IIEC Exhibit 4.0

**STATE OF ILLINOIS**

**ILLINOIS COMMERCE COMMISSION**

| | | |
|---|---|---|
| **CENTRAL ILLINOIS LIGHT COMPANY d/b/a AmerenCILCO** | ) | **Docket Nos. 07-0585, 07-0588** |
| **CENTRAL ILLINOIS PUBLIC SERVICE COMPANY d/b/a AmerenCIPS** | ) | **Docket Nos. 07-0586, 07-0589** |
| **ILLINOIS POWER COMPANY d/b/a AmerenIP** | ) | **Docket Nos. 07-0587, 07-0590** |
| **Proposed general increase in electric delivery service rates.** | ) | **(Consolidated)** |

Direct Testimony and Exhibits of

**David L. Stowe**

On Behalf of

**Illinois Industrial Energy Consumers**

Project 8899
March 14, 2008

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

**STATE OF ILLINOIS**

**ILLINOIS COMMERCE COMMISSION**

| | | |
|---|---|---|
| **CENTRAL ILLINOIS LIGHT COMPANY d/b/a AmerenCILCO** | ) | **Docket Nos. 07-0585, 07-0588** |
| **CENTRAL ILLINOIS PUBLIC SERVICE COMPANY d/b/a AmerenCIPS** | ) | **Docket Nos. 07-0586, 07-0589** |
| **ILLINOIS POWER COMPANY d/b/a AmerenIP** | ) | **Docket Nos. 07-0587, 07-0590** |
| **Proposed general increase in electric delivery service rates.** | ) | **(Consolidated)** |

## Direct Testimony of David L. Stowe

Cost of Service Overview ..... 3

Ameren's Cost of Service Studies ..... 8

No Recognition of the Distribution System Components that Do Not Vary with Demand ..... 9

Methods for Determining MDS Costs ..... 24

Review of Ameren's Cost Studies ..... 28

Results of AmerenCILCO's COSS ..... 30

Appendix A ..... 1

IIEC Exhibit 4.1: COSS – Revenue Cycle

IIEC Exhibit 4.2: Capacity of the Minimum Distribution System

IIEC Exhibit 4.3: Summary of Cost of Service Study as Filed and Modified

**STATE OF ILLINOIS**

**ILLINOIS COMMERCE COMMISSION**

| | | |
|---|---|---|
| **CENTRAL ILLINOIS LIGHT COMPANY d/b/a AmerenCILCO** | ) | **Docket Nos. 07-0585, 07-0588** |
| **CENTRAL ILLINOIS PUBLIC SERVICE COMPANY d/b/a AmerenCIPS** | ) | **Docket Nos. 07-0586, 07-0589** |
| **ILLINOIS POWER COMPANY d/b/a AmerenIP** | ) | **Docket Nos. 07-0587, 07-0590** |
| **Proposed general increase in electric delivery service rates.** | ) | **(Consolidated)** |

## Direct Testimony of David L. Stowe

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A My name is David L. Stowe. My business address is 1215 Fern Ridge Parkway, Suite 208; St. Louis, Missouri 63141.

**Q PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation with Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

**Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A This is summarized in Appendix A to my testimony.

**Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am testifying on behalf of Illinois Industrial Energy Consumers ("IIEC"). IIEC members have facilities of operation located in the service territories of Illinois Power

Company ("AmerenIP"), Central Illinois Light Company ("AmerenCILCO") and Central Illinois Public Service Company ("AmerenCIPS"). For purposes of this testimony, these three utilities will be referred to collectively as "Ameren" or "Company."

**Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A The purpose of my testimony is to describe my review of the Company's cost of service study or studies ("COSS"), and to recommend specific improvements that would make them more useful for determining rates in this case.

**Q PLEASE SUMMARIZE YOUR TESTIMONY.**

A My testimony describes my review of the COSS for each of the three electric companies, which are included in their respective Part 285 Schedule E-6 filings. I discuss a singular deficiency that I have found with the studies, and provide a comprehensive explanation of why that deficiency should be corrected.

I then briefly discuss the results of each study, explain where inter-class subsidies exist under present rates, and show how Ameren's proposal to apply revenue increases across-the-board exacerbates these subsidies.

Finally, I describe the modifications I made to each of Ameren's three studies to correct the deficiency I found in them. I then show the inter-class subsidies that exist under present rates using my modified study and show how the proper application of revenue increases that are based on cost of service eliminates these subsidies.

## Cost of Service Overview

**Q WOULD YOU PLEASE COMMENT ON THE BASIC PURPOSE OF A COSS?**

A After determining the total company cost of service or revenue requirement, a COSS is used to allocate the revenue requirement or cost responsibility among the customer classes. A COSS compares the cost that each customer class imposes on the system to the revenues each class contributes.

For example, when a customer class produces the same rate of return as the total system rate of return, it is paying revenue to the utility just sufficient to cover the costs incurred in serving that class. If a class produces a below-average rate of return, it may be concluded that the revenues provided by the class are insufficient to cover all relevant costs to serve that class. On the other hand, if a class produces a rate of return above the system average, it is not only paying revenues sufficient to cover the cost attributable to it, but is also paying part of the cost attributable to other classes who produce a below system average rate of return.

The class COSS is critical because, when properly conducted, it shows the cost to serve each rate class, as well as the rate of return from each class under current and proposed rates. IIEC Exhibit 4.1 provides a diagram depicting the individual steps of a COSS, and demonstrates how the COSS fits into a utility's cycle of incurring costs and collecting those costs through rate revenue.

**Q PLEASE DESCRIBE THE FUNDAMENTALS OF A PROPER COSS.**

A Cost of service is a basic and fundamental concept in the ratemaking process. In all cost of service studies, certain fundamental principles should be recognized and implemented. Of primary importance is the cost-causation principle, i.e., attributing costs to those customers or classes that caused them to be incurred.

The first step in the COSS process is to distinguish costs according to major functions, such as production, transmission, distribution, and customer service.[1] Many analysts also create sub-functions, such as primary and secondary voltage distribution lines, services, line transformer costs, etc., allowing them to segregate costs more precisely. Of the three steps in the COSS process, functionalizing costs is not only the least controversial, but is essentially completed by adhering to the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Nonetheless, the process is important because it allows the analyst to aggregate *costs associated with specific functions,* and to assign them to the customer classes that benefit from those functions.

Consider, for example, a customer that owns or rents the transformer serving its facility, and that has agreed to have its usage metered on the primary, or higher voltage, side of that transformer. Such customers (referred to as "primary customers") are somewhat unique in that they benefit from the utility's primary distribution system, subtransmission and transmission systems, customer service functions, etc., but do not use or receive any benefit whatsoever from the secondary distribution system. The cost analyst, in recognition of the fact that such customers exist on this system, will define separate primary and secondary distribution functions, thereby eliminating the possibility that the primary customers could be allocated secondary system costs.

The second step in a COSS is to classify[2] the functionalized costs based on *cost-causation* principles. Specifically, cost classification is based on whether costs vary with the quantity of energy consumed, the peak electrical demand required by

[1]See diagram, IIEC Exhibit 4.1.

[2]This step is called "classification of *costs."* All cost of service studies also include the classification of *customers* via a somewhat different mechanism.

the system or subsystem, the number of customers served, or some combination of these.

Energy-related costs are usage driven. That is, they vary in direct proportion as customers use more or less energy. Demand-related costs are incurred specifically to meet the customers' anticipated peak demand. Finally, customer-related costs are more closely related to the number of customers served than to the quantity of energy consumed or the electrical demands placed upon the system.

The third step in the COSS process is to assign or allocate the functionalized and classified costs to each class of customer, using factors that comport with the causes identified in the previous step. This step often relies upon supplemental studies of class loads, line losses, average meter costs, number of customers per class, etc., which are used to calculate the allocation ratios or factors.

For example, primary distribution substation costs, which are generally incurred to meet the combined demand of all the primary and secondary customers, would be distributed to the primary and secondary customer classes using allocation factors derived from each class's peak demand. However, secondary distribution costs, since they are not incurred to serve the primary customers, should be distributed to only the secondary customers using allocation factors derived from the peak demand of classes using secondary distribution facilities.

**Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATE DESIGN PROCESS?**

A The basic reasons for using cost of service as the primary factor in the revenue allocation/rate design process are equity, cost-causation, appropriate price signals, conservation, and revenue stability.

**Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?**

A To the extent practical, when rates are based on cost, each customer or class pays what it costs the utility to serve them, no more and no less. If rates are *not* based on cost of service, then some customers or classes contribute disproportionately to the utility's revenue requirement and provide contributions to the cost to serve other customers. This is inherently inequitable.

**Q HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?**

A Rate design is the rate-setting step that follows the allocation of costs to classes, so it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When rates are designed so that energy, demand, and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to manage their loads appropriately. This, in turn, provides the correct signal to the utility about the need for new investment.

**Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?**

A Conservation occurs when wasteful or inefficient uses of electricity are discouraged or minimized. Only when rates are based on costs do customers receive an accurate and appropriate price signal with which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted price signals.

**Q PLEASE DISCUSS THE REVENUE STABILITY CONSIDERATION.**

A When rates are closely tied to costs, the impact on a utility's earnings due to changes in customer use patterns will be minimized. Rates that are set at the level of costs result in revenue changes that mirror cost changes. Thus, from the utility's perspective, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of overall power costs. If rates are based on factors other than the cost to serve, it becomes much more difficult for customers to know what will affect their rates or why. They may lose the ability to translate expected utility-wide cost changes (such as expected increases in overall revenue requirements) into changes in their own rates. This situation introduces additional uncertainty and reduces the attractiveness of expansion, as well as continued operations in the utility's service territory, because of the limited ability to plan and budget for future power cost.

## Ameren's Cost of Service Studies

**Q HAS A SEPARATE COSS BEEN FILED IN THIS CASE FOR AMERENIP, AMERENCIPS AND AMERENCILCO?**

A Yes. A separate COSS has been filed for each of the Ameren Illinois distribution companies in compliance with the Illinois Administrative Code Part 285 standard filing requirements.

