BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF WILLIAM B. McNULTY

DOCKET NO. 130040-EI

JULY 25, 2013

Q. Please state your name and business address.

A. My name is William B. McNulty, and my business address is 2540 Shumard Oak Blvd., Tallahassee, Florida, 32399.

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

A. I am employed by the Florida Public Service Commission as an Economic Analyst in the Division of Economics.

Q. How long have you been employed by the Commission?

A. I have been employed by the Florida Public Service Commission since July 1989.

Q. Briefly review your educational and professional background.

A. I graduated from the University of Florida in 1981 with a Bachelor of Science degree in Psychology. I graduated from the University of Central Florida in 1989 with a Master of Business Administration degree. In that same year, I began employment with the Florida Public Service Commission as a Regulatory Analyst in the Division of Communications. Currently, I am employed as an Economic Analyst in the Division of Economics. During my tenure at the Commission, I have worked on a variety of issues involving all of the industries under the Commission's jurisdiction. In particular, I recently served as lead analyst in two rate cases, Docket No. 110138-EI (Gulf Power Company) and Docket No. 120015-EI (Florida Power and Light Company), on issues involving distribution cost classification proposals.

Q. Have you presented testimony before this Commission or any other regulatory agency?

A. Yes. I have testified before this Commission In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor, Docket No. 030001-EI.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to provide an overview and analysis of the Demand Only Cost Classification (DOCC) distribution cost classification method that has been historically approved by the Commission and the Minimum Distribution System (MDS) distribution cost classification method proposed by Witness William R. Ashburn in this proceeding.

Q. Have you prepared exhibits to support your direct testimony?

A. Yes, I am sponsoring the following exhibits.

1. Exhibit No. ___ (WBM-1) Chapter 6 of the NARUC Electric Cost Allocation Manual – January 1992.

2. Exhibit No. ___ (WBM-2) Past Commission Orders Addressing the Minimum Distribution System (MDS).

3. Exhibit No. ____ (WBM-3) Higher Minimum Cost Using Minimum Size Methodology.

4 Exhibit No. ____(WBM-4) Zero Intercept Regression Statistics and Summary Output.

5. Exhibit No. ___ (WBM-5) TECO Test Year Revenue Requirement and Bill Impacts: MDS Compared to DOCC.

Q. What is Demand Only Cost Classification (DOCC)?

A. DOCC is the typical method that has been approved by this Commission to classify the distribution plant and related costs included in FERC Accounts 364 (poles, towers, and fixtures), 365 (overhead conductors and devices), 366 (underground conduit), 367 (underground conductors and devices), and 368 (line transformers) for purposes of cost allocation to the various customer classes. The standard classifications of electric utility costs are demand-related, customer-related, and energy-related. The purpose of any classification methodology is to reflect cost causation. If the cost to build and maintain certain plant is incurred to serve peak load, the cost is said to be demand-related. Peak load is metered voltage levels measured by utilities through load research studies. Historically, the utilities have classified all distribution costs associated with poles, conductors, line transformers and related equipment (Accounts 364 through 368) as demand-related, or DOCC.

If the cost of building and maintaining certain plant is incurred to serve a specific number of customers rather than to serve peak load, the cost is said to be customer-related. Historically, the Commission has classified all of the distribution plant and associated costs in Accounts 369 (service drops) and 370 (meters) as customer-related.

The method used to determine the classification of costs as demand-related or customer-related is important because it determines how costs are allocated to the various customer classes, which has a direct impact on the rates different customers pay for electric service.

Q. What is the Minimum Distribution System (MDS)?

A. The MDS is an alternative method for classifying distribution plant and related costs included in Accounts 364 through 368 (poles, conductors, line transformers, and related equipment). The MDS is based on the recognition that the number of distribution poles, conductors, and transformers varies with the number of customers on the system. The MDS classifies a portion of the costs for poles, conductors, and transformers as customer-related on that basis. It does so by defining the costs of a minimum sized system needed to serve a customer or a minimum "voltage pathway," a system which is sized so small that it is capable of serving only minimal or zero demand levels. Therefore, the portion of the costs that make up the "voltage pathway" are allocated to customer classes using the customer allocator (i.e. the number of customers in each rate class divided by total customers). The customer allocator typically results in a higher allocation of costs for the residential and small commercial classes than does the DOCC allocator. Thus, the use of MDS to classify some of the costs as customer related results in assigning more costs to the residential and small commercial classes and less costs to the large commercial and industrial classes.

