customer depending on the costs. Each component of the distribution system requires a different allocation factor based on the classification of the costs and the role that diversity plays in causing the costs. For plant functionalized as distribution plant and found in accounts related to facilities associated with distribution substations (Account Nos. 360 – 363), the plant is classified as demand and is allocated on the class contribution to the system NCP. Substations reflect the diversity of the customers served out of a particular substation. Typically, substations have different mixes of customer class and loads. As a result, substations often peak at times different from the system peak loads. Some substations may even have peak loads in a different season of the year than the system. The use of the sum of the class NCPs accounts for the differences that occur in the capacity demand on substations. Diversity of load on the distribution system is greatest at the substation level where multiple feeders serve a variety of customers and loads.

For distribution facilities in the accounts related to the power lines (Account Nos. 364 – 368) where power is delivered to the interconnection point with the customer, the costs are classified as both customer and demand. While there are several methods to classify these costs between customer and demand, the minimum system approach is the most consistent with cost causation because it represents the actual cost of connecting a customer to the system to serve the minimum load that meets the parameters of the approved line extension policy. Any investment, greater than the minimum system, must be related to the customers' maximum demands on that portion of the system. Thus, in addition to the customer allocation, the demand allocation is based on the sum of the customers' NCPs for each class of service. For the remainder of the distribution accounts (Account Nos. 369 – 373), the costs are classified as customer and are allocated on a customer basis with as much direct assignment of costs as possible. The final distribution account (Account Nos. 374) is related to amortization of PCB related costs and is allocated based on the transformer investment.

D. Other Allocation Factors

Q. Please describe other types of allocation factors within the ACOSS.

A. There are numerous other allocation factors in the ACOSS. Fuel and purchased power expenses are allocated on energy as are certain fuel related O&M costs. O&M costs for the various plant functions are allocated as the associated plant is allocated. There are a number of internal allocation factors that distribute costs according to the factor or factors causing those costs. Thus, an expense like pension expense is allocated on payroll and flows through to the payroll cost component of O&M accounts and ultimately is allocated as the plant is allocated. General plant investments are allocated on labor as well. Intangible plant is analyzed to determine the cause of costs and the components are classified to customer or demand based on the nature of the costs. In each case, the intent of the chosen classification and allocation is to reflect the most appropriate cause of the costs given the level of detail available to analyze the costs.

VII. SUMMARY OF THE ALLOCATED COST OF SERVICE STUDY

Q. Please summarize the results of the recommended cost of service study.

A. The following **Table 2** provides a high-level summary of the results of the ACOSS. The table 2 shows the rate of return for each rate class based on current rates as well as the system overall return and the revenue deficiency or excess for each rate class at the uniform system rate of return.

TABLE 2

RATE OF RETURN AND (REVENUE DEFICIENCY) / EXCESS BY RATE CLASS

(A)	(B)	(C)
RATE CLASS	**RATE OF RETURN BY CLASS**	**REVENUE EXCESS OR (DEFICIENCY) IN THOUSANDS**
D - DOMESTIC DELIVERY SERVICE	-1.01%	($17,935)
G2 - REGULAR GENERAL SERVICE	15.14%	$3,564
G1 - LARGE GENERAL SERVICE	16.00%	$1,937
OL - OUTDOOR LIGHTING	21.94%	$443
TOTAL SYSTEM	4.01%	($11,992)

Q. Do these results provide guidance for the allocation of revenue requirements in this case?

A. Yes. Cost of service is a useful tool for determining the allocation of the revenue deficiency to each rate class. Cost of service is not, however, the only consideration in determining the portion of the revenue deficiency allocated to each rate class. Other considerations include principles such as gradualism, competitive considerations, standalone costs and avoiding or minimizing the potential for compromising the integrity of current rate classes.

Q. Has UES taken the above factors into account in recommending the level of rate increase for rate classes?

A. Yes. The process for determining the revenue increase for each class is addressed in **Section VIII** of this testimony.

Q. Please describe the ACOSS schedules attached to this testimony.

A. Six schedules provide further details of the ACOSS that include the following information:

- Schedule RJA – 2, consists of two pages and presents the results of the class cost of service study for the test year. Class rate of return and net income may be found on page 1, and the revenue requirement for each class at the uniform rate of return by rate schedule is shown on page 2 of this schedule.
- Schedule RJA – 3, provides a single page illustration of the process followed to develop the Company's proposed class revenue allocation.
- Schedule RJA – 4, consists of 3 pages and presents the ACOSS unit cost report.
- Schedule RJA – 5, consists of 3 pages and provides the summary of the ACOSS external allocation factors.
- Schedule RJA – 6, consists of 5 pages and provides a description of the functionalization and classification of the USOA accounts.
- Schedule RJA – 7, presents a single page summary of the Minimum System Study.

