EXHIBIT

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Case No.: ER-2012-0166

DIRECT TESTIMONY

OF

BARBARA A. MEISENHEIMER

Submitted on Behalf of the Office of the Public Counsel

UNION ELECTRIC COMPANY D/B/A
AMEREN MISSOURI

CASE NO. ER-2012-0166

July 19, 2012

OPC Exhibit No 403
Date 9-27-12 Reporter KF
File No ER-2012-0166

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	File No. ER-2012-0166

AFFIDAVIT OF BARBARA A. MEISENHEIMER

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Barbara A. Meisenheimer, of lawful age and being first duly sworn, deposes and states:

1. My name is Barbara A. Meisenheimer. I am a Chief Utility Economist for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony.

3. I hereby swear and affirm that my statements contained in the attached affidavit are true and correct to the best of my knowledge and belief.

Barbara A. Meisenheimer

Subscribed and sworn to me this 19th day of July 2012.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

JERENE A. BUCKMAN
My Commission Expires
August 23, 2013
Cole County
Commission #09754037

Jerene A. Buckman
Notary Public

My commission expires August 23, 2013.

Ameren Missouri
Class Cost of Service and Rate Design

ER-2012-0166

Direct Testimony
of
Barbara Meisenheimer

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. Barbara A. Meisenheimer, Chief Utility Economist, Office of the Public Counsel, P. O. Box 2230, Jefferson City, Missouri 65102. I am also an adjunct instructor for William Woods University.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN THIS CASE?

A. Yes, I submitted direct testimony related to the determination of revenue requirement on July 6, 2012.

Q. WHAT IS YOUR PREVIOUS EXPERIENCE IN THE PREPARATION OF CLASS COST OF SERVICE STUDIES?

A. Over the past 15 years I have prepared and supervised the preparation of cost of service studies on behalf of Public Counsel. These studies have included class cost of service studies related to natural gas, water and electric utilities, and telecommunications service cost studies.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to present Public Counsel's Class Cost of Service (CCOS) study results and preliminary inter-class rate design recommendations.

Q. WHAT IS THE MAIN PURPOSE OF PERFORMING A CCOS STUDY?

A. The primary purpose of a CCOS study is to determine the relative class cost responsibility for each customer class by allocating costs among the classes based on principles of cost causation. CCOS study results also provide guidance for determining how rates (e.g., customer charges) should be designed to collect revenues from customers within a class, depending on customer usage levels and patterns of use.

Q. WHAT IS THE RELATIVE IMPORTANCE OF CCOS STUDY RESULTS IN DEVELOPING RATE DESIGN?

A. CCOS study results provide the Commission with a general guide in setting the just and reasonable rate for the provision of service based on costs. In addition, other factors are also relevant considerations when setting rates including the value of a service, affordability, rate impact, rate continuity, etc. A determination as to the particular manner in which the results of a cost of service study and all the other factors are balanced in setting rates can only be determined on a case-by-case basis.

Q. HOW DO YOU RECOMMEND THAT THE COMMISSION ACCOMMODATE FACTORS SUCH AS AFFORDABILITY, RATE IMPACT, AND RATE CONTINUITY IN DETERMINING RATE DESIGN?

A. Generally, I recommend that the Commission adopt a rate design that balances movement toward cost of service with rate impact and affordability considerations. To reach this balance, I believe that in cases where the existing revenue structure departs greatly from the class cost of service, the Commission should impose, at a maximum, class revenue shifts equal to one half of the "revenue neutral shifts" indicated by Public Counsel's CCOS studies. Revenue neutral shifts are shifts that hold overall company revenue at the existing level but allow for the share attributed to each class to be adjusted to reflect the cost responsibility of the class. In addition to moving half way to the revenue neutral shifts, I recommend that if the Commission determines that an overall increase in revenue requirement is necessary in this case, then no customer class should receive a net decrease as the combined result of: (1) the revenue neutral shift that is applied to that class, and (2) the share of the total revenue increase that is applied to that class. Likewise, if the Commission determines that an overall decrease in revenue requirement is necessary, then no customer class should receive a net increase as the combined result of: (1) the revenue neutral shift that is applied to that class, and (2) the share of the total revenue decrease that is applied to that class.