Q. Is there a standard reference to develop the MDS cost classifications?

A. Yes. The primary reference literature for the MDS is the 1992 NARUC Electric Utility Cost Allocation Manual (the Manual). Chapter 6 of the NARUC Manual appearing in Exhibit No. ___ (WBM-1) addresses the classification and allocation of distribution plant. Chapter 6 explains how the MDS can be used to classify Accounts 364 through 368 plant using both demand and customer classifications. It describes the two methodologies for implementing MDS (the "minimum size" method and the "zero-intercept" method). The NARUC Manual also addresses the issues that may arise under each method, and in some instances it explains how the issues may be resolved.

Q. What is the "minimum size" methodology?

A. The minimum size methodology for classifying distribution plant is based on a theoretical minimum size system that could be built to serve the minimum load of the customer. As an example, according to the NARUC Manual, the customer component for poles (Account 364) is found by multiplying the minimum size pole's average book cost by the number of poles. The balance of the account is said to be the demand component.

Q. What is the "zero intercept" methodology?

A. The zero intercept methodology for classifying distribution plant is based on a theoretical no-load electric service to the customer. This method involves creating a graph or plot of the unit costs of distribution equipment of varying capacity sizes and estimating an upward sloping regression line which passes through the zero intercept, or vertical axis, normally at some positive value. The value at the zero intercept is supposed to be a statistical estimate of the customer component of the cost for a single unit of the equipment that has, theoretically, zero capacity. This unit cost is used to determine the customer component in the aggregate for the account or the voltage level. According to the NARUC Manual, separate customer components are established for primary and secondary voltages for Accounts 365, 366, and 367, depending upon the availability of subaccount cost data. For Accounts 364 and 368, a customer component is established for both voltage levels combined.

Q. Has this Commission required utilities to use the cost classification methods identified in the NARUC manual?

A. No. The NARUC manual is not mandated, but it is widely accepted as a primary reference for the assignment of costs.

Q. How has the Commission classified distribution costs since 1980, and what were its reasons for either approving or disapproving MDS?

A. The Commission has considered the MDS on 15 occasions since 1980 in the context of rate proceedings. The Commission has specifically rejected the MDS 12 times for investor-owned electric utilities (electric IOUs), approved the MDS under a settlement agreement for Gulf Power Company (Docket No. 110138-EI), and approved the MDS for Choctawhatchee Electric Cooperative (Docket No. 020537-EC). Most recently, the Commission approved the Florida Power and Light Company revised settlement based on DOCC. In each case wherein the Commission denied requests for the MDS cost classification, DOCC was the accepted method by which distribution costs were classified. A list of the Commission’s past orders addressing the MDS appears in Exhibit No. __ (WBM-2).

Q. Has evidence been presented, either in this case or in recent dockets, which shows that the number of customers served is a causative factor for the installation of distribution poles, conductors, and transformers?

A: Yes. Utility distribution system planning documents have been presented in both the current proceeding and in the most recent FPL rate case (Docket No. 120015-EI) which clearly indicate that the number of customers to be served is a factor in the planning and construction of distribution assets, at least at the distribution secondary voltage level.[1]

Q. Is it possible to know precisely the proportion of distribution pole, transformer, and conductor costs that are customer related and demand related?

A. No. While the MDS attempts to quantify the costs of poles, conductors, and transformers which are caused by the number of customers served, the decisions made by utility distribution planners of how to build the system is best revealed by system planning documents. These documents typically are more general, perhaps containing a list of the factors to be considered when locating and sizing facilities, a chart showing the sizing of transformers according to the number of customers, or a discussion of the importance of taking into account the number of customers to be served by the asset or assets. These documents provide the best evidence that the number of customers are a partial cause of the costs, but they do not include a quantification or weighting of the reasons for installations or expansions between peak demand requirements and the number of customers served. On the other hand, post-hoc MDS calculations are designed to reveal the precise portion of the costs which are customer related. The task at hand requires distribution costs to be classified, a task which implies precision. The industry has responded with the MDS, but I believe it is

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[1] Transcript Volume No. 33, Page 4961, Docket No. 120015-EI.

important not to lose sight of the fact that, while MDS purports to be a precise methodology, it requires a knowledge as to the exact proportion of costs which are customer related and demand related which is simply not available.