VIII. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate UES's proposed revenue increase of $11,992,393 to its customer classes.

A. The apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for UES's customer classes.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of UES's interclass revenue proposal?

A. Yes. Using UES's proposed revenue increase, and the results of its ACOSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with UES personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option that I evaluated under UES's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00 ("Unity"), as shown in Schedule RJA-3, Proposed Revenue Allocation, under *Revenues at Equalized Rates of Return*. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

A second option I considered was assigning the increase in revenues to UES's customer classes based on an equal percentage basis of its current non-gas revenues (*Scenario A, Equal Percentage Increase*, in Schedule RJA-3). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the ACOSS results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of UES's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). In fact, the disparity in cost responsibility between the classes was widened. While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop UES's class revenue proposal.

A third option was to exempt the customer classes that are above parity under current rates from receiving any revenue increase. This option would preserve the current parity ratio for the G2 – Regular General Service and G1 – Large General Service classes (*Scenario B*, *No Class Increase Above Parity*, in Schedule RJA-3).

Q. What was the result of this process?

A. After further discussions with UES, I concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all but one of UES's customer classes: D – Domestic Delivery Service, G2 – Regular General Service, and G1 – Large General Service, as shown in Schedule RJA-3 as *Scenario C, Minimum Class Increase of 50% of System Average*. In the case of the D – Domestic Delivery Service class, the revenue adjustment ensures their proposed rates will move class revenues closer to the allocated cost of service for the class. The proposed revenue increase to the D – Domestic Delivery Service class will improve the class' revenue-to-cost ratio from 0.64 to 0.83, below unity (1.00) at the Company's proposed ROR of 7.88%. The ACOSS results for the remaining customer classes indicate their respective class rates of return are above the system average rate of return at both the Company's current and proposed ROR levels. While this would suggest the need for revenue decreases in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00), as shown in Schedule RJA-3 under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential Service class has led me to conclude the Company should refrain from revenue reductions for the G2 – Regular General Service, and G1 – Large General Service customer classes, or alternatively, exempting these classes from revenue increases (*Scenario B*). Instead, the proposed respective revenue adjustments of 50% of the system average increase will mean these two classes will be higher than their current parity ratio levels relative to unity. However, the interclass subsidy gap between these classes and the D – Domestic Delivery Service will be narrowed. I have refrained from proposing a revenue increase for the Outdoor Lighting customer class.

Q. What was the reason for exempting the Outdoor Lighting class from a revenue increase?

A. UES is anticipating a transition from the legacy outdoor lighting fixture technology (Mercury Vapor, Sodium Vapor, and Metal Halide) currently deployed in its distribution system, to new LED technology over the course of the next few years, which should reduce outdoor lighting service costs, in addition to lower energy costs. Replacement of the legacy light fixtures with LED light fixtures will reduce O&M costs associated with a longer maintenance cycle, currently five years for replacement of photo receptors and light bulbs. The expected maintenance cycle for replacement of photo receptors in the LED light fixtures will range from 10 to 13 years. The LED fixtures also have an extended useful life over the various legacy light fixtures. Therefore, the Company does not wish to increase revenue to the Outdoor Lighting class at this time and further exacerbate the current revenue surplus provided by this class when the proposed rate of return with no revenue increase will be over 2.5 times the system average return at 20.54%, the largest of any class.

Q. Please summarize the overall benefit provided by your proposed class revenue apportionment.

In summary, the preferred revenue allocation approach in <u>Schedule RJA-3</u>, *Scenario C* results in reasonable movement of the Residential class revenue-to-cost ratio toward unity or 1.00, while providing moderation of the revenue impact on this class by requiring some level of revenue increase responsibility from the G2 – Regular General Service, and G1 – Large General Service customer classes for the Company's total proposed revenue requirement. From a class cost of service standpoint, this type of class movement, and modest reduction in the existing class rate subsidies, is desirable.

IX. UNBUNDLED COST OF SERVICE

Q. Does the cost of service study provide useful guidance in developing rate structures and rate levels?

A. Yes. When a cost of service study is fully unbundled another output from the study is the cost for each service actually provided. From the cost of service study, we have prepared Schedule RJA–4, which summarizes the functionalized and classified rate base and revenue requirements for each rate class on pages 1 and 2 of the schedule; and presents a summary of unit costs for each rate class by function and cost classification on page 3. These values form the basis for beginning the process of designing rates.

Q. How were these unit costs calculated?

A. For each functional category of costs permitted by the detailed cost of the utility, the cost study calculates the costs classified as demand, energy or customer and sums those costs. The limit on unbundling details is based on the type of account information provided. For example, if detailed data exists to unbundle distribution assets into primary and secondary facilities, the demand component of each voltage level of distribution service may be unbundled. Each rate is based on the unit costs resulting from the allocation of class costs in each classification.