**Q HAVE YOU REVIEWED THE COSS OF EACH OF THE AMEREN SUBSIDIARIES?**

A Yes, I have. Because the COSS studies are structured and performed in near identical fashion, I will refer to them generally as the Company's COSS

**Q PLEASE EXPLAIN WHAT YOU FOUND IN THE COMPANY'S COSS.**

A The Company's COSS generally follows many of the widely accepted cost of service principles. However, they do not recognize and separately account for costs imposed by safety and reliability standards such as the National Electrical Safety Code ("NESC"); costs that comprise the minimum distribution system ("MDS").

On the other hand, Ameren's COSS recognizes and separately accounts for the multiple voltage levels at which its customers take service. This refinement significantly reduces the improper shifting of costs that generally accompanies the exclusion of MDS recognition. Even so, I believe that the Company's COSS would be much better and produce more accurate results if it were modified to recognize the MDS.

I have, therefore, made a single modification to Ameren's COSS for each of its subsidiary companies. I will explain the specific changes I made to the Company's COSS to better align it with proper cost-causation principles, I then will compare the

results of my modified COSS with those of the Company's COSS. A complete summary of Ameren's COSS, along with a similar study of IIEC's modified COSS, is provided in IIEC Exhibit 4.3.

## No Recognition of the Distribution System Components that Do Not Vary with Demand

**Q PLEASE DESCRIBE THE MOST SIGNIFICANT PROBLEM YOU FOUND IN THE COMPANY'S COSS?**

A Ameren's studies fail to recognize there are delivery service costs directly attributable to electrical industry mandated safety and reliability requirements for distribution facilities, and that do not vary with customer demand. Accordingly, those costs should not be allocated on the same basis as demand-related distribution system costs.

Absent recognition of this cost causing factor, each COSS overstates the cost responsibility of large customers, and understates the cost responsibility of small customers. Such costs should be allocated on a per customer basis, for reasons I will discuss below.

**Q IS THIS A NEW COST OF SERVICE CONCEPT?**

A No. The concept is known as the minimum distribution system ("MDS), and has been accepted as a valid consideration by numerous state public utility commissions for decades. It has also been presented in the National Association of Regulatory Utility Commissioners Electrical Utility Allocation Manual ("NARUC manual").[3]

[3]Chapter 6, Section II, pgs. 90-96.

The central idea behind the MDS concept is that there is a minimum cost incurred by any utility when it extends its primary and secondary distribution system, replaces a component on those systems, or connects an additional customer to them. By definition, the MDS system comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary wires, poles, substations, etc. The cost of the MDS, however, is only that portion of the total distribution cost the utility *must* incur to provide service to customers, it does not include costs specifically incurred to meet the peak demand of the customers.

**Q HAS THE COMMISSION ADDRESSED THE ISSUE OF AN MDS IN PAST CASES?**

A Yes, but previous presentations of the concept were heavily policy-oriented and theoretical, without sufficient evidentiary support to persuade the Commission. In Ameren's last DST case, for example, the Commission stated:

> "The MDS method fails to properly emphasize the purpose of the distribution system—that being to satisfy a customer's daily demand for electricity… The Commission also continues to believe that distinguishing the cost of connecting customers to the distribution system and the cost of serving its demand remains problematic..."[4]

**Q IF THE COMMISSION HAS REJECTED MDS PRESENTATIONS IN PAST CASES, WHY RAISE THE ISSUE AGAIN?**

A My reasons for raising the issue in this case are two-fold. First, the distortions in allocated costs resulting from the mis-allocation of customer-related costs on the basis of class demand are significant.

Second, the Commission rightfully expects, and cost analysts are obligated to provide, arguments proposing costing methods that are sound and compelling. Its

[4]Ameren Combined , ICC Dkts. 06-0070, 06-0071, and 06-0072, Final Order, November 21, 2006 at 160-161.

past rejection of traditional MDS methods indicates that the Commission has, thus far, found them to be neither. However, I believe there is information about the MDS that the Commission has not previously received or considered. In this section of my testimony, I will present that information and demonstrate the following:

1. Utilities design their electric distribution systems to comply with many criteria, not just customer's demand. Among these, safety and reliability are paramount.

2. Since a utility cannot extend its distribution system unless it conforms, at a minimum, to the industry mandated safety and reliability standards, these standards establish the MDS.

3. The total cost of the distribution system components specified by the standards does not vary with customer demand. However, it varies in direct proportion to the number of customers.[5]

4. Since the MDS is a real and tangible system, capable of serving a significant demand, it encompasses much of the customer's daily demand for electricity.

5. The costs associated with the MDS are identifiable and quantifiable, and the methods used to identify and quantify them are clear and straightforward. A cost analyst with access to the requisite utilities' records can compute the MDS costs in a reasonable and dependable fashion.[6]

**Q WOULD YOU AGREE THAT CUSTOMER ELECTRICAL DEMAND IS AN IMPORTANT CRITERION WHEN DESIGNING A DISTRIBUTION SYSTEM?**

A Yes, I would. Distribution engineers rely on load forecasts and load flow studies to identify and design distribution system upgrades or to project load growth. Peak demand is a vital component of these forecasts and studies. Further, some segments of the delivery system (but not all) will vary with expected demand. However, when developing a COSS, other criteria can be important as well.

[5]That is, the costs increase with the number of customers rather than with customer demand.

[6]I performed exactly this type of study on multiple occasions in my previous employment with Aquila, Inc. See Appendix A for more information.

**Q PLEASE EXPLAIN WHAT YOU MEAN.**

A As I suggested previously, the fundamental premise of a proper COSS is the concept of *cost-causation* which is, in many cases, directly related to electrical parameters like voltage level or peak demand. This is particularly true when planning for maximum conditions or "worst case" scenarios. Yet, there are factors besides voltage level and peak demand that can significantly affect cost. A properly conducted COSS must consider all cost causing factors.

When distribution engineers *design* the enhancement, upgrade, or extension of an electric system, they must be constantly aware of the operating parameters of the system. But, it is in the construction of the distribution system that the *true cause* of many distribution costs is clearly seen. Surprisingly, that cause is frequently *not* demand.

An illustration helps make this point clear. Consider a customer who intends to build a home on a new lot, one that does not already have electrical service. This customer is cost and energy conscious and thus chooses to use as many energy efficiency techniques and appliances as they can. After considerable research and consultation with experts, the customer calls the utility and informs it that he will require service capable of providing a maximum peak demand of 2,000 watts (2 kW).[7]

During the installation of the primary and secondary distribution extension to the customer's home, he notices that the linemen are using conductors, poles, cross-arms, and components identical to those serving the much larger, and less efficient, home down the street. After more investigation, the customer learns that the distribution extension to his home is capable of carrying far greater demand than it was designed to use. When he informs the utility of this 'error,' the utility explains that

[7]This is about two-thirds of the peak demand of a typical residential customer.

it cannot install wires smaller than a certain size or hang them below a certain height. In short, there are specified minimum standards that the utility must meet that are wholly unrelated to the new home's reduced demand.

This illustration demonstrates that although utilities design and install distribution equipment to satisfy their customers' need for electricity, there are factors other than electrical demand that force them to incur costs. Safety and reliability are as critical to every phase of design and construction as demand. As one reviews the cost of the distribution system nearest the customer (that portion from the primary radial lines through the line transformers and secondary system), the cost incurred to comply with safety and reliability standards begins to outweigh the cost of meeting electrical demand.

Nearly every major primary and secondary distribution component (FERC Accounts 364 through 367) must conform to standards set forth in the NESC.[8] In conforming to the Code, the Company incurs costs in direct proportion to the number of poles, cross-arms, feet of wire installed, etc.

If the demand of existing customers increases, the cost of meeting the NESC standards remains fixed. In other words, the cost of meeting the Code for a customer with a peak demand of 3 kW, is exactly the same as that for a customer with a peak demand of 150 kW, or even 1 MW.[9] Conversely, whenever an *extension* of the primary and/or secondary system is constructed, the Company must construct the extension to conform to the minimum standards and will incur additional minimum system costs. Given that the principal reason to extend the distribution system is to

[8]In the case of Conduit (FERC Account 366), the National Electric Code ("NEC") is the governing standard.

[9]The NESC specifies clearances of lines by voltage level. Thus, lines at higher voltages may require taller poles and longer cross-arms.

serve additional customers, it is only reasonable to conclude that the costs associated with the MDS vary with the number of customers.

Conceptually, distribution components that *only just* conform to standards such as the NESC[10] comprise the MDS.

**Q HAS THE ILLINOIS COMMERCE COMMISSION ADOPTED THE NESC STANDARDS IN THE ADMINISTRATIVE CODE?**

A Yes. Title 83 of the Illinois Administrative Code, Part 305, Subsection 305.20b) states:

> "The Illinois Commerce Commission *adopts as its rules the following portions of the National Electrical Safety Code C2-200* (2002 edition, approved June 4, 2001, published by the Institute of Electrical and Electronics Engineers, Inc., 3 Park Avenue, New York NY 10016-5997)…" [Emphasis added.]

**Q WHAT IS THE PURPOSE OF THE NESC?**

A Section 1, Part 010, of the NESC states:

> "The purpose of these rules is the practical safeguarding of persons during the installation, operation, or maintenance of electric supply and communication lines and their associated equipment. They contain *minimum provisions considered necessary* for the safety of employees and the public. They are not intended as a design specification or an instruction manual." [Emphasis added.]

[10]While I limit my discussion to the NESC, there are other standards with which the Company must comply.

**Q IS IT POSSIBLE THAT SOME OF THE COMPANY'S EXISTING DISTRIBUTION SYSTEM COMPONENTS WERE DESIGNED AND INSTALLED PRIOR TO THE NESC – THAT THEY ARE, IN EFFECT, "GRANDFATHERED," AND NOT COVERED BY THE NESC?**

A It is possible, but unlikely. Congress authorized the National Bureau of Standards ("NBS") to study hazards of electrical practice in 1913. In 1915, the NBS published Circular No. 34 titled "Proposed NESC," and published the very first edition of the NESC as NBS handbooks in 1920.[11] Except in extremely rare cases, it is unlikely there are lines, poles, and equipment that pre-date these standards. Even in those extreme cases, though, the costs of the components certainly will be depreciated by now, and have no bearing on the COSS.