Q. Does the NARUC manual identify any problems associated with the MDS the zero intercept methodology?

A. The NARUC manual identifies a problem of the zero intercept method wherein sometimes “abnormalities in the data” or “incorrect accounting data” can generate a negative value of the cost amount at the zero intercept (vertical axis). A negative value can not be interpreted and it is counter to common sense.

Q. Has TECO responded to the zero intercept methodology “data abnormalities” problem?

A. Yes. TECO has responded to the problem by relying upon replacement cost data rather than embedded cost data to conduct its zero intercept analysis of conductors and transformers. This is counter to the NARUC manual, which states that the appropriate data to use to determine the zero intercept cost is embedded cost data obtained directly from accounting records. TECO cites the analysis of Lawrence J. Vogt, P.E., in his book, <u>Electricity Pricing - Engineering Principles and Methodologies,</u> published in 2009. Mr. Vogt states that embedded cost data is often based on widely varying vintages of assets, which is the cause of the distorted zero intercept regression results and negative values of the zero intercept unit cost. To correct this problem, the author explains that the current replacement costs of all assets should be used in the regression model rather than embedded cost data in order to identify the zero intercept unit cost of the rebuilt system. A ratio of the zero intercept unit cost to total cost on a rebuilt basis is applied to total book costs to identify the customer related component of the assets in service.

Q. Does the NARUC manual identify any flaws or weaknesses in the minimum size methodology?

A. Yes. The minimum size methodology is relatively simple but is subject to the criticism that the use of the methodology may overstate the customer component of distribution costs because even the smallest conductor or transformer has some level of demand capability. Thus, demand costs at some level are still included in the customer component, meaning some level of demand costs are double-counted. The NARUC manual indicates that the zero intercept methodology may be a more accurate methodology than the minimum size methodology from a theoretical perspective because it reduces the demand capability of the asset to zero.

An illustration of this is contained in Exhibit No. ____ (WBM-3), "Higher Minimum Cost Using Minimum Size Methodology." Illustration A (Conductors) shows how TECO's zero intercept method applied to conductors generates a unit cost ($0.42/foot) which is lower than the cost of the smallest size conductor ($0.69/foot). TECO uses the zero intercept cost to develop their customer cost-related component.

Now consider Illustration B - "Poles," a hypothetical example showing how the zero intercept method applied to poles generates a zero intercept unit cost amount ($210/pole) which is lower than the cost of the smallest size pole ($300/pole), just as with the conductor example. However, in this instance the utility has chosen not to use the zero intercept method, instead choosing to simply use the cost of the minimum size pole as its unit cost for developing its customer component. The difference between the zero intercept cost and the smallest pole cost ($90) is counted as customer related cost, but it is actually demand related cost.

Q. Has TECO responded to the flaw with the minimum size methodology discussed

in the NARUC manual regarding the double counting of some level of demand costs?

A. No. TECO's costs associated with load carrying capability of the smallest pole is identified as customer related costs. TECO has not attempted any adjustments to extract the demand-related cost from the minimum size unit costs it has proposed. Allowing demand related costs of the minimum size unit to be counted as customer related costs is problematic in the same way as allowing all distribution costs of poles, transformers, and conductor to be counted as demand related costs (i.e. DOCC) when it is evident some costs are customer related.

Q. Is the zero intercept methodology a more accurate method for determining the customer component than the minimum size methodology?

A. It is likely, but not certain, because the zero intercept methodology as implemented has an additional problem beyond that identified in the NARUC manual. Utilities sometimes develop customer components with the zero intercept method using only a few observations in their regression models. This means the results of their model may have a very low level of statistical reliability.