Q. Please explain how the unit costs can be used for rate design.

A. The unit costs provide useful information for the design of portions of tariff services, in particular for establishing cost-based customer charges. The unit costs also can be used to design demand charges where either interval metering is available or algorithm-based billing demands can be determined. Demand based rates provide for a charge based upon the maximum demand imposed by a customer on the utility's system within a specified time period, which establishes both the utility's responsibility to serve and the customer's obligation to pay for that level of service.

Q. Why is it important to determine unbundled costs?

A. The electric industry has been evolving into the mixed monopoly and competition model as a result of competitive supply options, including distributed generation ("DG"). DG can take many forms, including renewables such as wind or solar, combined heat and power, fuel cells and other forms of generation. Each of these forms of DG makes different use of utility service in general and even different uses within the same technology all based on the economics of the competitive options.

Historically, most all utility customers could be identified as full requirements customers; that is, the customers purchased all of their electric capacity and energy needs from the utility. A single rate applied to a homogeneous group of customers was adequate to recover the costs of this service. Today, more customers want to choose to be partial requirements customers. These customers want to explore competitive supply and self-generation options for a portion or all of their energy requirements. In this mixed monopoly and competition model, in order to avoid subsidization by non-DG customers to DG customers, it is important that customers who elect to self-supply a portion of their energy needs continue to pay the costs not avoided by the utility. Efficient decisions require that customers understand and pay for the costs of the portions of the system they use and any additional costs they cause the system to incur to support their technology being interconnected to the system.

In an environment of increasing DG penetration, current rate structures do not provide economically efficient price signals to customers. Instead, current structures create artificial and unsustainable cross-subsidies that result in misallocation of resources. In addition, rates as they are currently designed permit undue discrimination for customers using the very same services but paying different effective charges for those services.

Q. What services will a utility provide in the mixed monopoly and competition concept?

A. As long as the customer is connected to the utility system the utility must provide that connection capacity, and that connection capacity must be large enough to deliver service to the customer based on the maximum demand of the customer. Additionally, the utility will need to meter and bill for service that is provided and to account for energy delivered by the DG customer to the utility. Thus, customer-related costs will also continue and may even increase when customers install DG.

Since the maximum demand of a partial requirements customer may be no different than a full requirements customer, the partial requirements customer will pay far less to have the utility available to provide service than a full requirements customer when the fixed costs associated with standing ready to provide service are in per kWh charges. The simple reason is that a class that includes both full requirements customers and partial requirements customers is no longer homogeneous. Even separating the classes cannot solve the fundamental issue that different customers require different services and even different levels of those services. Rates need to be designed to provide an economically efficient and just and reasonable solution to the issue even if the class of service does not change.

Q. How does the recovery of capacity costs through demand charges benefit customers?

A. There are a number of benefits for customers as they plan their use of electric service. First, customers will know the cost of each service they use. When the cost is known, customers will be able to make better, cost-effective decisions about how they use both the utility services and the competitive services. It is important that customers really understand how an investment will change their utility costs before they spend their money on new technology.

Second, when customers pay the actual costs they impose on the utility, both the utility and the customers make better long-term decisions about resource requirements. These decisions have a much broader impact than individual customers and go to the development of the optimal plan for the utility to meet its obligations in the future given the existing sunk cost of assets currently providing utility services. This decision-making ultimately benefits customers in terms of a safe, reliable, and economically efficient utility system.

Finally, when customers know the cost of their decisions, they will properly evaluate the decision and minimize the cost of utility service.

X. MARGINAL COST OF SERVICE STUDY

Q Please describe the purpose for the preparation of a marginal cost of service study?

A. Marginal cost of service studies do not typically reflect actual costs but rely on estimates of the expected changes in costs associated with changes in service levels; and are therefore, forward-looking to the extent permitted by the available cost data. Marginal cost studies are most useful for rate design where it is important to send appropriate price signals associated with additional consumption by customers. Marginal cost studies can inform rate design particularly as it relates to customer and demand related costs for a utility that provides default energy services to retail customers who do not elect an alternate energy supplier. Marginal costs are also important for determining optimal seasons and time-of-use (TOU) periods when designing TOU rates.

Q. Please describe the Company's MCOSS.

Marginal cost studies focus on the change in costs associated with a small change in the number of customers or load added to the utility's system, or the cost to replace the current customer related infrastructure to continue service to an existing customer. As stated earlier, marginal costs are generally forward-looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs used in a utility's revenue requirement calculations include the following:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs.
- Additions to the utility system are lumpy, and as a result, utilities' optimal additions often include more capacity than the marginal change in customer count or customer demand.