**Q DOES THE NESC ALSO ESTABLISH STANDARDS FOR THE ELECTRICAL DEMAND EACH COMPONENT MUST BE CAPABLE OF CARRYING?**

A Not directly. To my knowledge, the only situation where the NESC covers something like this is in the case of grounding wires where the NESC sets the "short time ampacity adequate for a fault current."[12] Yet even here, the purpose of the grounding wire is to provide safety or enhance reliability rather than to serve electrical load.

With that said, it is important to understand that if a distribution system was constructed to *only just* conform to the NESC, it would be capable of carrying the demand of many of the customers on the system. A detailed discussion of the electrical demand of conductors conforming to the NESC is given in IIEC Exhibit 4.2.

[11]The Institute of Electrical and Electronic Engineers ("IEEE") was designated as Administrative Secretariat for the NESC (replacing NBS) in 1972 and continues in that role today.

[12]Section 9, Subsection 93.C., Ampacity and Strength.

**Q PLEASE SUMMARIZE THE DISCUSSION IN IIEC EXHIBIT 4.2.**

A IIEC Exhibit 4.2 discusses specific NESC standards that affect conductor strength and size. Specifically, IIEC Exhibit 4.2 demonstrates that the NESC requires that the typical service drop, secondary, or primary distribution wires be at least a #6 American Wire Gauge ("AWG"). The exhibit also shows that typical distribution wires are capable of serving the peak demand of nearly eight residential customers at standard secondary voltages, and over 235 residential customers at typical primary voltages.

The unmistakable conclusion is that by setting minimum safety and reliability standards, the NESC consequently dictates that primary and secondary distribution lines will be capable of serving the peak demand of many, if not all, of the customers being served by the distribution lines.

**Q SINCE THE MINIMUM CONDUCTOR SIZE SPECIFIED BY THE NESC IS CAPABLE OF SERVING SUCH A HIGH DEMAND, SHOULD THE COST OF THE MDS BE CLASSIFIED AS DEMAND-RELATED?**

A No. Again, the question is not one of wire capacity, but of *cost-causation*. The Commission has adopted, and enforces compliance with, the NESC standards. The NESC requires that conductors be a minimum size. Under these constraints, a utility that extends service to an additional customer must incur the cost of building, at a minimum, to the NESC standards. The *cause* of this minimum sized system cost is the NESC, and is incurred regardless of the customer's demand.

To a cost analyst, the classic indications of a customer-related cost are: (1) constant regardless of customer's electrical demand except in the extreme; (2) directly proportional to the number of customers; or (3) incurred either by the

direct requirement of an ordinance, standard, or bylaw, at the request of a customer, or for the sole benefit of a customer. Whenever utilities install or replace distribution facilities, or construct an extension to a distribution line, the cost incurred to conform to the NESC matches all three of these criteria perfectly.

**Q ARE DISTRIBUTION COSTS INCURRED TO MEET THE AVERAGE DEMAND OF CUSTOMERS?**

A No. While the distribution system must serve the daily, or average, demand of customers throughout the year, doing so does not influence the distribution system's cost. This is easily demonstrated using a simple example.

Consider a portion of a distribution system serving 100 customers through a network of 25 secondary lines connected to a single-phase primary line operating at 12 kV. Referring to IIEC Exhibit 4.2, it can be shown that the secondary system described by this example, if constructed to only just conform to the NESC standards, is capable of carrying just over 510 kW. Similarly, the primary line, if constructed to only just conform to the NESC, is capable of serving nearly 700 kW.

With this system in mind, consider three possible scenarios: (1) the combined peak demand of the 100 customers is less than 500 kW; (2) the combined peak demand is greater than 700 kW; and (3) the average demand of the 100 customers is 750 kW.

In the first scenario, the combined peak demand of the 100 customers is less than the capacity of the secondary and primary systems. In this scenario, the secondary and primary systems were built to conform to the Code regardless of the peak demand of the customer. Thus, the minimum system standards caused these costs to be incurred.

In the second scenario, the combined peak demand of the 100 customers is greater than the capacity of either the secondary or primary systems. Obviously, the utility will need to upgrade the systems by installing larger primary conductors, and adding more and/or larger secondary lines. In doing so, the utility's distribution engineers will estimate the peak demand this section of the distribution system will experience in the foreseeable future, and design the upgrades accordingly. For the purpose of illustration, suppose the upgraded primary and secondary system is capable of carrying 1,500 kW.

Two factors combine to cause the total cost of the upgraded system. First, the minimum system standards continue to account for the minimum costs just as they did before the upgrade, but there are now additional costs incurred to meet the anticipated peak demand. Stated another way, the minimum standards are responsible for the minimum system costs, and the peak demand values are responsible for the additional costs above those of the minimum system.

In the final scenario, the average demand of the 100 customers is greater than 750 kW. This demand is larger than the capacity of the minimum system required by the NESC, but less than the capacity of the upgraded system.

In this scenario, the utility will not need to upgrade the system or add components so no additional costs will be incurred. The two factors contributing to the cost of the system in this scenario are identical to the previous scenario. It is reasonable to conclude that the average demand placed on the system by the customers does not influence the cost of the distribution system.

**Q HOW HAS AMEREN CLASSIFIED AND ALLOCATED COSTS IN FERC ACCOUNTS 364 THROUGH 368 IN ITS COSS?**

A Ameren classifies these costs as demand-related and allocates them to the customer classes on the basis of each class's non-coincident peak ("NCP") demand.

**Q DO YOU AGREE WITH THE COMPANY'S CLASSIFICATION AND ALLOCATION OF DISTRIBUTION CONDUCTORS AND POLES?**

A No. Significant portions of the costs in FERC Accounts 364 through 368 are customer-related. Accordingly, those costs should not be allocated on the same basis as demand-related distribution system costs. Tables 1, 2, and 3 show the demand and customer allocation factors for each of the secondary and primary voltage classes of Ameren's Illinois electric territories.

**TABLE 1**

**AmerenCILCO Demand and Customer Allocations**

| | | AmerenCILCO | |
|---|---|---|---|
| **Line** | **Rate Class** | **Demand** | **Customer** |
| 1 | DS1 | 54.0% | 88.7% |
| 2 | DS 2 | 18.5% | 10.9% |
| 3 | DS 3a | 6.8% | 0.3% |
| 4 | DS 3b | 4.6% | 0.1% |
| 5 | DS 4 Sec & Prim | 9.2% | 0.04% |
| 6 | DS 4 High Voltage | 6.3% | 0.00% |
| 7 | DS 4 100+ KV | 0.0% | 0.00% |
| 8 | Total DS 4 | 15.4% | 0.04% |
| 9 | DS 5 | 0.7% | 0.02% |

**TABLE 2**

**AmerenCIPS Demand and Customer Allocations**

| Line | Rate Class | AmerenCIPS Demand | AmerenCIPS Customer |
|---|---|---|---|
| 1 | DS1 | 48.1% | 85.7% |
| 2 | DS 2 | 19.2% | 13.8% |
| 3 | DS 3a | 5.6% | 0.3% |
| 4 | DS 3b | 5.4% | 0.1% |
| 5 | DS 4 Sec & Prim | 8.8% | 0.05% |
| 6 | DS 4 High Voltage | 11.9% | 0.00% |
| 7 | DS 4 100+ KV | 0.0% | 0.00% |
| 8 | Total DS 4 | 20.7% | 0.05% |
| 9 | DS 5 | 1.1% | 0.04% |

**TABLE 3**

**AmerenIP Demand and Customer Allocations**

| Line | Rate Class | AmerenIP Demand | AmerenIP Customer |
|---|---|---|---|
| 1 | DS1 | 50.8% | 88.0% |
| 2 | DS 2 | 17.0% | 11.4% |
| 3 | DS 3a | 4.7% | 0.2% |
| 4 | DS 3b | 5.3% | 0.1% |
| 5 | DS 4 Sec & Prim | 3.2% | 0.03% |
| 6 | DS 4 High Voltage | 17.5% | 0.01% |
| 7 | DS 4 100+ KV | 0.0% | 0.00% |
| 8 | Total DS 4 | 20.8% | 0.04% |
| 9 | DS 5 | 1.3% | 0.3% |

Tables 1, 2 and 3 show that the demand allocation factor is significantly higher than the customer allocation factor for DS-2, DS-3, and DS-4 customers.

For example, the demand allocation percentages for DS-4 secondary and primary are 9.2%, 8.8%, and 3.2% for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively. In contrast to this, the customer allocation percentages for this same class of customers are 0.04%, 0.05%, and 0.03% for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively. If $10,000,000 in customer-related distribution costs

were allocated using Ameren's method, the DS-4 secondary and primary customers would be allocated $920,000, $880,000, or $320,000, for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively. If these costs were distributed using the customer allocation factor, these customers would be allocated less than $4,000 if served by AmerenCILCO, $5,000 if served by AmerenCIPS, and $3,000 if served by AmerenIP.

**Q WHAT PROBLEMS ARISE FROM ALLOCATING COSTS USING THE WRONG FACTOR?**

A The most obvious problem is that the rates will no longer be based on cost-causation, and therefore will suffer the deficiencies inherent in that misallocation, which were discussed earlier in my testimony (*viz*., inequity, inappropriate price signals, detriments to conservation, and revenue instability). Rates developed from a COSS that improperly allocates costs will create, or exacerbate, inter- and intra-class subsidies.

## Effect of MDS Methods on Rates

**Q HOW DOES THE USE OF MDS METHODS AFFECT THE CUSTOMER RATES IN THIS CASE?**

A In general, using MDS methods provide analysts a closer look at the cause of certain costs, allowing them to better align rates with cost-causation principles. MDS methods result in a smaller allocation of distribution costs to classes with fewer customers (e.g., Large Industrial customers), and a larger allocation of distribution costs to classes with more customers (e.g., Residential customers).