For example, TECO performed its zero intercept analysis of primary conductors based on only three different size conductors, and the result of the regression is a positive zero intercept unit cost ($0.42), but the accuracy of that unit cost estimate is very low. This is evidenced by the 90 percent confidence interval for the zero intercept unit cost, which ranges from -$0.01 up to $0.86, as shown in Exhibit No. ___ (WBM-4), "Zero Intercept Regression Statistics and Summary Output." This means that there is a 90 percent chance that the true value of the zero intercept unit cost is contained within this range, but the range is very large, due to the fact that it is based on so few observations.[2] Zero intercept models with too few observations such as this are not very precise.

Q. What are TECO's proposed customer related components of its distribution costs in this proceeding using the MDS?

A. Using the MDS analysis, TECO proposes in this proceeding to classify 64 percent of its Account 364 costs (poles, towers, and fixtures), 24 percent of Account 368 costs (line transformers), and 9 percent of Accounts 365-367 costs (overhead and underground conductors and conduit) as customer-related. TECO proposes to classify the remaining costs in each of these accounts as demand-related.

Q. What are the revenue requirement impacts and expected bill impacts of the TECO's proposed implementation of the MDS on TECO's customers?

A. As shown in Exhibit No. ____ (WBM-5), the MDS as applied by TECO shifts revenue requirements of approximately $12.4 M to the residential (RS) class and $1.7 M to the small commercial (GS) class from primarily the general service demand (GSD) class and the lighting service (LS Energy and LS Facilities) classes. The total revenue requirement under the MDS is the same as the total revenue requirement under DOCC.

If TECO's rates were based solely on revenue requirements, the revenue requirement shift under the MDS as proposed by TECO would require TECO's RS customers to pay on average $1.67 per month more than they would under DOCC. The GS class customer would pay, on average, $2.14 per month more. The GSD class customer would pay, on average, $80.20 per month less under the MDS than under DOCC. The LS Energy class customer would pay, on average, $125.19 per month less under MDS than under DOCC, and the LS Facilities customer would pay, on average $115.98 per month less under the MDS than under

[2] The confidence interval is based on the assumption that the population of conductor sizes is normally distributed, wherein the population distribution forms a bell-shaped curve.

DOCC. See Exhibit No. ___ (WBM-5).

Q. What information should the Commission consider if it determines that an MDS methodology should be implemented in this case?

A. Primarily, I would recommend the Commission identify and evaluate each instance where TECO's implementation of the MDS differs from the methodologies recommended in the NARUC manual and whether such differences can be supported as reasonable and equitable. Implementing the MDS requires judgment in the development of the input cost data and this must be carefully reviewed in order to produce reliable results. Another area which should be reviewed is the cost treatment of ancillary costs within Accounts 364-368. Ancillary costs include the costs of such items as insulators, transformer platforms, regulators, and capacitors included in Accounts 364-368. Applying the MDS component ratio to all costs may not be advisable, since some of those assets are only demand-related and other assets are only customer-related.

Q. Beyond the technical issues pertaining to measuring cost causation, what are some of the regulatory impacts associated with the adoption of an MDS methodology?

A. The MDS provides two methods for recognizing the customer related costs in Accounts 364 through 368 which are missed by DOCC, albeit with the technical cost measurement issues noted above. Beyond those considerations, some of the consequences of the selection of cost classification methodologies involve ratemaking impacts. Rates based on DOCC feature lower customer charges and higher energy and demand charges than rates based on the MDS. Rates based on DOCC therefore provides clearer price signals for encouraging conservation than do rates based on the MDS methodology. For the same reason, rates based on DOCC also provide a customer with more control over his/her electric bill, which benefits the customer. Likewise, rates based on DOCC may reduce the incentive for seasonal customers to disconnect and reconnect service since fixed customer charges are lower under DOCC than the MDS.

On the other hand, rates based on the MDS may provide greater revenue stability to utilities. Under the MDS, rates may provide utilities a more certain and steady revenue stream as a result of higher customer charges and lower demand and energy charges, thereby reducing the utility's financial risk.