Q. HOW DO YOUR STUDIES DIFFER FROM THOSE YOU PRESENTED IN PAST ELECTRIC SERVICE RATE CASES?

A. The primary difference relates to the method used to apportion the cost of production facilities to customer classes. In past electric cases I have recommended the use of a "time of use" (TOU) production allocator which assigned production facilities costs to customer classes on an hour by hour basis in proportion to each class's demand during the hours that particular production facilities were generating power. The development of the TOU allocator required specialized output from an engineering model designed to simulate a least cost dispatch of generation facilities during each of 8760 hour in a year. Public Counsel did not have access to the required model outputs necessary to prepare a TOU study for this case.

Q. WHAT METHOD OF ALLOCATING PRODUCTION COSTS ARE YOU RECOMMENDING IN THIS CASE?

A. My primary recommendation is to apportion production costs to classes using a weighted average of the annual energy use and share of system peak (coincident peak) demand for each class. I will refer to this allocator as Avg & 4CP where Avg represents average annual energy usage and 4CP represents coincident peak demand based on class demands during the 4 highest monthly system peak hours. The significance of such an allocator is that it recognizes that production costs are influenced by load characteristics throughout the year as well as by peaking requirements.

As an alternative, I have also prepared a study which allocates production and production-related costs using a weighted average of annual usage and excess demand. Excess demand is measured as the difference between the sum of all classes' maximum demand (whether or not the maximum demands occur at the coincident peak) and average annual demand. I will refer to this allocator as Avg & Excess 4NCP. Conceptually, this allocator is similar to the production cost allocator used by the Company. If the Commission decides to adopt an Average and Excess method for assigning production and production-related costs to consumers then I recommend the alternative CCOS study presented in my testimony.

Q. HAVE YOU PROVIDED SCHEDULES ILLUSTRATING YOUR CCOS STUDY RESULTS?

A. Yes. The class cost of service study results associated with use of the Avg & 4CP are provided in Schedule BAM DIR-1. The class cost of service study results associated with use of the Avg & Excess 4NCP are provided in Schedule BAM DIR-2.

CLASS COST OF SERVICE STUDY METHODS

Q. PLEASE OUTLINE THE BASIC ELEMENTS OF PREPARING A CCOS STUDY.

A. A CCOS Study is designed to functionalize, classify, and allocate costs.

Functionalizing costs involves categorizing accounts by the type of electric utility function(s) with which each account is associated. The categories of accounts include Production, Transmission, Distribution, Customer Accounts, Administrative and General, etc.

The next step is to classify costs as customer-related, demand-related, commodity-related, or "other" costs. Customer-related costs vary in relation to the number of customers. Demand-related costs vary with usage during different periods such as peak and average load periods. Commodity-related costs vary with annual energy consumption. For example, the cost associated with meter plant, and meter reading expense are considered to be customer-related because they vary primarily based on the number of customers served and might occur whether or not the customer uses any electricity.

The final step in the CCOS is to develop and apply allocation factors that apportion a reasonable share of jurisdictional costs to each customer class. Allocation factors should be developed in a manner that is consistent with the functionalization and classification of costs described above. For example, unweighted customer-related cost allocation factors are expressed as ratios that reflect the proportion of customers in a particular class to the total number of customers that contribute to the causation of the relevant cost. Likewise, demand-related allocators should reflect each class's use during specific time periods and commodity-related allocators should reflect each class's annual consumption. In simpler terms, if the cost for a particular activity were thought of as a pie, then allocators would represent the size of the slices of the "cost" pie that each class would be assigned.

Q. WHICH CUSTOMER CLASSES ARE USED IN YOUR CCOS STUDIES?

A. For both studies of the Ameren system, I used a Residential Class (Residential), a Small General Service Class (SGS), a Large General Service/Small Primary

Service Class (LGS/SPS), a Large Power Service Class (LPS), a Large Transmission Class (LTS) and a Lighting Class (Lighting).

Q. ON WHAT DATA ARE YOUR CCOS STUDIES BASED?

A. My CCOS studies are based primarily on data provided by the Company and Staff. I obtained data related to investments, expenses and revenues from the Staff Accounting Schedules filed on July 6, 2012. The Company's workpapers were the primary source of the information I used to develop allocations related to annual energy usage, peak demands, investment weightings and customer counts.