To estimate marginal cost, the first step requires determining the change in cost associated with the addition of a new customer or load on average. Electric distribution systems (from the customer's meter up to the feeder coming from the distribution substation) are typically built using engineering design standards that take into consideration customer density and the expected design loads of those customers. Distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served ultimately, not specifically on the number of customers or their actual loads at any given moment.

The concept of a network cost provides a convenient way to discuss the marginal distribution costs. Network costs represent the cost of the interconnected facilities that serve local loads and include substations, feeders, transformers, service drops and meters. Feeders may be primary or secondary lines depending on the location of the customer and the design of the system. The customer component of these systems is related to the smallest size of the equipment that is installed to serve customers. If larger equipment is installed, the extra costs are demand related. The economies of scale in the distribution system mean that the demand related cost is much less significant than the customer component. It also means that per unit cost of serving larger customers is lower than the cost to serve smaller customers.

Q. How have you identified the minimum size components used by UES in its delivery system?

A. Yes. The distribution engineering and operations personnel at UES were interviewed to gain an understanding of the smallest standard size of facilities used. In addition, the Company's accounting function personnel were consulted to determine the fully loaded installed costs of these components. Schedule RJA-7 provides the cost of the minimum system components. The cost of substation equipment was considered fully demand related. For the primary system, transformers, and secondary system, the minimum system study was used to classify costs as customer-related or demand-related. Meters and services are considered entirely customer related. The MCOSS schedule also provides the economic carrying charge rate for each plant component. The schedule produces the marginal revenue requirement for UES associated with customer and demand related capital expenditures. The economic carrying charge rate uses UES's marginal capital costs based on the current filing. The forward-looking nature of a marginal cost study requires that the capital cost be estimated on an incremental basis not on embedded costs.

Q. Did you identify the general plant related to the minimum system?

A. Yes, the customer and demand related general plant was identified based on average embedded costs as a proxy for long-run marginal costs.

Q. Why are average embedded costs a reasonable proxy for marginal costs?

A. General plant costs do not vary directly with either demand or customers. That is the reason that in the allocated cost of service they are allocated on composite allocation factors. For example, customer growth only impacts the number of employees and therefore payroll expense when large discreet blocks of customers are added. If we used a pure marginal cost allocation factor, the payroll component growth related to customers or demand would be zero for a number of years and would be the full cost of a new employee only when the threshold number of customers requiring additional employees reached the tipping point in the level of services provided. By using an average cost value, the marginal cost study recognizes the contribution of each new customer to the future requirement of a new employee or new office space.

Q. Have you identified the customer related expenses?

A. Yes. The customer related expenses may be found in Schedule RJA-8, which presents the Company's full marginal cost study. These expenses were based on embedded costs as a proxy for long-run marginal costs. In the short run, these costs would be zero because adding one customer does not change most of these costs. However, at some level these costs would increase by an amount related to the average cost when a minimum number of customers have been added. This approach provides a reasonable proxy for the O&M related costs.

Q. Did you identify the A&G costs related to the minimum system?

A. Yes, customer and demand related A&G costs were identified based on embedded costs as a proxy for long-run marginal costs.

Q. Please summarize the results of the company's customer and demand costs on an embedded and a marginal cost basis.

A. The results are summarized in the table below.

TABLE 3

	Unit Customer Costs ($/Month)		Unit Demand Cost ($/KW-Month)	
(A)	(B)	(C)	(D)	(E)
Rate Class	Embedded	Marginal	Embedded	Marginal
D - DOMESTIC DELIVERY SERVICE	42.07	46.24	8.46	6.61
G2 - REGULAR GENERAL SERVICE	50.13	59.48	7.81	5.25
G1 - LARGE GENERAL SERVICE	148.40	151.47	7.22	4.15
OL - OUTDOOR LIGHTING	11.24	6.73	7.48	4.56
TOTAL SYSTEM	40.13	44.07	8.03	5.74

As the table illustrates, the D – Domestic Service customer-related costs calculated in both cost studies are significantly greater than the current customer charge. Thus, a customer facilities-related charge increase is warranted and consistent with the indicated cost of service. Increasing the customer charge and reducing the kWh charge is also consistent with both marginal cost pricing and achieving just and reasonable rates.

Q. Would the proposed allocation of the company's proposed revenue requirements differ based on using marginal costs instead of embedded costs?

A. Any differences would not be material. Considering the Company's proposed revenue allocation, the end result would have been the same. However, there is more long-term stability in embedded costs, and it is more reflective of the cost causation principle. Therefore, I believe the ACOSS is a more reasonable alternative.

Q. Does this conclude your testimony?

A. Yes.

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