Q. Would you please summarize your testimony?

A. Yes. The classification of distribution costs in Accounts 364 through 368 (poles, conductors, and transformers) present a challenge and a dilemma for the Commission to resolve. The Commission's traditional method of cost classification, DOCC, misclassifies certain customer related costs, but the extent of misclassification is uncertain. Meanwhile, the MDS methodologies recognize customer related costs but the methodologies present significant cost measurement issues impacting the customer-related and demand-related components. Confidence in the methodology and the underlying data inputs is essential so that the Commission can reach an optimal decision regarding the appropriate treatment of distribution costs in this case.

Q. Does this complete your testimony?

A. Yes.

EXHIBITS

Chapter 6 of the NARUC Electric Cost Allocation Manual – January, 1992

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1] Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation[2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses[1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance[2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems[1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS OF DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the average installed book cost of the minimum height pole currently being installed.
- Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. Account 365 - Overhead Conductors and Devices

- Determine minimum size conductor currently being installed.
- Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- Determine minimum size cable currently being installed.
- Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.
- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. Account 368 - Line Transformers

- Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. Account 369 - Services

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.

  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (l/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to I/c cable. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.
  - Determine the feet, investment, and average installed book cost per foot for I/c cables by size and type of cable.
  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.
  - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.
  - Balance of cable investment is assigned to demand.
  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.
  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).
  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.
  - Multiply zero intercept cost by total number of line transformers to get customer component.
  - Balance of transformer investment is assigned to demand component.
  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

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.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of

maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.

APPENDIX 6-A

DERIVATION OF DEMAND ALLOCATOR THROUGH SIMULATION

The derivation of the demand allocator through simulation requires extensive data on the locations of various types of customers on the distribution system. This data may be available through the utility's transformer load management (TLM) system.

A TLM system may be used by a utility to provide data to minimize the loss of transformers from overload and to provide a data base for local area forecasts for engineering design. Such a data base can provide the location and size of line transformers, and identify the primary feeder leaving the substation that supplies each transformer. It can also provide the identity of the customer connected to each transformer and the usage levels of those customers. Additional sampling may be necessary to determine which transformers have secondary lines between the transformers and the customer service drops. In a simulation, the TLM data can be combined with the utility's load research data to obtain peak loading at points in the system not normally metered, as well as a matching set of the sales peak measurements normally made.

To calculate equipment peaks on an ongoing basis, a sample of transformers would have to be selected for load research metering, which could be projected to the total population of transformers. However, this may not be feasible because the cost of such a project could far outweigh the benefit derived. On the other hand, sales peaks calculated from existing load research sampling are available. This load research data could be used with the TLM data to simulate equipment peaks and their corresponding sales peaks. By comparing the peaks, we can select an appropriate allocator for each engineering category. The purpose of the simulation is not to calculate the allocators themselves, but to investigate the relationship between the equipment peaks and the sales peaks. This will allow us to choose appropriate sales peaks for allocating each engineering category.

From the TLM data, we can identify the specific transformer, three-phase circuit (feeder), and distribution substation serving each customer. Given the customer load profiles for each hour of a particular month, we can then add up the hourly load for each transformer, circuit, or substation, find its peak, and add totals by rate schedule to the equipment peaks. The key element of the simulation is the load profile of each customer.

How to generate a customer load profile and use it to simulate equipment peaks is shown below. Line transformers are used for illustration. After sorting the TLM data by transformer number, follow these steps:

Step 1 - Read a customer record from the TLM data file.

Step 2 - Test the transformer number to determine if a new transformer has been found. If not, proceed to Step 3; otherwise, go to Step 7.

Step 3 - From the TLM data, use the rate schedule and the KWH/day to identify a set of load profiles from the proper strata with the matching rate schedule.

Step 4 - Generate and use a pseudo-random number to select one of the load profiles within the identified set.

Step 5 - Combine the hourly loads for the selected load profile to yield the same total energy consumed in the TLM data. This is done by taking the TLM KWH/day divided by the KWH/day for the selected load profile and multiplying the result by the load for each hour of the selected load profile.

Step 6 - Add the customer's simulated hourly loads to the totals by rate schedule for the customer's transformer, and to the totals for the various sales peaks being generated. Now return to Step 1.