**Q DOES THE USE OF MDS METHODS RESULT IN AN UNFAIR ALLOCATION OF COSTS?**

A No. Since these methods adhere to cost-causation principles, their use allocates costs to customer classes that cause the Company to incur them. In short, accounting for the cost of meeting minimum safety and reliability standards results in a better COSS than one that denies the MDS exists.

**Q WOULD THE USE OF MDS METHODS RESULT IN A DOUBLE ALLOCATION OF DEMAND COSTS?**

A No. This has been a common argument against the MDS methods, but one that errs in at least two ways. First, the processes of functionalization and cost classification separate and distinguish costs from each other *preventing* the double allocation of costs to customers.[13] This occurs regardless of the use of minimum distribution methods. When costs are classified as customer- or demand-related, they are isolated from each other, and are distributed to the classes only once.

Second, the double allocation argument stems from a notion that electrical demand can be accumulated in much the same manner as costs. The argument is this: if a distribution component is classified as customer-related, yet is capable of carrying a demand, that amount of demand must always be associated with its customer-related costs, and kept separate from the remainder of the system's demand. If this is not done, or so the argument alleges, there will be a double allocation of demand-related costs.

The problem with this argument is that electrical demands cannot be accumulated in the same manner as costs. For example, using the same

[13]See IIEC Exhibit 4.1 for an illustration of these processes.

hypothetical community of 100 customers described earlier, consider again the third scenario pertaining to the average demand of the 100 customers. In that scenario, the average demand was said to be 750 kW. This is the sum of the demand values measured by the customer meters. However, except for a very small loss factor, this is also the total of the demands flowing through the services. And again, except for another small loss factor, this is the sum of the demands flowing though the secondary lines, the transformers, and the primary line. One cannot simply add the demands passing through the meters (750 kW), services (≈ 750 kW), secondary lines (≈ 750 kW), and so on to find the total demand of the system. Likewise, one cannot subtract the demand passing through one component from the total demand flowing across the distribution system.

In light of this, it is illogical to suggest that the demand passing through one component must be subtracted and kept separate from the total whenever the component is classified as customer-related. This is also inconsistent with the way costs are normally classified and allocated.

**Q PLEASE EXPLAIN WHAT YOU MEAN.**

A There is little controversy among cost analysts regarding the allocation of the cost of meters and services. The costs of these components are classified as customer-related because they meet the three criteria of customer-related costs. Accordingly, these costs are distributed using a weighted customer allocation factor. Yet, meters and service drops also carry significant demand. For each of Ameren's electric territories, the sum of the demands passing through the meters alone is approximately 95% of the total demand delivered by the transmission system. The same is true for the demands passing through service drops.

It would be unreasonable and unprecedented to subtract the demand passing through meters or services from the total system demand, and claim that this is necessary to prevent the double allocation of costs to a particular class of customer.

## Methods for Determining MDS Costs

**Q HOW ARE THE COSTS OF CONFORMING TO THE MINIMUM STANDARDS CALCULATED?**

A This is precisely what the MDS techniques were developed to determine, and it is not surprising that they are given names such as *minimum system* and *minimum or zero intercept*. Every method compares the replacement cost of each major component (i.e., poles, overhead conductors, etc.) to the replacement cost of each component if it were of the minimum size to only just conform to the NESC or other applicable safety and reliability standard.

**Q HOW DO THESE TECHNIQUES DIFFER FROM EACH OTHER?**

A While all the methods attempt to calculate the cost of the MDS, they differ in how they go about it. The zero intercept methods calculate the cost of the minimum sized components using *theoretical* components, whereas the minimum system methods use *actual* components available on the market.

**Q YOU USE THE PLURAL FORM OF THE WORD 'METHODS' WHEN SPEAKING OF EITHER THE ZERO INTERCEPT OR THE MINIMUM SYSTEM. ARE THERE VARIATIONS EVEN WITHIN THESE METHODS?**

A Yes. I am aware of two variations of the minimum system method, and two variations of the zero intercept method.

**Q WHAT ARE THE VARIATIONS OF THE MINIMUM SYSTEM METHOD?**

A One variation relies on distribution components that a utility *normally purchases or has in inventory*. If, for example, the utility were to calculate the minimum system costs for Account 364 (Poles) using this variation, for example, it would use the shortest pole in its inventory – provided it conformed to the NESC -- even if a smaller and/or less expensive pole were available on the market.

For example, if a utility only purchased utility poles that were 30 feet or more in length, it would define the minimum length of pole as 30 feet, even though 25-foot poles are readily available on the market.

The second variation of the minimum system method relies on components that are available on the market, regardless of *whether the company uses such components*. Using this method, the hypothetical utility mentioned above would define the minimum length of pole as 25 feet, even though it does not purchase poles of that length.[14]

The advantage to both methods is that they use data that are readily available to the analyst. They provide a way to quickly estimate minimum system costs, and allow the cost analyst to do more than arbitrarily classify some, all, or none of the distribution costs to demand- or customer-related.

**Q WHAT ARE THE VARIATIONS ON THE ZERO INTERCEPT METHOD?**

A The zero intercept methods attempt to calculate the cost of the minimum system that either: (1) only just conforms to the NESC standards; or (2) has reduced the demand cost to zero. Both are theoretical values calculated using statistical methods.

[14]Obviously, poles are only one example of MDS components, but they illustrate the concept.

However, the zero intercept methods are considered by many analysts to be the most accurate methods to use in estimating the customer portion of distribution costs.[15]

**Q IS THERE A PREFERRED MDS METHOD?**

A If the options are: (1) to perform a minimum distribution study that calculates the customer and demand percentages; or (2) to assign distribution accounts significantly affected by safety and reliability standards entirely to demand, as was done by the Company in this case, then the preferred method would be to perform a study.

The evidence that a MDS exists and that its cost is a significant percentage of the total distribution cost is simply too clear and compelling to ignore. However, by classifying the cost of poles, conductors, transformers, and conduit the way it has, the Company ignores the evidence. It would be far better to perform a minimum distribution study so that the COSS can truly reflect cost-causation principles and provide better information upon which to design the Company's rates.

In a perfect world, where the necessary data were available and time was allowed for a thorough study, the preferred method would be to perform the *minimum system* study using commercially available components that *only just* conform to the NESC. If a component of the precise size is not commercially available – as may well happen in the case of FERC Account 364 (Poles) – it would be preferable to use the zero intercept technique to determine the cost of the *theoretical* component that only just conforms to the NESC.

[15]National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual ("NARUC Manual"), Chapter 6, Section II.B., page 92.

**Q IS THE COMPANY'S COSS CAPABLE OF ALLOCATING MDS COSTS TO CUSTOMER CLASSES PROPERLY?**

A Yes. The Company's COSS, in the form provided in discovery, allows for the allocation of MDS costs with only a few simple adjustments.

**Q HAVE YOU PERFORMED A PRECISE ANALYSIS OF AMEREN'S DISTRIBUTION COSTS USING YOUR PREFERRED METHOD?**

A No. The discovery process in this case did not afford the necessary information and time for me to conduct a complete study. In the absence of a precise MDS study, I relied on customer and demand percentages that were provided by the Company as part of its 2006 COSS for its Missouri subsidiary "AmerenUE",[16] as well as values from MDS studies that I personally performed on utilities in Missouri, Kansas, and Colorado with distribution facilities and service territories similar to those of AmerenCILCO, AmerenCIPS, and AmerenIP.

**Q HOW ARE THE SERVICE TERRITORIES AND DISTRIBUTION FACILITIES OF THE MISSOURI, KANSAS, AND COLORADO UTILITIES SIMILAR TO THE AMEREN COMPANIES?**

A The communities served by the utilities in Missouri, Kansas, and Colorado are a mixture of rural, suburban, and urban comparable to the communities served by AmerenCILCO, AmerenCIPS, and AmerenIP. Also, the total investment in rate base made by the Missouri, Kansas, and Colorado utilities ranged from $100 million to nearly a $1.5 billion. The rate base investment by the Ameren companies ranges from $300 million to nearly $1.5 billion. Finally, the average mix of primary and

[16] Missouri Public Service Commission, Case No. ER-2007-0002

secondary distribution, as a percentage of total distribution plant, of the Missouri, Kansas, and Colorado utilities is comparable to the Ameren companies.

## Review of Ameren's Cost Studies

**Q HAVE YOU REVIEWED THE RESULTS OF AMEREN'S COSS?**

A Yes, I reviewed the results of the Company's embedded COSS for the test year ending December 31, 2006. The results show that, overall, the revenue recovered through the existing rates is adequate to meet the Company's expenses plus provide a 6.9%, 4.7%, and 2.7% return on rate base for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively.

These results, which I discuss below, are premised on Ameren's COSS model, and are entirely dependent on the inputs and assumptions that go into the model. Obviously, the results are only as accurate and valid as the assumptions and inputs upon which the COSS models are built.

I discuss the COSS and results for each of Ameren's three Illinois utilities below.

**Q HAVE YOU ALSO MODIFIED THE AMERENCILCO, AMERENCIPS, AND AMERENIP COST OF SERVICE STUDIES TO ALLOCATE CUSTOMER- AND DEMAND-RELATED COSTS BASED ON MDS PRINCIPLES?**

A Yes. The three Ameren studies are deficient in that they do not recognize the cost impact of the minimum distribution system. My changes allow for the separation of customer- and demand-related costs.

**Q PLEASE DESCRIBE YOUR MODIFICATIONS.**

A Each of the three studies was modified to allow for the proper allocation of MDS costs. Under my direct supervision, the COSS model was modified to accumulate customer and demand costs for FERC Accounts 364 through 367. Also, new demand and customer allocation factors were calculated and added to each COSS. This step did not require additional programming since the original COSS contained a work space specifically designed for new allocation factors.