Q. HOW IS INTANGIBLE PLANT ALLOCATED IN YOUR CCOS STUDIES?

A. Intangible Plant (FERC Account No. 301) pertains to organization cost. It includes all fees paid to federal or state governments for the privilege of incorporation along with related expenditures. Generally, it should be allocated to each customer class according to the benefits each receives from the existence of this business, or according to the extent to which each class contributes to the overall cost of conducting the business. In this case, I have applied a Gross Plant Allocator to Intangible Plant.

Q. HOW IS PRODUCTION PLANT ALLOCATED IN YOUR CCOS STUDIES?

A. Production Plant includes the cost of land, structures and equipment used in connection with power generation. Both demand and energy characteristics of a system's loads are important determinants of production plant costs. In my first CCOS the Average portion of the Avg & 4CP is estimated as average annual energy usage and the 4CP represents coincident peak demand based on class demands during the 4 highest monthly system peak hours.

Q. IS A WEIGHTED AVERAGE AND COINCIDENT PEAK (AVG & CP) METHOD THAT ALLOWS DISCRETION IN SELECTION OF THE NUMBER OF COINCIDENT PEAKS AMONG THE NARUC-RECOGNIZED PRODUCTION CAPACITY COST ALLOCATION METHODS?

A. Yes.

Q. PLEASE EXPLAIN.

A. Part IV B. of the NARUC Electric Utility Cost Allocation Manual describes methods for developing energy-weighted production plant cost allocations. Section 4 of Part IV discusses production cost allocations based on judgmental energy weightings. Page 57-59 of the NARUC Manual specifically recognizes weighted average and coincident peak methods where the coincident peak (CP) may be estimated based on more than one period of peak use. The Manual describes the method as follows:

> Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weightings into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specific group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

The Manual goes on to provide two examples of weighted methods, one based on average demand and a single period of coincident peak use (A&1CP) and another that incorporates average demand and 12 periods of peak use (A&12CP) in developing an allocator. I have included a copy of the relevant pages in Schedule

BAM DIR-3 to this testimony. The 4CP I used to represent the peak portion of the allocator fall well within the number of peak periods recognized in the NARUC Manual.

I used a measure of load factor (LF) as the weight assigned to the average portion of the allocator and used 1- LF as the weight assigned to the peak portion of the allocator. As described in the NARUC Manual, I calculated the load factor as the average demand divided by the system coincident peak demand.

Q. IS THE 4CP REPRESENTATIVE OF THE PEAK DEMAND ON AMEREN'S SYSTEM?

A. Yes. The 4CP is reasonably representative of the peak demand on Ameren's system. As illustrated in Table 1, the 4CP I used reflects periods when demand was in excess of 85% of the system's maximum peak.

Table 1. Class CP Hour Demands @ Generation kW

	Residential	SGS	LGS/SPS	LPS	LTS	Lighting	Totals	% of System Peak
Oct-10	1,501,768	582,810	1,883,184	520,621	471,052	-	4,959,435	61%
Nov-10	2,703,118	579,884	1,707,358	431,007	486,047	55,358	5,962,773	73%
Dec-10	3,491,745	572,931	1,500,883	394,416	487,367	55,160	6,502,502	80%
Jan-11	**3,356,690**	**655,411**	**1,986,475**	**442,516**	**486,227**	**16,196**	**6,943,515**	**85%**
Feb-11	3,013,151	583,600	1,953,016	407,839	487,790	4,861	6,450,257	79%
Mar-11	2,084,712	636,026	1,762,032	489,995	486,711	-	5,459,477	67%
Apr-11	1,952,900	469,231	1,703,892	466,183	485,297	-	5,077,502	62%
May-11	2,055,215	628,716	1,780,212	503,845	487,138	-	5,455,126	67%
Jun-11	**3,185,310**	**752,803**	**2,040,057**	**554,793**	**487,041**	-	**7,020,005**	**86%**
Jul-11	**3,657,177**	**851,404**	**2,217,671**	**565,685**	**486,157**	-	**7,778,095**	**95%**
Aug-11	**3,892,661**	**869,772**	**2,310,249**	**585,892**	**487,450**	-	**8,146,023**	**100%**
Sep-11	3,030,705	739,069	1,978,304	555,694	486,500	-	6,790,272	83%

Q. WHY IS IT REASONABLE TO USE MULTIPLE PEAKS IN DEVELOPING THE MEASURE OF COINCIDENT PEAK USED IN THE PRODUCTION ALLOCATOR?