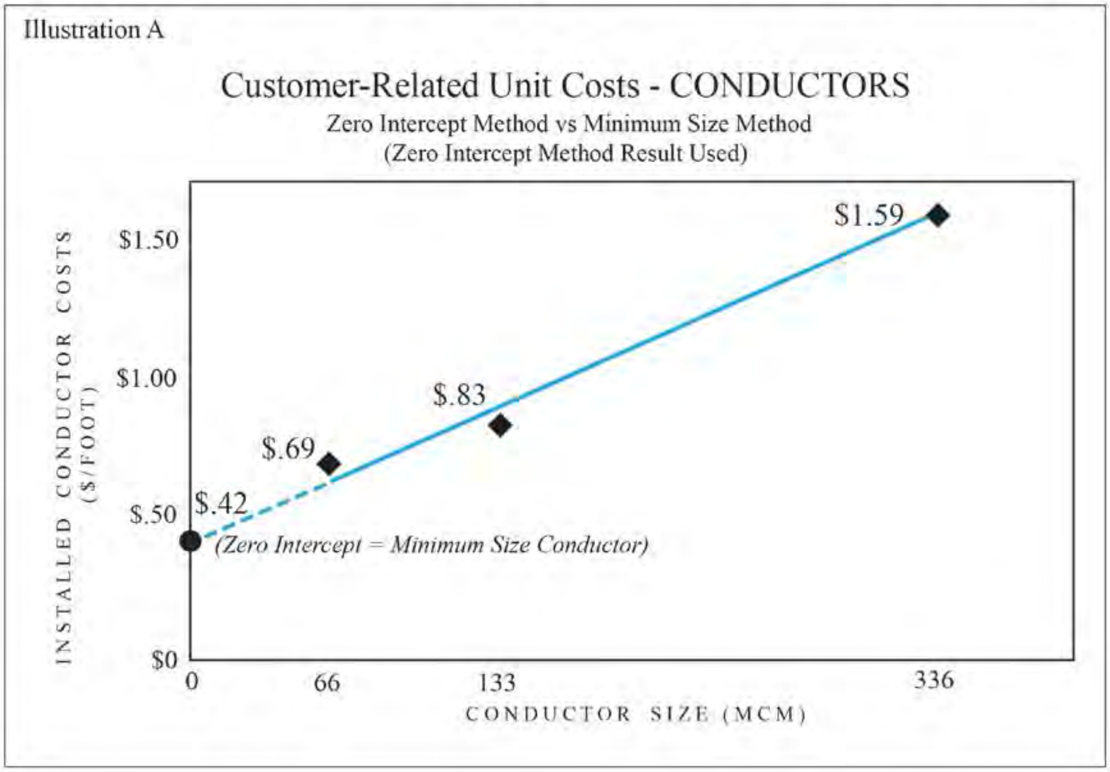
Step 7 - If you detect the end of data for a transformer, the transformer totals will contain simulated hourly loads for each hour of the month for that transformer. Search these loads to find the transformer's peak load hour. Add the loads for each rate schedule at the time of this peak to the equipment peak totals by rate schedule. Then clear the transformer totals and proceed to the next transformer in Step 3.