**Q WHAT CUSTOMER AND DEMAND PERCENTAGES DID YOU USE?**

A The following customer and demand percentages were used: (1) for FERC Account 364 (Poles), 84% demand and 16% customer; (2) for FERC Account 365 (Overhead Wires), 85% demand and 15% customer; (3) for FERC Account 366 (Conduit), 39% demand and 61% customer; and (4) for FERC Account 367 (Underground Conductor), 26% demand and 74% customer.

**Q WHAT DATA DID YOU RELY UPON TO DETERMINE THESE PERCENTAGES?**

A As I discussed previously, the MDS is the system that conforms to safety and reliability standards such as the NESC. These standards apply equally to nearly every electric utility in the nation, so it is reasonable to assume that the standards required by the NESC in one territory are exactly the same as those required in every other service territory. Based upon this fact, and coupled with the results of an MDS study performed by Ameren for its Missouri company, and upon my experience in performing MDS studies on other utilities operating in Missouri, Kansas, and Colorado, I chose customer and demand percentages that were within the range of those determined for utilities with urban operations, suburban operations, and rural

operations similar to those within the Ameren territories. Specifically, I averaged the customer and demand percentages for five electric companies as shown in Table 4. I then used these average percentages in the modified COSS.

**TABLE 4**

**Customer and Demand Percentages Recognizing MDS**

| Line | Company | Classification | FERC Accounts 364 | 365 | 366 | 367 |
|---|---|---|---|---|---|---|
| 1 | AmerenUE - 2006 COS | Demand | 88% | 72% | 94% | 79% |
| 2 | | Customer | 12% | 28% | 6% | 21% |
| 3 | Aquila Networks - MPS | Demand | 75% | 90% | 25% | 13% |
| 4 | | Customer | 25% | 10% | 75% | 87% |
| 5 | Aquila Networks - L&P | Demand | 86% | 90% | 37% | 16% |
| 6 | | Customer | 14% | 10% | 63% | 84% |
| 7 | Aquila Networks - WPK | Demand | 89% | 85% | 18% | 9% |
| 8 | | Customer | 11% | 15% | 82% | 91% |
| 9 | Aquila Networks - WPC | Demand | 83% | 85% | 19% | 14% |
| 10 | | Customer | 17% | 15% | 81% | 86% |
| 11 | | Avg Demand | 84% | 85% | 39% | 26% |
| 12 | | Avg Customer | 16% | 15% | 61% | 74% |

While this is a reasonable approach, if the Company can document the actual customer and demand percentages, it would be reasonable to use the Company's actual percentages rather than my estimates.

## Results of AmerenCILCO's COSS

**Q WHAT ARE THE RESULTS OF AMERENCILCO'S COSS?**

A The results of the Company's COSS are shown in Table 5.

**TABLE 5**

**AmerenCILCO - Rate of Return - As Filed**

| Line | Rate Class | Rate of Return | Reqd Increase |
|---|---|---|---|
| 1 | DS 1 (Residential) | 5.7% | 14.2% |
| 2 | DS 2 | 9.7% | -3.4% |
| 3 | DS 3 | 12.5% | -14.5% |
| 4 | DS 4 - Secondary | -6.3% | 3725.9% |
| 5 | DS 4 - Primary | 3.0% | 35.9% |
| 6 | DS 4 - High Voltage | 24.6% | -41.2% |
| 7 | DS 4 - 100+ kV | NM | -96.0% |
| 8 | Total DS 4 | 5.3% | 21.0% |
| 9 | DS 5 | 5.8% | 10.0% |
| 10 | AmerenCILCO Total | 6.9% | 8.6% |

**Q WHAT DOES TABLE 5 SHOW?**

A Table 5 is a brief excerpt from IIEC Exhibit 4.3 and shows the class return on rate base ("ROR") and revenue allocation at the Equal Percent of Embedded Cost ("EPEC").[17]

The first column shows percentage values that are the net operating income ("NOI") for each class divided by the rate base allocated to the class in the COSS. The data show that, overall, the revenue recovered through the existing rates is adequate to meet the Company's expenses plus provide a 6.9% ROR, but that the ROR from individual classes varies widely. To the extent that the COSS is designed to properly recognize the relevant cost-causation factors, individual classes with an ROR greater than 6.9% subsidize classes with an ROR less than 6.9%

[17]The EPEC method gradually equalizes rates of return by allocating the total revenue requirement on a cost of service basis.

The second column shows the allocation of revenue requirement to each class as a percentage of the total company revenue requirement calculated by the COSS. Line 10 shows the percentage increase in revenue requirement for AmerenCILCO as a whole based on an EPEC of 8.85% and accounting for taxes. The data in this column suggest that if rates were designed to reflect the cost of service, AmerenCILCO would receive an overall revenue increase of 8.6%.

**Q HAVE YOU PERFORMED OTHER ANALYSES ON AMERENCILCO'S COSS?**

A Yes. Since the total company ROR of 6.9% is an average value, I performed an additional study to determine the Net Operating Income ("NOI") from each class as if its ROR was exactly the same as the company average. I then calculated the difference between this new NOI value and the class's NOI under present rates as determined by the COSS.

Also, since the Company has proposed to raise the rates of every customer class by an equal percentage, I performed a similar analysis to show the subsidy given or received by each customer class were the Commission to grant Ameren's request.

**Q PLEASE DESCRIBE THE STEPS OF THIS ANALYSIS?**

A I began with the COSS filed by AmerenCILCO, which included the "claimed" or target return on rate base of 8.85%, and using this I calculated the revenue required from each class to bring it to the EPEC. I then determined the AmerenCILCO total revenue requirement increase to be 8.6% above the total company sales revenue at present rates.

I recorded the sales revenue at present rates ("$REV_{SALES}$") for each class as provided by AmerenCILCO, and also the increase or decrease in class revenue required to bring each class to the EPEC ("$RevIncr_{EPEC}$"). Since AmerenCILCO has proposed to raise the rates of every class by the average company revenue increase of 8.6%, I determined the proposed revenue increase ("$RevIncr_{PROPOSED}$") for each class by multiplying the $REV_{SALES}$ for each class by 8.6%.

$$REV_{SALES} \times 8.6\% = RevIncr_{PROPOSED}$$

I calculated the subsidy for each class as the difference between $RevIncr_{PROPOSED}$ and $RevIncr_{EPEC}$.

**Q WHAT ARE THE RESULTS OF THESE ANALYSES?**

A The results are shown in Figure 1.

**Figure 1: AmerenCILCO's Class Subsidy at Present Rates and Proposed Revenue Allocation**

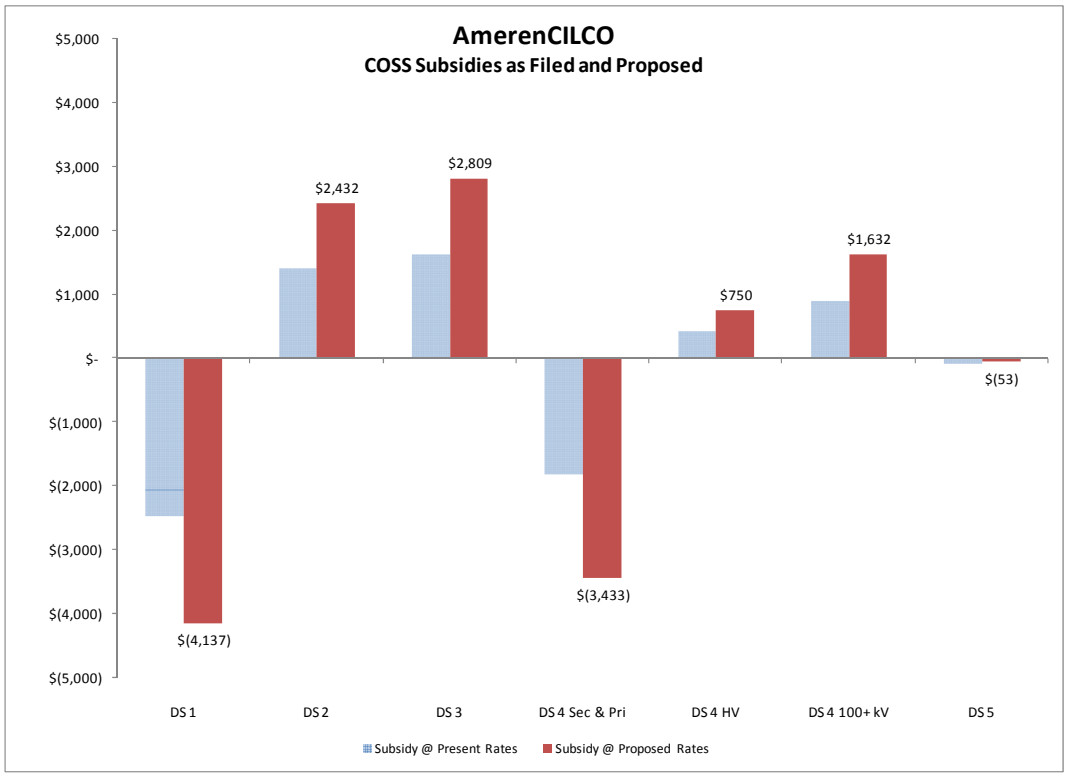


Figure 1 shows that, according to the AmerenCILCO COSS, two classes (DS-1 and DS-4 secondary and primary) receive a significant subsidy from the other classes. The figure also shows that increasing the rates of every class as Ameren has proposed will exacerbate the subsidies given or received.

**Q HAVE YOU MODIFIED THE AMERENCILCO STUDY TO INCORPORATE THE MDS PRINCIPLES AS YOU SUGGESTED ABOVE.?**

A Yes I have.

**Q WHAT EFFECT DO YOUR MODIFICATIONS HAVE ON THE RESULTS OF THE COSS?**

A I've summarized the results from the modified COSS, and compare these results with the Company's proposal in Table 6.

**TABLE 6**

**AmerenCILCO Proposal vs. IIEC Proposal with Modified COSS**

| | | AmerenCILCO | | Modified COSS | |
|---|---|---|---|---|---|
| Line | Rate Class | Rate of Return | Proposed Increase | Rate of Return | Reqd Increase |
| 1 | DS 1 (Residential) | 5.7% | 8.6% | 4.4% | 21.7% |
| 2 | DS 2 | 9.7% | 8.6% | 11.2% | -9.3% |
| 3 | DS 3 | 12.5% | 8.6% | 19.7% | -33.3% |
| 4 | DS 4 - Sec & Pri | 0.4% | 8.6% | 3.4% | 37.1% |
| 5 | DS 4 - High Voltage | 24.6% | 8.6% | 24.6% | -41.1% |
| 6 | DS 4 - 100+ kV | NM | 8.6% | NM | -95.9% |
| 7 | Total DS 4 | 5.3% | 8.6% | 9.1% | -1.4% |
| 8 | DS 5 | 5.8% | 8.6% | 7.3% | 4.7% |
| 9 | AmerenCILCO Total | 6.9% | 8.6% | 6.9% | 8.6% |

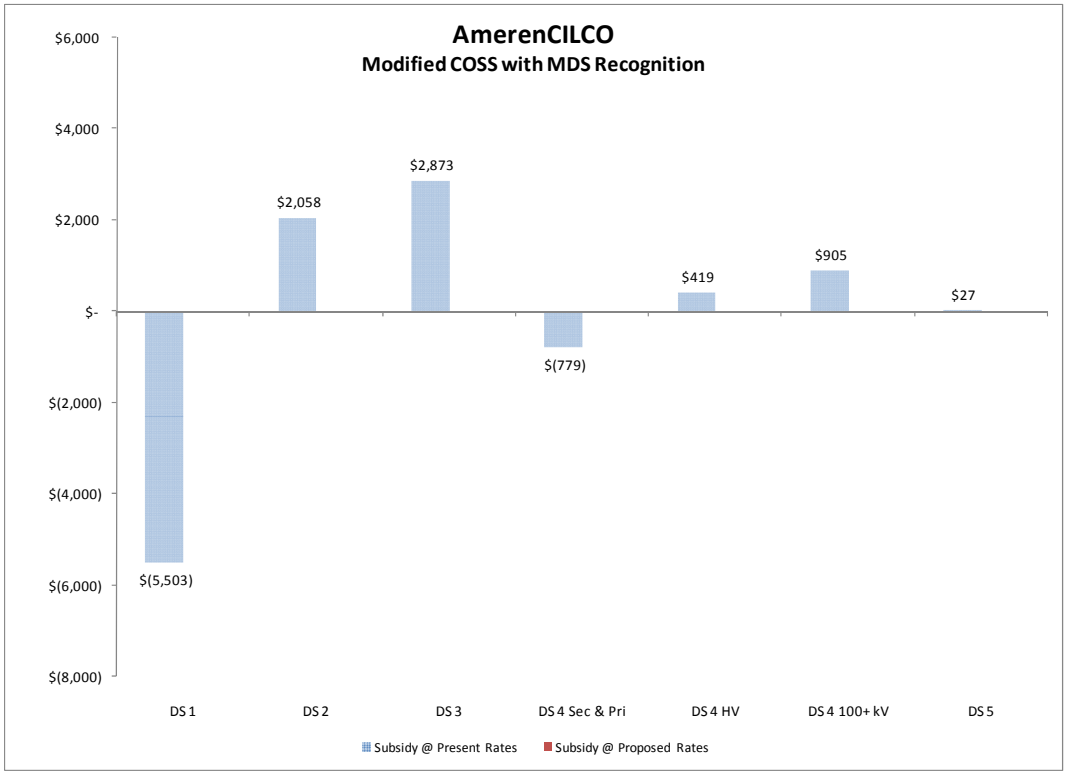
**Q PLEASE DESCRIBE WHAT TABLE 6 SHOWS.**

A Table 6 shows that the modifications to AmerenCILCO's COSS to recognize MDS have negligible impact on the overall company ROR at present rates, or the total increase in revenue needed to achieve the target ROR. However, the impact on the ROR and revenue allocation of individual rate classes is significant. In general, cost and rate base responsibility was shifted from classes with relatively few numbers of customers to classes with relatively large numbers of customers.

In certain cases, the data provided by Ameren were grossly distorted, indicating rates of return greater than 700%. The cause of these extreme values stems from fact that these classes contain very few, if any, customers, and also that slight variations in revenue received from, or costs allocated to, these classes have a significant impact on the return percentage of the class. In these cases, the letters "NM" were used to indicate that the data was "not meaningful."

This shift in cost and rate base responsibility was expected because the original COSS for AmerenCILCO allocated all of the costs from FERC Accounts 364 through 367 on the basis of demand, whereas recognizing the MDS allocated the costs incurred to conform to the NESC on the basis of customer numbers. MDS recognition within the COSS provides a clearer, more accurate picture of the subsidies to individual classes under present rates as shown in Figure 2.

**Figure 2: AmerenCILCO's Class Subsidies:
Modified COSS and Revenue Allocation at Cost of Service**




**Q WHY DOES FIGURE 2 SHOW ONLY A SINGLE DATA SET INDICATING SUBSIDIES AT PRESENT RATES?**

A This is the expected result. The COSS is used to determine the revenue requirement of each class to bring them to cost of service. If revenue increases are not recovered as predicted by the COSS, subsidies will occur. Figure 2 was developed under the assumption that the revenue requirement increases would equal those determined by the COSS. This, by definition, eliminated subsidies arising from the resulting rates.

## Results of AmerenCIPS' COSS

**Q WHAT ARE THE RESULTS OF AMERENCIPS' COSS?**

A The results of the Company's COSS are shown in Table 7.

**TABLE 7**

**AmerenCIPS - Rate of Return - As Filed**

| Line | Rate Class | Rate of Return | Reqd Increase |
|---|---|---|---|
| 1 | DS 1 (Residential) | 2.9% | 23.9% |
| 2 | DS 2 | 9.1% | -1.3% |
| 3 | DS 3 | 9.4% | -2.4% |
| 4 | DS 4 - Secondary | -8.2% | 509.1% |
| 5 | DS 4 - Primary | 1.7% | 35.2% |
| 6 | DS 4 - High Voltage | 7.8% | 3.3% |
| 7 | DS 4 - 100+ kV | NM | -99.8% |
| 8 | Total DS 4 | 2.8% | 29.4% |
| 9 | DS 5 | 5.7% | 6.9% |
| 10 | AmerenCIPS Total | 4.7% | 15.7% |

**Q WHAT DOES TABLE 7 SHOW?**

A Table 7 is an excerpt from IIEC Exhibit 4.3 and shows the class rate of return at present rates and the revenue allocation at the EPEC.

The first column shows percentage values that are the NOI for each class divided by the rate base allocated to the class in the COSS. The data show that, overall, the revenue recovered through the existing rates is adequate to meet the Company's expenses plus provide a 4.7% ROR, but that the ROR from individual classes varies widely. To the extent that the COSS is designed to properly recognize the relevant cost-causation factors, individual classes with an ROR greater than 4.7% subsidize classes with an ROR less than 4.7%

The second column shows the allocation of revenue to each class as a percentage of the total company revenue requirement calculated by the COSS. Line 10 shows the percentage increase in revenue requirement for AmerenCIPS as a whole based on an EPEC of 8.73% and accounting for taxes. The data in this column suggest that if rates were designed to reflect the cost of service, AmerenCIPS would receive an overall increase of 15.7%.

**Q HAVE YOU PERFORMED OTHER ANALYSES ON AMERENCIPS' COSS?**

A Yes. Since the total company ROR of 4.7% is an average value, I performed an additional study to determine the NOI from each class as if its ROR was exactly the same as the company average. I then calculated the difference between this NOI value and the class's NOI under present rates as determined by the COSS.

Also, since the Company has proposed to raise the rates of every customer class by an equal percentage, I performed a similar analysis to show the subsidy given or received by each customer class were the Commission to grant Ameren's request.

**Q PLEASE DESCRIBE THE STEPS OF THIS ANALYSIS?**

A I began with the COSS filed by AmerenCIPS, which included a "claimed" or target return on rate base of 8.73%. Using the same process as I have described for AmerenCILCO, I found the total company revenue increase to be 15.7% above the total company sales revenue at present rates. I then calculated the class subsidies, again using the same procedures as described for AmerenCILCO.

**Q WHAT ARE THE RESULTS OF THESE ANALYSES?**

A The results are shown in Figure 3 below.

**Figure 3: AmerenCIPS' Class Subsidies at Present Rates and Proposed Revenue Allocation**

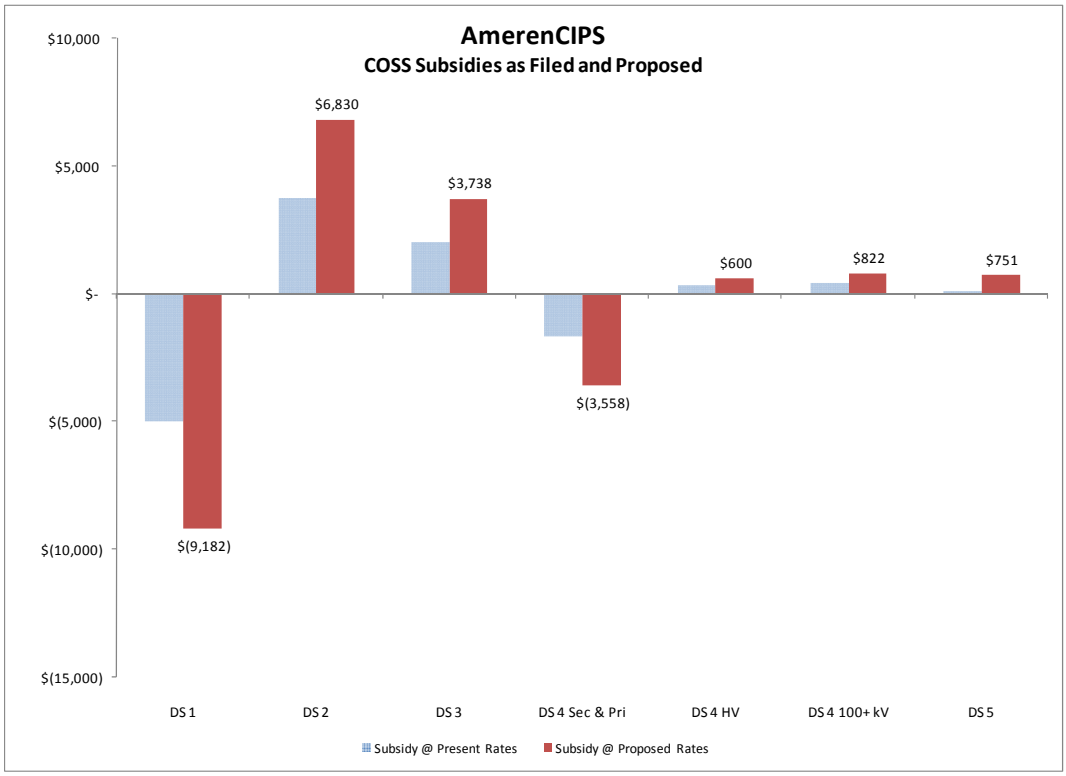



Figure 3 shows that, according to the AmerenCIPS COSS, two classes (DS-1 and DS-4 secondary and primary) receive a subsidy from the other classes. The figure also shows that increasing the rates of every class as Ameren has proposed will exacerbate the subsidies given or received.

**Q HAVE YOU MODIFIED THE COMPANY'S COSS TO ALLOCATE CUSTOMER- AND DEMAND-RELATED COSTS BY INCORPORATING MDS PRINCIPLES?**

A Yes. My changes to the AmerenCIPS COSS are the same as those described for all three studies in my testimony above.

**Q WHAT EFFECT DO YOUR MODIFICATIONS HAVE ON THE RESULTS OF THE COSS?**

A I've summarized the results from the modified COSS in Table 8.

**TABLE 8**

**AmerenCIPS Proposal vs. IIEC Proposal with Modified COSS**

| | | AmerenCIPS | | Modified COSS | |
|---|---|---|---|---|---|
| Line | Rate Class | Rate of Return | Proposed Increase | Rate of Return | Reqd Increase |
| 1 | DS 1 (Residential) | 2.9% | 15.7% | 2.1% | 28.5% |
| 2 | DS 2 | 9.1% | 15.7% | 9.4% | -2.5% |
| 3 | DS 3 | 9.4% | 15.7% | 13.1% | -13.3% |
| 4 | DS 4 - Sec & Pri | 0.0% | 15.7% | 2.5% | 31.6% |
| 5 | DS 4 - High Voltage | 7.8% | 15.7% | 7.8% | 3.3% |
| 6 | DS 4 - 100+ kV | NM | 15.7% | NM | -99.8% |
| 7 | Total DS 4 | 2.8% | 15.7% | 4.9% | 16.8% |
| 8 | DS 5 | 5.7% | 15.7% | 7.8% | 2.0% |
| 9 | AmerenCIPS Total | 4.7% | 15.7% | 4.7% | 15.7% |

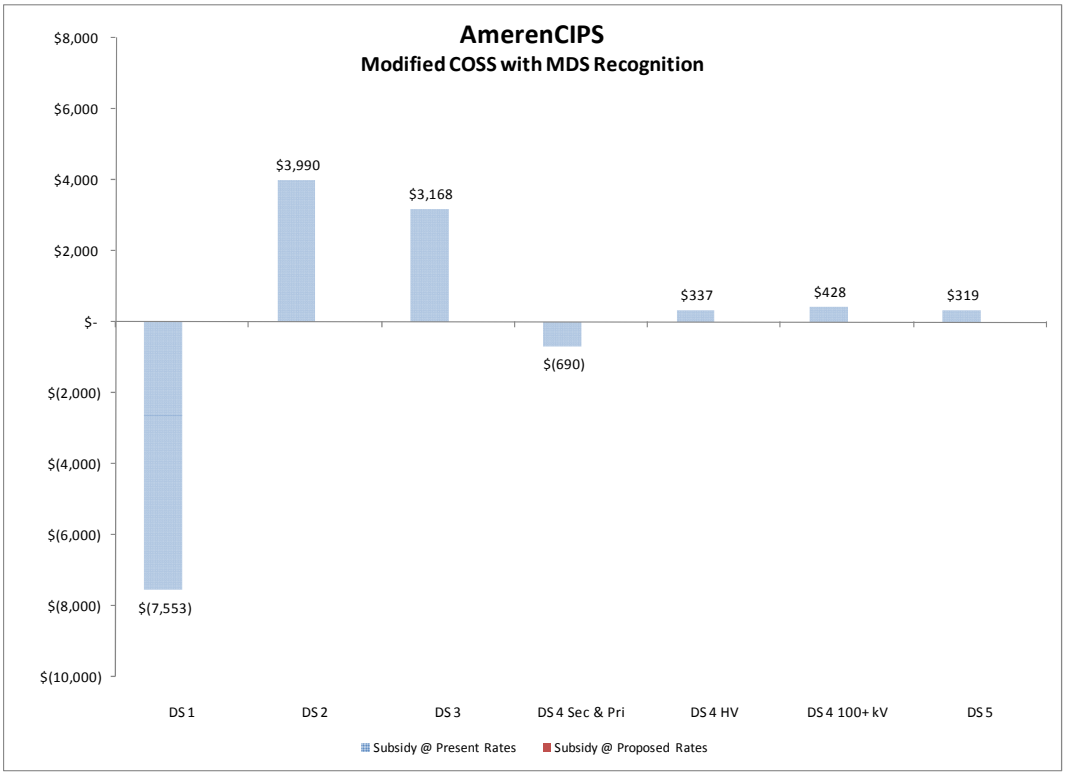
**Q PLEASE DESCRIBE WHAT TABLE 8 SHOWS.**

A Table 8 shows that the modifications to AmerenCIPS' COSS to recognize MDS had little impact on the overall company ROR at present rates, or the total increase in revenue needed to achieve the target ROR. However, the impact on the ROR and revenue allocation of individual rate classes is significant. In general, cost and rate base responsibility was shifted from classes with relatively few numbers of customers to classes with relatively large numbers of customers.

This shift was expected because the Company's original COSS for AmerenCIPS allocated all of the costs from FERC Accounts 364 through 367 on the basis of demand, whereas recognizing the MDS allocated the costs incurred to

conform to the NESC on the basis of customer numbers. MDS recognition within the COSS provides a clearer, more accurate picture of the subsidies to individual classes under present rates as shown in Figure 4.

**Figure 4: AmerenCIPS' Class Subsidies:**
**Modified COSS and Revenue Allocation at Cost of Service**




## Results of AmerenIP's COSS

**Q WHAT ARE THE RESULTS OF AMERENIP'S COSS?**

A The results of the Company's COSS are shown in Table 9.

**TABLE 9**

**AmerenIP - Rate of Return - As Filed**

| Line | Rate Class | Rate of Return | Reqd Increase |
|---|---|---|---|
| 1 | DS 1 (Residential) | 0.7% | 59.3% |
| 2 | DS 2 | 8.0% | 5.2% |
| 3 | DS 3 | 4.6% | 26.4% |
| 4 | DS 4 - Secondary | -5.3% | 1443.7% |
| 5 | DS 4 - Primary | 3.0% | 38.6% |
| 6 | DS 4 - High Voltage | 7.1% | 10.6% |
| 7 | DS 4 - 100+ kV | NM | -40.3% |
| 8 | Total DS 4 | 4.4% | 28.8% |
| 9 | DS 5 | 6.5% | 17.0% |
| 10 | AmerenIP Total | 2.7% | 41.1% |

**Q WHAT DOES TABLE 9 SHOW?**

A Table 9 is an excerpt from IIEC Exhibit 4.3 and shows the class rate of return at present rates and the revenue allocation at an EPEC .

The first column shows percentage values that are the NOI for each class divided by the rate base allocated to the class in the COSS. The data show that, overall, the revenue recovered through the existing rates is adequate to meet the Company's expenses plus provide a 2.7% ROR, but that the ROR from individual classes varies widely. To the extent that the COSS is designed to properly recognize the relevant cost-causation factors, individual classes with an ROR greater than 2.7% subsidize classes with an ROR less than 2.7%

The second column shows the allocation of revenue to each class as a percentage of the total company revenue requirement calculated by the COSS. Line 10 shows the percentage increase in revenue requirement for AmerenIP as a

whole based on an EPEC of 9.02% and accounting for taxes. The data in this column suggest that if rates were designed to reflect the cost of service, AmerenIP would receive an overall increase of 41.1%.

**Q HAVE YOU PERFORMED OTHER ANALYSES ON AMERENIP'S COSS?**

A Yes. Since the total company ROR of 2.7% is an average value, I performed an additional study to determine the NOI from each class as if its ROR was exactly the same as the company average. I then calculated the difference between this NOI value and the class's NOI under present rates as determined by the COSS.

Also, since the Company has proposed to raise the rates of every customer class by an equal percentage, I performed a similar analysis to show the subsidy given or received by each customer class were the Commission to grant Ameren's request.

**Q PLEASE DESCRIBE THE STEPS OF THIS ANALYSIS?**

A I began with the COSS filed by AmerenIP, which included a "claimed" or target return on rate base of 9.02%. Using the same process as I have already described, I found the total company revenue increase to be 41.1% above the total company sales revenue at present rates. I then calculated the class subsidies, again using the same procedures as described earlier.

**Q WHAT ARE THE RESULTS OF THESE ANALYSES?**

A The results are shown in Figure 5.

**Figure 5: AmerenIP's Class Subsidies at Present Rates and Proposed Revenue Allocation**

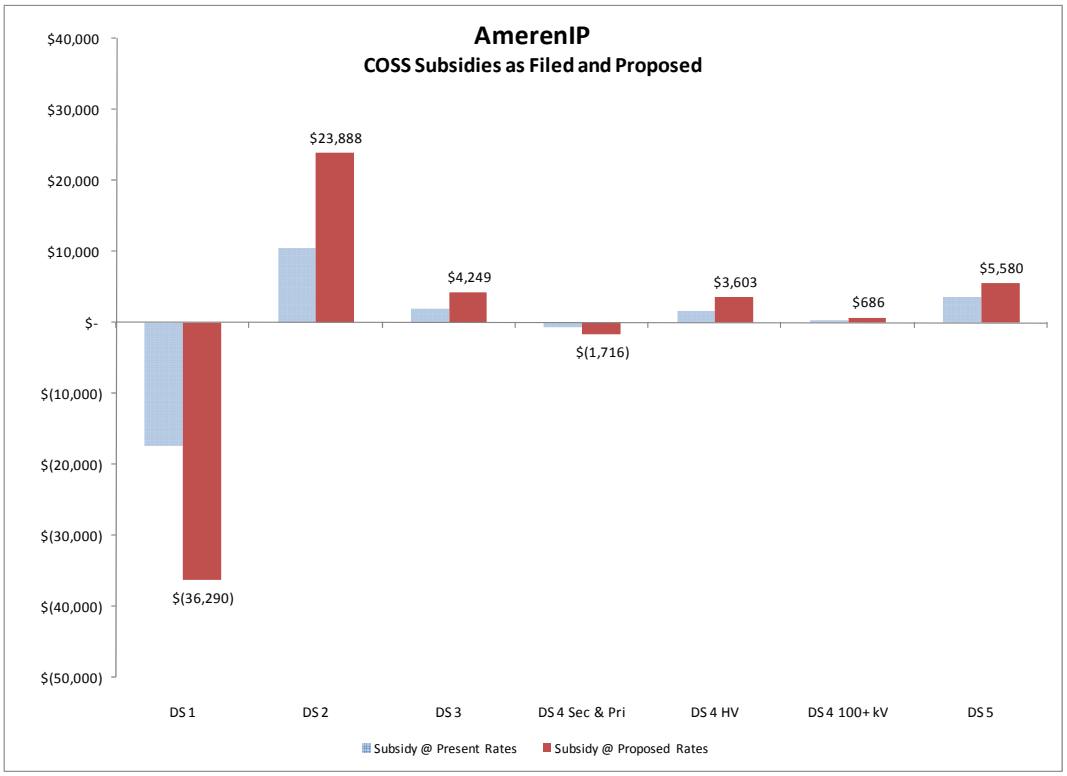



Figure 5 shows that, according to the AmerenIP COSS, two classes (DS-1 and DS-4 secondary and primary) receive a subsidy from the other classes. The figure also shows that increasing the rates of every class as Ameren has proposed will exacerbate the subsidies given or received.

I have argued that the AmerenIP COSS is deficient in that it does not recognize the cost impact of the minimum distribution system. I also argue that valid COSS results should never be applied in a way that worsens the inequities and subsidies given or received by customer classes.

**Q HAVE YOU MODIFIED THE COMPANY'S COSS TO ALLOCATE CUSTOMER- AND DEMAND-RELATED COSTS BY INCORPORATING MDS PRINCIPLES?**

A Yes. My changes to the AmerenIP COSS are the same as those described for all three studies in my testimony above.

**Q WHAT EFFECT DO YOUR MODIFICATIONS HAVE ON THE RESULTS OF THE COSS?**

A I've summarized the results from the modified COSS in Table 10.

**TABLE 10**

**AmerenIP Proposal vs. IIEC Proposal with Modified COSS**

| | | AmerenIP | | Modified COSS | |
|---|---|---|---|---|---|
| Line | Rate Class | Rate of Return | Proposed Increase | Rate of Return | Reqd Increase |
| 1 | DS 1 (Residential) | 0.7% | 41.1% | 0.3% | 63.8% |
| 2 | DS 2 | 8.0% | 41.1% | 8.5% | 2.5% |
| 3 | DS 3 | 4.6% | 41.1% | 6.9% | 11.2% |
| 4 | DS 4 - Sec & Pri | 1.2% | 41.1% | 3.1% | 41.6% |
| 5 | DS 4 - High Voltage | 7.1% | 41.1% | 7.1% | 10.6% |
| 6 | DS 4 - 100+ kV | NM | 41.1% | NM | -40.3% |
| 7 | Total DS 4 | 4.4% | 41.1% | 5.5% | 20.9% |
| 8 | DS 5 | 6.5% | 41.1% | 7.1% | 12.8% |
| 9 | AmerenIP Total | 2.7% | 41.1% | 2.7% | 41.1% |

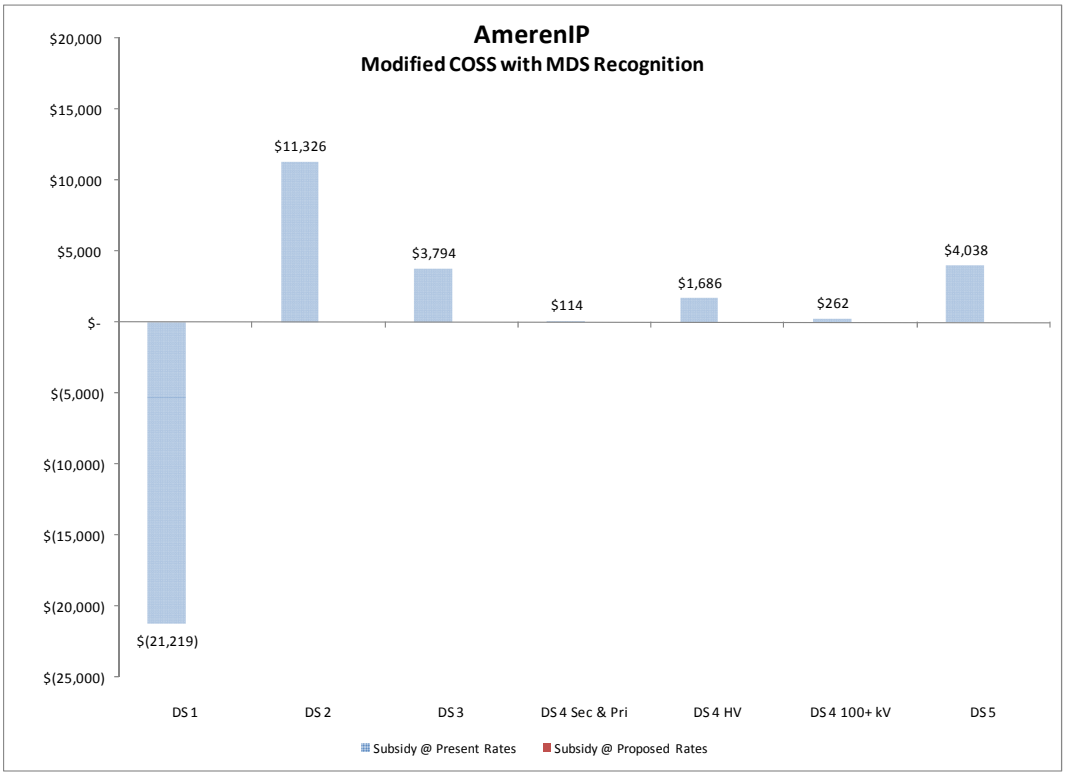
**Q PLEASE DESCRIBE WHAT TABLE 10 SHOWS.**

A Table 10 shows that the modifications to AmerenIP's COSS to recognize MDS had little impact on the overall company ROR at present rates, or the total increase in revenue needed to achieve the target ROR. However, the impact on the ROR and revenue allocation of individual rate classes is significant. In general, cost and rate

base responsibility was shifted from classes with relatively few numbers of customers to classes with relatively large numbers of customers.

This shift was expected because the Company's original COSS for AmerenIP allocated all of the costs from FERC Accounts 364 through 367 on the basis of demand, whereas recognizing the MDS allocated the costs incurred to conform to the NESC on the basis of customer numbers. MDS recognition within the COSS provides a clearer, more accurate picture of the subsidies to individual classes under present rates as shown in Figure 6.

**Figure 6: AmerenIP Class Subsidies:**
**Modified COSS and Revenue Allocation at Cost of Service**




**Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

## Qualifications of David L. Stowe

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A David L. Stowe. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

**Q PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

**Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I was graduated from the Kansas State University's College of Electrical and Computer Engineering in 1987, with a Bachelor of Science degree in Electrical Engineering. Following my graduation, I worked with the Kansas Corporation Commission ("KCC") as a Utilities Engineer. My responsibilities included the review and engineering analysis of utility filings, investigations of compliance with the Commission's Orders and State laws, and filing and defending testimony regarding those finds. In addition, I served as Geographic Information Systems Coordinator as the KCC digitized and automated its utility facilities and territory maps from the original velum sheets.

In April of 1993, I accepted a position with the Missouri Public Service Commission where, again in the capacity of a Utilities Engineer, focused primarily on depreciation, jurisdictional allocations, and production cost modeling. My employment with the Commission also allowed me to complete the requirements for

Professional Engineer registration. I acquired my certificate for Professional Engineering registration in 1996.

From October 1995 until January 2002, I developed my expertise in computer engineering and communications; first acting as a Unix System Administrator and Oracle DBA with Kansas City Power and Light, and later offering both hardware and software consulting services to corporations with enterprise-wide application requirements with Digital Equipment Corporation and Compaq. During this time, I was also the president and owner of a company that installed analog and digital communication systems in cellular phone towers.

In January of 2002, I joined the Analytic Services Department of Aquila, Inc. as a Senior Regulatory Analyst where I was primarily responsible for developing and maintaining cost of service models for each of Aquila's electrical territories. In addition, I was solely responsible for completing associated engineering studies to determine the primary and secondary portions of each subsidiaries' distribution systems, calculating the zero intercept values for the subsidiaries' poles, conductors, conduits, and transformers, performing customer impact analyses, and assisting in rate design.

In October of 2007, I joined Brubaker & Associates, Inc. as a consultant. Since that time, I have assisted on cost of service, revenue requirement, and tariff issues in Illinois, Montana, Wyoming, and New York.

I have testified before the State Commissions of Kansas, Missouri, and Colorado, and Illinois.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.