A. As illustrated in Table 2, a class's relative share of system demand may vary significantly. Using multiple measures of coincident peak reduces the likelihood of relying on an anomalous single peak as the basis of the allocator. In addition, the system is designed to meet a range of system demands and a class's relative share may vary in that range. I believe it is reasonable to include more than simply the highest single peak to reflect the class's relative share of system demand. Allowing for peaks in excess of 85% retains the conceptual focus on determining peak demand while also reflecting each class's relative share of variation in system peak demands.

Table 2. Class Share of Coincident Peak

	Residential	SGS	LGS/SPS	LPS	LTS	Lighting
Jan-11	**48.34%**	**9.44%**	**28.61%**	**6.37%**	**7.00%**	**0.23%**
Jun-11	**45.37%**	**10.72%**	**29.06%**	**7.90%**	**6.94%**	**0.00%**
Jul-11	**47.02%**	**10.95%**	**28.51%**	**7.27%**	**6.25%**	**0.00%**
Aug-11	**47.79%**	**10.68%**	**28.36%**	**7.19%**	**5.98%**	**0.00%**

Q. PLEASE DESCRIBE THE ALTERNATIVE AVERAGE AND EXCESS 4NCP PRODUCTION ALLOCATOR?

A. The alternative Avg & Excess 4NCP production allocator is a weighted average of annual usage and excess demand. Excess demand is measured as the difference between the sum of all classes' maximum demand (whether not the maximum demands occur at the coincident peak) and average annual energy usage. I have prepared the Avg & Excess 4NCP consistent with the derivation

discussed in the NARUC Electric Cost Allocation Manual. As described in the NARUC Manual, I calculated the load factor as the average demand divided by the system peak demand.

Please note that an Average & Excess allocator is not Public Counsel's preferred method of allocating production costs. I have developed this allocator and prepared a CCOS using the allocator for Commission consideration if the Commission rejects use of the Avg and 4CP presented in this testimony. In my opinion Ave & Excess allocation methods disproportionately assign costs to the Residential and SCS classes. As illustrated in Table 3, Average and Excess allocators approximate pure peak allocations, focusing too heavily on a few peak hours and a giving little weight to annual energy usage.

Table 3. Comparison of Class Production Allocations

Allocation Method	Residential	SGS	LGS/SPS	LPS	LTS	Lighting
Pure Energy Allocation	37.18%	9.61%	32.00%	10.02%	10.70%	0.49%
OPC Average & 4 Coincident Peak	41.65%	10.00%	30.49%	8.75%	8.83%	0.30%
OPC Average & Excess 4 Non-Coincident Peak	46.88%	10.65%	28.47%	7.23%	6.05%	0.73%
Company Allocator	46.89%	10.65%	28.47%	7.23%	6.04%	0.72%
Pure Coincident Peak Allocation	47.15%	10.47%	28.62%	7.19%	6.51%	0.05%
Equal Weighting of Energy and Coincident Peak	42.16%	10.04%	30.31%	8.60%	8.61%	0.27%

Q. HOW DID YOU ALLOCATE TRANSMISSION PLANT?

A. Transmission Plant includes the cost of land, structures and equipment used in connection with transmission operations. Transmission facilities are installed to provide reliable service throughout the year including periods of scheduled maintenance. It can also, at times, substitute for generation and can minimize the cost of generation facilities through the sales or purchases of power. Therefore,

Transmission Plant costs can be equitably allocated on the same basis as the Production Plant. Accordingly, I chose to use the same allocator that I used for Production Plant to allocate Transmission Plant.

Q. HOW DID YOU ALLOCATE DISTRIBUTION PLANT?

A. Distribution Plant includes the cost of land, structures and equipment used in connection with distribution operations. 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.