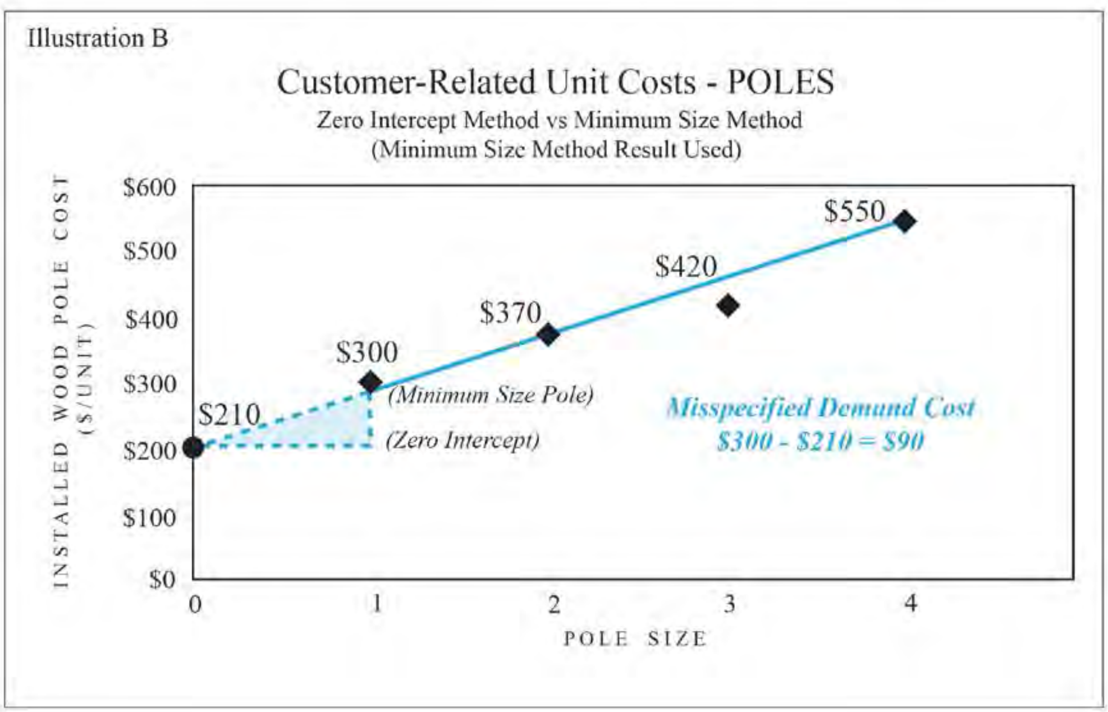
Determine the simulation of equipment peaks for substations and primary and secondary conductors in the same manner. The estimated equipment peaks for each month for each distribution component can then be compared to various class peaks (monthly coincident peaks, noncoincident peaks, etc.) that are available from load research data. The class peak factors that best match the equipment peaks should then be used to allocate each distribution component.

Past Commission Orders Addressing the Minimum Distribution System (MDS)				
No.	Order No.	Issue Date	Docket No.	Company
1	9599	October 17, 1980	800011-EU	Tampa Electric Company
2	9628	November 11, 1980	800001-EU	Gulf Power Company
3	9864	March 11, 1981	800119-EU	Florida Power Corporation
4	10306	September 23, 1981	810002-EU	Florida Power and Light Company
5	10557	February 1, 1982	810136-EU	Gulf Power Company
6	11307	November 10, 1982	820007-EU	Tampa Electric Company
7	11437	December 22, 1982	820097-EU	Florida Power and Light Company
8	11498	January 11, 1983	820150-EU	Gulf Power Company
9	11628	February 17, 1983	820100-EU	Florida Power Corporation
10	23573	October 3, 1990	891345-EI	Gulf Power Company
11	PSC-02-0787-FOF-EI	June 10, 2002	010949-EI	Gulf Power Company
12	PSC-02-1169-TRF-EC	August 26, 2002	020537-EC	Choctawhatchee Electric Cooperative
13	PSC-10-0153-FOF-EI	March 17, 2010	080677-EI	Florida Power and Light Company
14	PSC-12-0179-FOF-EI	April 3, 2012	110138-EI	Gulf Power Company
15	PSC-12-0428-PHO-EI	April 13, 2012	120015-EI	Florida Power and Light Company

EXHIBIT NO. ________ (WBM-3)

Higher Minimum Cost Using Minimum Size Methodology





ZERO INTERCEPT REGRESSION STATISTICS AND SUMMARY OUTPUT

CONDUCTORS

Observation No.	MCM Size	$/ft
1	66.63	0.69
2	133.10	0.83
3	336.00	1.59

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.99557922
R Square	0.991177984
Adjusted R Square	0.982355968
Standard Error	0.064328171
Observations	3

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.464928553	0.464928553	112.3527755	0.059883156
Residual	1	0.004138114	0.004138114		
Total	2	0.469066667			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	***Lower 90.0%***	***Upper 90.0%***
Intercept	**0.42309211**	0.068776373	6.151707183	0.102589336	-0.45079457	1.29697879	**-0.01114482**	**0.857329041**
X Variable 1	0.003435917	0.000324154	10.59965922	0.059883156	-0.000682844	0.007554678	0.001389292	0.005482541