In the functionalization and allocation of Distribution Plant, my studies reflect that distribution facilities provide service at two voltage levels: primary and secondary, and that some large industrial customers may choose to take service at primary voltages because of their large electrical requirements. Different allocation factors were used for allocating costs at different levels of the distribution system. Company witness Warwick relied on a Company study which stratified portions of the costs reflected in the Distribution Accounts as demand-related at various voltages and a portion of the costs as customer-related. I used the Company's study results, however, I disagree that it is appropriate to identify a portion of the costs in Distribution Accounts 364-368 as being directly related to the number of customers. While I believe it would be appropriate to allocate costs classified as "other" based on demand at secondary or at primary voltage, I did not have information in sufficient detail to do so. Instead of allocating these costs directly on the number of customers, as the Company did, I classified these costs as "other" and allocated the costs to classes on the basis of weighted meter investment. While this effectively does allocate the costs in

relation to the number of customers, the primary impact is in determining a reasonable level of customer charge which I address later in this testimony.

Q. HOW DID YOU ALLOCATE METER-RELATED FACILITIES?

A. Meter facilities costs are generally related to each individual customer. New investment occurs when a new customer is added to the system. Therefore, meter costs are usually classified as customer-related. I allocated meter costs based on a weighted meter investment.

Q. HOW DID YOU ALLOCATE SERVICE RELATED FACILITIES?

Service facilities are classified as customer-related. I allocated services costs based on weighted meter investment.

Q. PLEASE SUMMARIZE THE ALLOCATION OF DISTRIBUTION COSTS?

Service facilities are classified as customer-related. I allocated services costs based on weighted meter investment.

The functional categories and classifications for Distribution Plant are as follows:

360-362	Distribution Substations	Demand at Primary Station
364	Poles Towers and Fixtures	Demand at Primary, Weighted Meter Investment, Demand at Secondary
365	Overhead Conductors & Devices	Demand at Primary, Weighted Meter Investment, Demand at Secondary
366	Underground Conduit	Demand at Primary, Weighted Meter Investment, Demand at Secondary
367	Underground Conductors & Devices	Demand at Primary, Weighted Meter Investment, Demand at Secondary

368	Line Transformers	Transformer Demand, Weighted Meter Investment
369	Services	Weighted Meter Investment
370	Meters	Weighted Meter Investment

Q. HOW DID YOU ALLOCATE GENERAL PLANT?

A. General Plant includes land, structures and equipment used in support of Production, Transmission and Distribution Plant. Therefore, it was allocated using a composite allocator based net non-general plant.

Q. PLEASE DISCUSS THE METHODS THAT YOU USED TO ALLOCATE EXPENSES.

A. For the expenses that could not be directly assigned, consistent with the principle that "expenses follow plant", the allocators that I applied to the expenses accounts were the same as those applied to the Production, Transmission, and Distribution Plant accounts to which the expenses are related.

Q. HOW DID YOU ALLOCATE POWER PRODUCTION EXPENSES?

A. Power Production Expenses were broken down into demand-related and energy-related production and purchased power costs. The demand-related expenses were allocated based on the demand-related allocators in my studies. The energy-related expenses were allocated based on class kWhs at generation.

Q. HOW WERE TRANSMISSION EXPENSES ALLOCATED?

A. Transmission Expenses were allocated according to the "expenses follow plant" principle. The allocators applied to transmission expenses were the same as those I applied to transmission plant.

Q. HOW WERE DISTRIBUTION EXPENSES ALLOCATED?

A. Distribution Expenses were allocated according to the "expenses follow plant" principle. The allocators applied to distribution expenses were the same as those I applied to the plant associated with those expenses. For expenses that are not associated with any particular category of distribution plant, such as supervision and engineering, I used an aggregate distribution expense allocator based on the sum of the primary portion of Accounts 364-367.

Q. HOW DID YOU ALLOCATE CUSTOMER ACCOUNTS EXPENSES?

A. I allocated some account expenses to all customer classes based on unweighted customer numbers. I used a weighted meter reading allocator for Meter Reading (Account 902). I used the Company's allocator to allocate Uncollectible Accounts (Account 904). The rest I allocated based on a composite customer account allocator.

Q. HOW DID YOU ALLOCATE CUSTOMER SERVICE EXPENSES AND SALES EXPENSES?

A. Customer Service and Sales Expenses including Accounts 907, 908, 909, 910, 911, 912, 913 and 916 were allocated based on customers, weighted customers or a composite allocator.

Q. HOW ARE ADMINISTRATIVE AND GENERAL (A&G) EXPENSES ALLOCATED?

A. Property Insurance expense (Account 924) was allocated on the basis of non general gross plant or cost of services. Rents (Account 924) and Maintenance of General Plant (Account 931) were allocated based on gross plant expense. Maintenance of General Plant (Account 935) was allocated on the basis of general plant. The A&G accounts related to Regulatory (Account 928), Franchise

Expense (Account 927) and Miscellaneous Expense (Account 930) were allocated based on overall cost of service. The remaining A&G accounts were allocated based on payroll.

Q. HOW DID YOU ALLOCATE PROPERTY TAXES?

A. I allocated property taxes on the basis of allocated total gross plant.

Q. HOW DID YOU ALLOCATE STATE AND FEDERAL INCOME TAXES?

A. These taxes were allocated on the basis of rate base since a utility company's income taxes will be a function of the size of its rate base, and thus each class should contribute revenues for income taxes in proportion with the amount of rate base that is necessary to serve it.

Q. PLEASE DESCRIBE THE RESULTS OF PUBLIC COUNSEL'S CLASS COST OF SERVICE STUDY.

A. Schedule BAM DIR-1 and Schedule BAM DIR-2 show the results of Public Counsel's Class COS studies. Since a CCOS study is designed to determine the relative cost responsibility of customer classes, the results are based on the assumption that total company revenues remain constant. Line 11 of each schedule shows the current revenue percentage by class. Line 32 of each schedule shows the change in class revenue percentage to achieve equalized rates of return. The study results show that to equalize class rates of return the Residential class would require a 1.58% revenue neutral reduction under the Avg & 4CP CCOS or a 2.51% revenue neutral increase under the Avg & Excess 4NCP CCOS. To equalize class rates of return the SGS class would require a -1.48% revenue neutral reduction under the Avg & 4CP CCOS or a .61% revenue neutral increase

under the Avg & Excess 4NCP CCOS. According to both CCOS studies, to equalize returns, both the LGS/SPS and Lighting class would need to be reduced and both LPS and LTS would need to increase.

Q. BASE ON YOUR CCOS STUDY RESULTS WHAT IS YOUR RECOMMENDATION REGARDING REVENUE NEUTRAL SHIFTS?

A. My CCOS studies suggest that the Residential Class and Small General Service Class are near system average and should not be subject to a revenue neutral increase.

Q. BASED ON YOUR CCOS RESULTS WHAT CUSTOMER CHARGES DO YOU RECOMMEND?

A. My CCOS studies suggest the average customer cost recoverable in a customer charge is a little under $6 for the Residential class and about $10.65 for the Small General Service Class. I do not anticipate significant changes in these calculations in future study updates. The current customer charges exceed these costs so I recommend that there be no increase in the Residential or SGS customer charges in this proceeding.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