EXHIBIT No. ____(WBM-4)
Page 2 of 2

ZERO INTERCEPT REGRESSION STATISTICS AND SUMMARY OUTPUT

TRANSFORMERS

Observation No.	KVA Size	$/unit
1	15	1689
2	25	1921
3	37.5	2145
4	50	2388
5	75	3165
6	100	3789
7	167	6019

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.995859769
R Square	0.99173668
Adjusted R Square	0.990084016
Standard Error	150.7491693
Observations	7

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	13637089.15	13637089.15	600.0837	2.11374E-06
Residual	5	113626.5602	22725.31204		
Total	6	13750715.71			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	***Lower 90.0%***	***Upper 90.0%***
Intercept	**1104.51967**	96.63777684	11.42948133	8.98E-05	856.1043522	1352.93498	**909.789871**	**1299.249461**
X Variable 1	28.50769401	1.163740574	24.49660572	2.11E-06	25.51620363	31.49918439	26.16270046	30.85268756

TECO TEST YEAR REVENUE REQUIREMENT AND BILL IMPACTS
MDS VS DOCC

Customer Class	Revenue Requirement, MDS (1000's)	Revenue Requirement, DOCC (1000's)	Revenue Requirement, MDS-DOCC (1000's)	No. of Customers	Average Annual Bill Impact	Average Monthly Bill Impact
RS	610,247	597,822	12,425	619,152	$20.07	$1.67
GS	69,499	67,751	1,748	68,159	$25.65	$2.14
GSD	366,092	379,636	-13,544	14,073	-$962.41	-$80.20
LS Energy	8,021	8,347	-326	217	-$1,502.30	-$125.19
LS Facilities	31,647	31,949	-302	217	-$1,391.71	-$115.98

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	DOCKET NO. 130040-EI DATED: JULY 25, 2013

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT the testimony of William B. McNulty on behalf of the Florida Public Service Commission was filed electronically with the Office of Commission Clerk, Florida Public Service Commission, and copies were furnished to the following, by electronic mail, on this 25th day of July, 2013.

James D. Beasley
Ausley Law Firm
PO Box 391
Tallahassee, FL 32302
jbeasley@ausley.com

Tampa Electric Company
Gordon L. Gillette, President
Paula K. Brown, Manager, Regulatory Affairs
PO Box 111
Tampa, FL 33601-0111
Regdept@tecoenergy.com

Office of Public Counsel
J.R. Kelly/P. Christensen/J. McGlothlin
c/o The Florida Legislature
111 W. Madison Street, Room 812
Tallahassee, FL 32393-1400
kelly.jr@leg.state.fl.us
christensen.patty@leg.state.fl.us
mcglothlin.joseph@leg.state.fl.us

Jon C. Moyle, Jr.
c/o Moyle Law Firm
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com

Florida Retail Federation
100 East Jefferson Street
Tallahassee, FL 32301

Gardner Law Firm
Robert Scheffel Wright/John T. La Via, III
1300 Thomaswood Drive
Tallahassee, FL 32308
schef@gbwlegal.com
jlavia@gbwlegal.com

Federal Executive Agencies
c/o Lt. Col. Gregory J. Fike, USAF
AFLOA/JACL-ULFSC
139 Barnes Drive, Suite 1
Tyndall Air Force Base, Florida 32403
gregory.fike@tyndall.af.mil

Kenneth L. Wiseman
Mark F. Sundback
Lisa M. Purdy
William M. Rappolt
Blake R. Urban
Andrews Kurth LLP
1350 I Street NW, Suite 1100
Washington, DC 20005
kwiseman@andrewskurth.com
msundback@andrewskurth.com
lpurdy@andrewskurth.com
wrappolt@andrewskurth.com
burban@andrewskurth.com

Martha C. Brown

MARTHA C. BROWN
SENIOR ATTORNEY

FLORIDA PUBLIC SERVICE COMMISSION
Gerald L. Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
Telephone: (850) 413-6187