OPC CCOS Study Summary - A&4CP Production Demand Allocator

		TOTAL	RES	SGS	LGS/SPS	LPS	LTS	Lighting
1	O & M EXPENSES	1,969,287,865	848,974,692	206,328,996	575,989,360	167,809,758	161,143,534	9,041,524
2	DEPREC. & AMORT. EXPENSE	419,139,538	201,823,450	50,644,211	114,637,366	28,751,435	22,375,549	907,527
3	TAXES	230,415,300	107,822,877	26,581,263	64,541,490	16,921,384	13,950,811	597,474
4								
5	TOTAL EXPENSES AND TAXES	2,618,842,703	1,158,621,020	283,554,470	755,168,216	213,482,577	197,469,894	10,546,525
6		0	0	0	0	0	0	0
7	CURRENT RATE REVENUE	2,585,401,417	1,177,189,202	288,636,756	747,206,548	189,217,082	148,358,398	34,793,431
8	OFFSETTING REVENUES:							
9	Reveue Credits	364,008,037	152,970,173	36,807,686	110,335,721	31,468,057	31,362,540	1,063,859
10								
11	Total Offsetting Revenues	364,008,037	152,970,173	36,807,686	110,335,721	31,468,057	31,362,540	1,063,859
12								
11	TOTAL CURRENT REVENUE	2,949,409,454	1,330,159,375	325,444,442	857,542,269	220,685,139	179,720,938	35,857,290
12	CLASS % OF CURRENT REVENUE	100.00%	45.10%	11.03%	29.08%	7.48%	6.09%	1.22%
13								
14	OPERATING INCOME	305,255,987	171,538,356	41,889,972	102,374,053	7,202,562	(17,748,950)	25,310,764
15								
16	TOTAL RATE BASE	6,702,797,478	3,110,459,391	765,792,107	1,894,321,102	500,124,932	415,914,451	16,185,495
17								
18	IMPLICIT RATE OF RETURN	4.55%	5.51%	5.47%	5.40%	1.44%	-4.27%	156.38%
19								
20	EQUAL RATE OF RETURN	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%	4.55%
21								
22	REQUIRED OPERATING INCOME							
23	Equalized (OPC) Rates of Return	305,255,987	141,655,235	34,875,382	86,270,376	22,776,480	18,941,401	737,113
24								
25	TOTAL COST OF SERVICE	2,924,098,690	1,300,276,254	318,429,853	841,438,592	236,259,057	216,411,295	11,283,638
26	CLASS % of COS	100.00%	44.47%	10.89%	28.78%	8.08%	7.40%	0.39%
27								
28	MARGIN REVENUE REQUIRED							
29	to Equalize Class ROR - Revenue Neutral	2,949,409,454	1,311,531,342	321,186,156	848,722,017	238,304,096	218,284,534	11,381,309
30								
31	COS INDICATED REVENUE NEUTRAL SHIFT	0	(18,628,034)	(4,258,286)	(5,820,252)	17,618,957	38,563,596	(24,475,981)
32	% REVENUE NEUTRAL RATE INCREASE	0.00%	-1.58%	-1.48%	-1.18%	9.31%	25.99%	-70.35%
33	CLASS % OF REVENUE AFTER REVENUE SHIFT	100.00%	44.81%	11.00%	28.56%	8.00%	7.23%	0.40%

OPC CCOS Study Summary - A&E 4NCP Production Demand Allocator

		TOTAL	RES	SGS	LGS/SPS	LPS	LTS	Lighting
1	O & M EXPENSES	1,969,287,865	883,520,931	210,644,638	562,646,915	157,757,984	142,820,391	11,897,006
2	DEPREC. & AMORT. EXPENSE	419,139,538	214,944,486	52,281,192	109,562,780	24,930,088	15,427,948	1,993,043
3	TAXES	230,415,300	115,737,469	27,569,214	61,482,242	14,617,247	9,757,104	1,252,024
4								
5	TOTAL EXPENSES AND TAXES	2,618,842,703	1,214,202,886	290,495,044	733,691,938	197,305,319	168,005,443	15,142,073
6		0	0	0	0	0	0	0
7	CURRENT RATE REVENUE	2,585,401,417	1,177,189,202	288,636,756	747,206,548	189,217,082	148,358,398	34,793,431
8	OFFSETTING REVENUES:							
9	Reveue Credits	364,008,037	171,544,061	39,130,970	103,171,998	26,068,799	21,494,376	2,597,833
10								
11	Total Offsetting Revenues	364,008,037	171,544,061	39,130,970	103,171,998	26,068,799	21,494,376	2,597,833
12								
11	TOTAL CURRENT REVENUE	2,949,409,454	1,348,733,263	327,767,726	850,378,546	215,285,881	169,852,774	37,391,264
12	CLASS % OF CURRENT REVENUE	100.00%	45.73%	11.11%	28.83%	7.30%	5.76%	1.27%
13								
14	OPERATING INCOME	308,317,560	134,530,377	37,272,681	116,686,608	17,980,562	1,847,331	22,249,191
15								
16	TOTAL RATE BASE	6,702,797,478	3,339,854,059	794,421,286	1,805,635,101	433,333,391	294,394,420	35,159,220
17								
18	IMPLICIT RATE OF RETURN	4.60%	4.03%	4.69%	6.46%	4.15%	0.63%	63.28%
19								
20	EQUAL RATE OF RETURN	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%	4.60%
21								
22	REQUIRED OPERATING INCOME							
23	Equalized (OPC) Rates of Return	308,317,560	153,627,744	36,542,061	83,056,218	19,932,617	13,541,655	1,617,266
24								
25	TOTAL COST OF SERVICE	2,927,160,263	1,367,830,630	327,037,105	816,748,156	217,237,936	181,547,098	16,759,339
26	CLASS % of COS	100.00%	46.73%	11.17%	27.90%	7.42%	6.20%	0.57%
27								
28	MARGIN REVENUE REQUIRED							
29	to Equalize Class ROR - Revenue Neutral	2,949,409,454	1,378,227,439	329,522,897	822,956,216	218,889,150	182,927,028	16,886,726
30								
31	COS INDICATED REVENUE NEUTRAL SHIFT	(0)	29,494,175	1,755,171	(27,422,331)	3,603,269	13,074,254	(20,504,538)
32	% REVENUE NEUTRAL RATE INCREASE	0.00%	2.51%	0.61%	-3.67%	1.90%	8.81%	-58.93%
33	CLASS % OF REVENUE AFTER REVENUE SHIFT	100.00%	46.67%	11.23%	27.84%	7.46%	6.24%	0.55%

4. Judgmental Energy Weightings

Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weighting into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specified group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

TABLE 4-14

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 1 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 1 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Avg. Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	34.84	233,869,251	30.96	120,512,062	354,381,313
LSMP	37.25	250,020,306	33.87	131,822,415	381,842,722
LP	24.63	165,313,703	31.21	121,450,476	286,764,179
AG&P	3.29	22,078,048	3.22	12,545,108	34,623,156
SL	0.00	0	0.74	2,864,631	2,864,631
TOTAL	100.00	671,281,308	100.00	389,194,692	$1,060,476,000

Notes: The portion of the production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of (a) the annual system peak demand, Table 4-3, column 2, plus (b) the average system demand for the test year, Table 4-10A, column 3. Thus, the percentage classified as demand-related is equal to 13591/(13591+7880), or 63.30 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the system peak demand and the average system demand. For the example, this percentage is 36.70 percent.

Some columns may not add to indicated totals due to rounding.

TABLE 4-15

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	198,081,400	30.96	137,226,133	335,307,533
LSMP	38.43	237,225,254	33.87	150,105,143	387,330,397
LP	26.71	164,899,110	31.21	138,294,697	303,193,807
AG&P	2.42	14,960,151	3.22	14,285,015	29,245,167
SL	0.35	2,137,164	0.74	3,261,933	5,399,097
TOTAL	100.00	617,303,080	100.00	443,172,920	$1,060,476,000

Notes: The portion of production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of the 12 monthly system coincident peaks (Table 4-3, column 4) by the sum of that value plus the system average demand (Table 4-10A, column 3). Thus, for example, the percentage classified as demand-related is equal to 10976/(10976+7880), or 58.21 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the average demand and the average of the twelve monthly peak demands. For the example, 41.79 percent of production plant revenue requirements are classified as energy-related.

Another variant of the peak and average demand method bases the production plant cost allocators on the 12 monthly CPs and average demand, with 1/13th of production plant classified as energy-related and allocated on the basis of the classes' KWH use or average demand, and the remaining 12/13ths classified as demand-related. The resulting allocation factors and allocations of revenue responsibility are shown in Table 4-16 for the example data.

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

Rate	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	314,111,612	30.96	25,259,288	339,370,900
LSMP	38.43	376,184,775	33.87	27,629,934	403,814,709
LP	26.71	261,492,120	31.21	25,455,979	286,948,099
AG&P	2.42	23,723,364	3.22	2,629,450	26,352,815
SL	0.35	3,389,052	0.74	600,426	3,989,478
TOTAL	100.00	978,900,923	100.00	81,575,077	$1,060,476,000

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

Some columns may not add to indicated totals due to rounding.

C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

1. Production Stacking Methods

Objective: The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic