Exhibit No:
Issue(s): Class Cost of Service / Revenue Allocation / Rate Design
Witness: Steve W. Chriss
Sponsoring Party: Midwest Energy Consumers Group
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2021-0240

DIRECT TESTIMONY AND EXHIBITS OF

STEVE W. CHRISS

ON BEHALF OF

MIDWEST ENERGY CONSUMERS GROUP

SEPTEMBER 17, 2021

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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 Decrease Its	)	File No. ER-2021-0240
Revenues for Electric Service.	)	

AFFIDAVIT OF STEVE W. CHRISS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW STEVE W. CHRISS and on his oath declares that he is of sound mind and lawful age; that he prepared the attached Direct Testimony; and that the same is true and correct according to his best knowledge and belief, under penalty of perjury.

Further the Affiant sayeth not.

/s/ *Steve W. Chriss*____
Steve W. Chriss

Introduction

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

A. My name is Steve W. Chriss. My business address is 2608 SE J St., Bentonville, AR 72716-0550. I am employed by Walmart Inc. ("Walmart") as Director, Energy Services.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS DOCKET?

A. I am testifying on behalf of Midwest Energy Consumers Group ("MECG"), which is an incorporated association representing the interests of large commercial and industrial users of electricity. MECG members take electric service from Union Electric Company d/b/a Ameren Missouri ("Ameren" or "the Company") primarily on Service Classification No. 3(M) Large General Service Rate ("LGS"), Service Classification No. 4(M) Small Primary Service Rate ("SP"), and Service Classification No. 11(M) Large Primary Service Rate ("LP").

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. In 2001, I completed a Master of Science in Agricultural Economics at Louisiana State University. From 2001 to 2003, I was an Analyst and later a Senior Analyst at the Houston office of Econ One Research, Inc., a Los Angeles-based consulting firm. My duties included research and analysis on domestic and international energy and regulatory issues. From 2003 to 2007, I was an Economist and later a Senior Utility Analyst at the Public Utility Commission of Oregon in Salem, Oregon. My duties included appearing as a witness for PUC Staff in electric, natural gas, and telecommunications dockets. I joined the energy department at Walmart in July 2007 as Manager, State Rate Proceedings. I was promoted to Senior Manager, Energy Regulatory Analysis, in June 2011. I was promoted to my current position in October, 2016 and the position was re-titled in October, 2018. My Witness Qualifications Statement is attached as Exhibit SWC-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. Yes. I submitted testimony in Docket Nos. ER-2010-0036, EO-2012-0009, EC-2014-0224, ER-2014-0258, ER-2016-0023, EA-2016-0208, ER-2016-0179, ER-2016-0358, ET-2018-0063, ER-2018-0146, EM-2018-0012, ER-2018-0145, ER-2019-0335, and ER-2019-0374.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE OTHER STATE REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony in over 240 proceedings before 40 other utility regulatory commissions. I have also submitted testimony before legislative committees in Kansas, Missouri, North Carolina, and South Carolina. My testimony has addressed topics including, but not limited to, cost of service and rate design, return on equity, revenue requirements, ratemaking policy, large customer renewable programs, qualifying facility rates, telecommunications deregulation, resource certification, energy efficiency/demand side management, fuel cost adjustment mechanisms, decoupling, and the collection of cash earnings on construction work in progress.

Q. ARE YOU SPONSORING EXHIBITS IN YOUR TESTIMONY?

A. Yes. I am sponsoring the exhibits listed in the Table of Contents.

Q. DO MECG'S MEMBERS HAVE A SIGNIFICANT IMPACT ON MISSOURI'S ECONOMY?

A. Yes. For example, as shown on Walmart's website, Walmart operates 156 retail units and four distribution centers and employs over 43,000 associates in Missouri. In fiscal year ending 2021, Walmart purchased $6.9 billion worth of goods and services from Missouri-based suppliers, supporting over 68,000 supplier jobs.[1]

Purpose of Testimony and Summary of Recommendations

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide MECG's response to class cost of service and rate design issues in Ameren's rate case filing and to provide recommendations to assist the Commission in its thorough and careful consideration of the customer impact of the Company's proposed rate increase.

Q. PLEASE SUMMARIZE MECG'S RECOMMENDATIONS TO THE COMMISSION.

A. MECG's recommendations to the Commission are as follows:

1) MECG supports the allocation of production plant fixed costs using the Company's proposed Average & Excess ("A&E") allocator based on the four non-coincident

[1] http://corporate.walmart.com/our-story/locations/united-states#/united-states/missouri

peaks ("NCP") for each customer class (together, "A&E 4NCP") allocator as modified slightly to comply with Section 393.1620.1(1) RSMo.

2) MECG does not oppose the remainder of the Company's proposed cost of service study. To the extent that alternative cost of service models or modifications to the Company's model are proposed by other parties, MECG reserves the right to address such changes in rebuttal testimony.

3) Due to the level of the Company's proposed increase, if the Commission were to award Ameren its proposed revenue requirement increase, the Commission should reject the Company's revenue allocation proposal and assign an equal percentage increase to all classes.

4) If the Commission awards a revenue requirement increase that is lower than that proposed by the Company, MECG recommends the Commission take significant steps to address the above cost rates paid by Small General Service ("SGS"), LGS, SP, and LPS. Specifically, MECG recommends that the Commission allocate the revenue increase using the following steps:

    a. Apply half of the difference between the approved revenue requirement and Ameren's proposed revenue requirement as a reduction to SGS, LGS, SP, LPS, and Company Owned Lighting based on the proportional contribution of each class to the overall revenue neutral shift to cost of service from the Company's proposed cost of service study; and

    b. Apply the remaining half of the difference between the approved revenue requirement and Ameren's proposed revenue requirement on an equal percentage basis to all customer classes.

5) The Commission should require the Company to show all components of bill calculation of Electronic Data Interchange ("EDI") bills.
6) For the purposes of this docket, at the Company's proposed revenue requirement for the LGS and SP classes, MECG recommends that the Commission:
   a. Accept Ameren's proposed customer charges and on-peak and off-peak adjusters for both LGS and SP, and Ameren's proposed Rider B credits and reactive charge for SP;
   b. Increase the summer and winter demand charges for LGS and SP by three times the percent class increases; and
   c. Apply the remaining proposed increase on an equal percentage basis to the summer and winter energy charges.
7) If the Commission awards an increase for these classes that is lower than that proposed by the Company, then the Commission can then take larger steps to address the over-recovery of demand-related costs through energy charges and associated intra-class subsidies. Specifically, the Commission should set the demand charges per MECG's recommendation above and apply the approved reduction in the class revenue requirement by reducing all base rate energy charges on an equal percentage basis.

Q. DOES THE FACT THAT YOU MAY NOT ADDRESS AN ISSUE OR POSITION ADVOCATED BY THE COMPANY INDICATE MECG'S SUPPORT?

A. No. The fact that an issue is not addressed herein or in related filings should not be construed as an endorsement of, agreement with, or consent to any filed position.

General Concerns Regarding Ameren's Proposed Revenue Requirement

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED REVENUE REQUIREMENT INCREASE IN THIS DOCKET?

A. My understanding is that Ameren has requested a revenue increase in this docket of approximately $299 million, or 11.97 percent, based on a test year ending December 31, 2020, with certain pro forma adjustments to include known and measurable items through September 30, 2021. *See* Counsel Filing Letter, page 1 and Schedule 1 – Min. Filing Reqmt. 3(B)1.

Q. HAVE THE COMPANY'S RATES SIGNIFICANTLY INCREASED FOR LARGE USERS OVER THE LAST 13 YEARS?

A. Yes. For example, analysis for FERC Form 1 data shows that between 2008 and 2020, and not inclusive of the increases proposed in the instant docket, Ameren's reported revenue per kWh sold to LGS customers has increased from $0.0563/kWh to $0.0772/kWh, an increase of 37.1 percent. However, as recently as 2018, revenue per kWh sold to LGS customers was 50.3 percent higher than 2008, with relief brought about primarily by the Tax Cuts and Jobs Act. Figure 1 and Exhibit

SWC-2 show the increase in revenue per kWh sold (left axis) and the cumulative percent increase over the period (right axis).

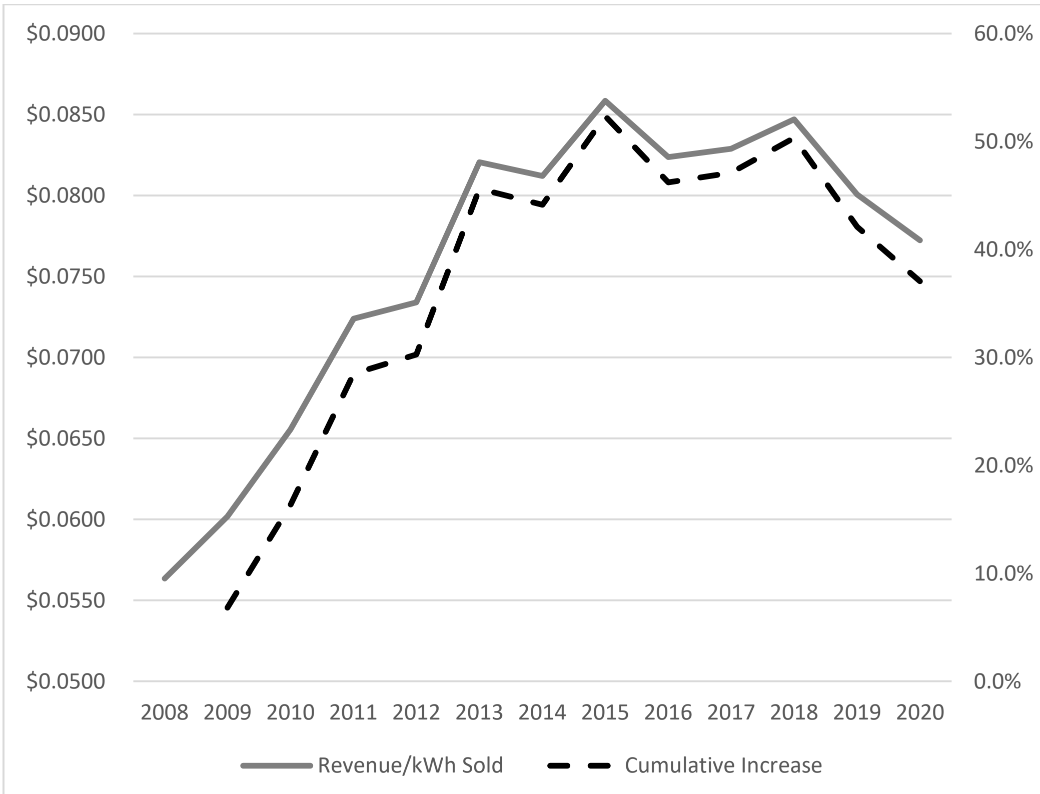

Figure 1. FERC Form 1 Reported LGS Revenue Per kWh Sold and Cumulative Percent Increase, 2008 - 2018. Source: Exhibit SWC-2

Q. HAVE LGS AND SP CUSTOMERS PAID RATES IN EXCESS OF COST OF SERVICE DURING THIS PERIOD AS WELL?

A. Yes. As I will discuss in more detail below, LGS and SP customers have paid rates in excess of cost of service for the time period shown in Figure 1.

Q. PLEASE EXPLAIN.

A. An examination of the revenue neutral[2] results for Ameren rate cases filed since 2007 show that rates for the LGS and SP classes have been set well in excess of cost of service since the 2007 rate case.[3] Table 1 summarizes the Company's final class cost of service study results in each rate case.

Table 1. Summary of Revenue Changes, Per Ameren Cost of Service Study Results, Required to Move LGS and SP to Cost of Service in Previous Ameren Rate Cases.

Rate Case	Revenue Change Required to Move LGS/SP to Cost of Service	
	($)	**(%)**
ER-2007-0002		
LGS	($43,441,000)	-10.2
SP	($8,148,000)	-4.5
ER-2008-0318 (LGS & SP)	($47,863,000)	-7.66
ER-2010-0036 (LGS & SP)	($64,785,000)	-9.74
ER-2011-0028 (LGS & SP)	($63,653,000)	-8.94
ER-2012-0166 (LGS & SP)	($59,937,000)	-7.99
ER-2014-0258 (LGS & SP)	($68,705,063)	-8.54
ER-2016-0179 (LGS & SP)	($26,675,524)	-3.40
ER-2019-0335 (LGS & SP)	($84,130,291)	-10.44

Source: Direct Testimony of Steve W. Chriss, Table 1 and Schedule SWC-3 on behalf of The Midwest Energy Consumers Group, Case No. ER-2019-0335

Q. HAS AMEREN PROPOSED A REVENUE REQUIREMENT CHANGE FOR LGS AND SP CUSTOMERS THAT REFLECTS MOVEMENT TOWARDS THE COST TO SERVE THOSE CUSTOMERS?

A. No. Per Ameren's cost of service study results in this case, at the Company's

[2] Revenue neutral results represent the revenue change for each class necessary to bring that class to its cost of service level per the cost of service study results, as determined prior to any rate change granted to the utility.
[3] Since 2007, the LGS and SP classes have been treated together for purposes of conducting class cost of service studies.

proposed revenue requirement, the LGS and SP classes should receive a 1.4 percent increase. Therefore, even if Ameren is granted the full proposed 11.93 percent rate increase, Ameren's own cost of service study indicates that LGS and SP should receive only a 1.4 percent rate increase. *See* Direct Testimony of Michael W. Harding, page 5, Table 2. However, as I will discuss in more detail below, the Company has proposed an 11.96 percent increase for LGS and an 11.98 percent increase for SP. *Id.,* page 6, Table 3. As such, Ameren is proposing that LGS rates be set approximately $53.5 million above cost of service and that SP rates be set approximately $23.3 million above cost of service. In total, Ameren's proposal would mean that LGS and SP customers together would pay rates that are almost $77 million per year above cost of service levels. *See* Exhibit SWC-3.

Q. SHOULD THE COMMISSION CONSIDER THE IMPACT OF THE PROPOSALS IN THIS DOCKET ON LGS AND SP CUSTOMERS IN SETTING THE CLASS REVENUE REQUIREMENTS AND RATE DESIGNS IN THE IMMEDIATE PROCEEDING?

A. Yes. Electricity represents a significant portion of operating costs for MECG members. When rates increase, that increase in cost puts pressure on the other expenses required by a business to operate. The Commission should consider the impact on customers thoroughly and carefully in their examination of all facets of this case, to ensure that any increase in Ameren's rates is only the minimum amount necessary for the utility to provide adequate and reliable service to each customer class.

Cost of Service and Revenue Allocation

Q. GENERALLY, WHAT IS MECG'S POSITION ON SETTING RATES BASED ON THE UTILITY'S COST OF SERVICE?

A. MECG advocates that rates be set based on the utility's cost of service for each rate class. This produces equitable rates that reflect cost causation, sends proper price signals, and minimizes price distortions.

Production Plant Cost Allocation

Q. WHAT IS YOUR UNDERSTANDING OF THE PURPOSE OF PRODUCTION PLANT FIXED COST ALLOCATION?

A. Production plant cost allocation is the process of allocating to each customer class the fixed costs of a utility's generation assets. Fixed costs are defined as costs that do not vary with the level of output and must be paid even if there is no output.[4]

Q. DO A UTILITY'S FIXED PRODUCTION PLANT COSTS CHANGE WITH CHANGES IN THE AMOUNT OF ELECTRICITY GENERATED?

A. No. The utility's fixed production plant costs do not change with changes in the amount of electricity generated. For example, if a generating unit is not dispatched and produces no energy, the fixed costs are not avoided by the utility or customers. Generation units can be built and operated for different reasons, such as lower fuel costs, or reliability, but the way in which a generation unit is operated does not change

[4] Pindyck, Robert S. and Daniel L. Rubinfeld, "Microeconomics", 5th ed., 2001, page 206.

the fact that the fixed costs are, in fact, fixed, and should be treated as such in the production capacity cost allocation.

Q. IS IT YOUR UNDERSTANDING THAT PRODUCTION PLANT CAPACITY IS SIZED TO MEET THE MAXIMUM DEMAND IMPOSED ON THE SYSTEM BY THE COMPANY'S CUSTOMERS?

A. Yes. It is my understanding that the timing and size of a utility's production plant capacity additions are generally made to meet the maximum demand placed on the utility's system by all customer classes, also known as its coincident peak ("CP"). All of a utility's generation units are needed to meet that demand, and removing any of the units from that stack will limit the utility's ability to do so.

Q. WHY IS IT IMPORTANT FOR THE ALLOCATION OF PRODUCTION PLANT COST TO RECOGNIZE THAT PRODUCTION CAPACITY IS DESIGNED TO MEET SYSTEM PEAK?

A. Basing the allocation of production plant fixed costs on the utility's system peak ensures that the resulting rates reflect cost causation and minimizes cost responsibility shifts between rate classes. Allocation of fixed production plant costs on a variable, or energy, basis can introduce shifts in cost responsibility from lower load factor classes to higher load factor classes. Under an energy allocator, two customer classes can have the same contribution to system peak demand in the test year and cause the Company to incur the same amount of fixed cost to meet that demand, but because one class uses more kWh than the other, that class will pay more of the demand cost than the class that uses fewer kWh. Additionally, use of an energy allocator implies that the generation plant to which that allocator is applied has no fixed cost, which is plainly not the case.

Q. WHAT IS YOUR UNDERSTANDING OF CHANGES IN MISSOURI LAW REGARDING PRODUCTION PLANT COST ALLOCATION?

A. While I am not an attorney, my understanding is that Section 393.1620.2 RSMo states:

"In determining the allocation of an electrical corporation's total revenue requirement in a general rate case, the commission shall only consider class cost of service study results that allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method or one of the methods of assignment or allocation contained within the National Association of Regulatory Utility Commissioners 1992 manual or subsequent manual."

Additionally, Section 393.1620.1(1) RSMo defines "Average and excess method" as:

"…a method for allocation of production plant costs using factors that consider the classes' average demands and excess demands, determined by subtracting the average demands from the noncoincident peak demands, for the four months with the highest system peak loads. The production plant costs are allocated using the class average and excess demands proportionally based on the system load factor, where the system load factor determines the percentage of production plant costs allocated using the average demands, and the remainder of production plant costs are allocated using the excess demands;"

Q. ARE YOU GENERALLY FAMILIAR WITH THE PRODUCTION COST ALLOCATORS INCLUDED IN THE ELECTRIC UTILITY COST ALLOCATION MANUAL PUBLISHED BY THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS IN JANUARY, 1992 ("NARUC MANUAL")?

A. Yes. The NARUC Manual describes 13 production plant allocation methods, as summarized below. In examining the methods, particularly those in which generation resources are assigned operating roles as baseload or peaking resources, it is important to recognize that the NARUC Manual was published in 1992, several years before the Federal Energy Regulatory Commission issued Order 888 in 1996 and Order 2000 in 1999, which enabled the creation of Independent System Operators and Regional Transmission Organizations. The centralized operation of these organizations across broader regions renders a utility-specific assignment of generation resources to roles, and associated production plant cost allocators, less relevant now than they would have been when the NARUC Manual was published.

1) Peak Demand Methods

   a. Single Coincident Peak Method ("1CP"), which allocates production plant costs according to customer class contributions to the utility's highest measured one-hour demand in the test year. *See* NARUC Manual, page 44.

   b. Summer and Winter Peak Method, which, if the summer and winter peaks are close in value, allocates production plant costs according to the average of customer class contributions to those seasonal peaks. *Id.,* page 45.

   c. The Sum of the Twelve Monthly Coincident Peak Method ("12CP"), which, if monthly peaks "lie within a narrow range", allocates production plant costs according to the average of customer class contributions to the CP in each month of the year. *Id.,* page 46.

   d. Multiple Coincident Peak Method, which allocates production plant costs according to the average of customer class contributions to more than one peak, which can represent more than one of the monthly CP, or more than one specified hour across the year, even within a month. *Id.* In my experience, in fully vertically integrated jurisdictions, this methodology uses one or more of the monthly CP, typically focused on the traditional four summer peak months. More generally, the NARUC Manual suggests thresholds for inclusion of five and ten percent of the maximum system peak.

e. All Peak Hours Approach, which allocates production plant costs according to the average of customer class contributions to all defined peak hours. *Id.,* page 47.

2) Energy Weighting Methods

a. A&E, which I will discuss in more detail below, and is suggested by the NARUC Manual as an appropriate method to use if the Commission determines it appropriate to include average demand, which is essentially energy, in production plant cost allocation. *Id.,* page 49.

b. Equivalent Peaker Method, which is based on generation planning and designates generation units as either demand (peaking) or energy (baseload), or some mix thereof, to determine the percent of production plant costs that are to be allocated to the customer classes based on demand and energy. The NARUC Manual notes that this method ignores the relative fuel costs and savings that can occur with different generation types. *Id.,* page 52 to page 55.

c. Base and Peak Method, which is similar to the Equivalent Peaker Method, but assigns the energy portion of production plant cost based on class contributions to on-peak energy usage. *Id.,* page 55 to page 56.

d. Judgmental Energy Weightings, which is essentially a catch all for the Peak and Average Demand methodology, which the Commission has previously rejected as it "has the effect of double counting average demand,"[5] and the 12CP and 1/13th Average Demand methodology, which in my experience has only been used at the Florida Public Service Commission. *Id.,* page 57.

3) Time-Differentiated Embedded Cost of Service Methods

a. Production Stacking Methods, which, similarly to the Equivalent Peaker Method, designate certain generation resources as baseload to be allocated on an energy basis, with remaining generation to be allocated on a demand basis. *Id.,* page 59 to page 60.

b. Base-Intermediate-Peak Method, which assigns generation resources to peak hours, secondary peak, or intermediate, hours, and baseload hours. Costs for peak resources would then be allocated per a CP allocator, for intermediate resources would be allocated per class contributions to the intermediate period, and for baseload resources would be allocated per an energy allocator. *Id.,* page 60 to page 62.

c. Loss of Load Probability ("LOLP") Production Cost Method, in which hourly

[5] *See* File No. ER-2014-0258, Report and Order, April 29, 2015, page 71.

LOLPs are calculated and the hours grouped into on-peak, off-peak, and shoulder periods. Production plant costs are allocated to rating periods according to the relative proportions of LOLPs occurring in each, and then allocated to classes using the allocators determined to be appropriate for each rating period. *Id.,* page 62.

d. Probability of Dispatch Method, which analyzes the hourly load curve for the utility and the generation resources normally used to serve each hourly load. The annual revenue requirement of each generation resource is then divided by the number of hours it operates in the year to create a "per hour cost." The per hour costs are then allocated to classes according to class energy usage in each hour. *Id.*

Q. WHAT IS YOUR UNDERSTANDING OF THE PRODUCTION COST ALLOCATOR PROPOSED BY AMEREN IN THIS DOCKET?

A. My understanding is that Ameren proposes an A&E allocator based on the four non-coincident peaks ("NCP") for each customer class, or A&E 4NCP. The Company proposes to use the four NCP for each customer class regardless of when during the year those NCP occurred, and those four NCP are averaged in the calculation of the allocator. Additionally, the Company proposes to manually adjust the Lighting Classes to recognize that the classes tend to peak during off-peak winter periods. *See* Direct Testimony of Thomas Hickman, page 14, line 18 to page 15, line 6.

Q. WHAT IS YOUR UNDERSTANDING OF AN A&E ALLOCATOR?

A. An A&E allocator is an allocator that recognizes the contribution of each class to the utility's average demand, which is total annual kWh divided by 8,760 hours in a typical year, as well as the relative peak demand of each class. As such, A&E is a methodology often used when a Commission determines that production plants are used to provide energy as well as peak demand. However, the A&E allocator differs from other allocators that have an energy component in that it does not double count the energy portion of the allocator, as is the case with the Peak and Average allocator as discussed above. Additionally, the A&E allocator does not rely on fixed subjective resource weightings that are incompatible with the flexible nature of regional transmission organization dispatch of generation, as is the case with the Base-Intermediate-Peak allocator. As such, even with its use of energy as part of the allocator, the A&E allocator is, in my experience, an objective, transparent, and reasonable production plant cost allocator.

Mechanically, the CP or NCP peak demand value for each class – in Ameren's case, 4NCP – is subdivided into average demand and excess demand. The average demand, or energy portion for each class, is weighted by the system load factor. The excess demand portion, which is the difference between the average demand and the peak demand for each class, is weighted by 1 minus the system load factor. As a result, as system load factor increases and the system gets less peaky, the overall weighting of the average demand portion of the allocator increases, and conversely, as the system load factor decreases and the system gets more peaky, the overall weighting of the excess demand portion of the allocator increases. At a theoretical maximum of 100 percent system load factor, the A&E allocator is essentially an energy allocator.

Q. HAVE YOU EXAMINED THE COMPANY'S PROPOSED A&E 4NCP ALLOCATOR?

A. Yes. Upon examination of the calculation of Ameren's proposed allocator, it appears that allocator differs slightly from that specified in Section 393.1620.1(1) RSMo, in that the months used for the 4NCP in the A&E 4NCP are "determined…for the *four months with the highest system peak loads*." As shown in Exhibit SWC-4 row (9), the four months with the highest system peak loads are February, June, July, and August, but in rows (10) through (14) the class NCPs used for the calculation of the allocator are, depending on the class, from January, March, April, May, June, July, August, and September.

Q. HAVE YOU CALCULATED THE 4NCP A&E PER THE LANGUAGE IN SECTION 393.1620.1(1) RSMo?

A. Yes, as shown in Exhibit SWC-5. This calculation uses the class NCPs from the four months with the highest system peak loads (February, June, July, and August), and also accepts Ameren's lighting proposal and the Company's use of a single CP for the calculation of the system load factor. As shown in Table 2, the difference in outcomes is relatively small, with the largest changes being an addition of 0.24 percent to Residential and a reduction of 0.25 percent to LPS.

Table 2. Comparison of Ameren Proposed and Section 393.1620.1(1) RSMo A&E 4NCP Results.

Customer Class	Ameren Proposed A&E 4NCP (%)	Per 393.1620.1(1) A&E 4NCP (%)	Difference (%)
Residential	52.53	52.76	+0.24
SGS	10.93	10.89	-0.03
LGS/SP	28.71	28.77	+0.05
LPS	7.50	7.24	-0.25
Lighting	0.34	0.33	-0.01

Source: Exhibit SWC-5

Q. HAVE YOU CALCULATED ALLOCATORS FOR OTHER PRODUCTION PLANT COST ALLOCATION METHODS INCLUDED IN THE NARUC MANUAL THAT MECG BELIEVES ARE ALSO REASONABLE?

A. Yes. Based on the discussions above regarding the nature of production plant costs and allocators included in the NARUC Manual and an examination of Ameren's system peaks from their proposed test year data, it would be reasonable to allocate production plant costs on a 1CP basis or multiple CP basis at either five or ten percent of maximum system peak.

Q. BASED ON YOUR ANALYSIS, HOW MANY CPS SHOULD BE INCLUDED IN THE TWO MULTIPLE CP ALLOCATORS?

A. Based on my analysis of Ameren's monthly peaks for the test year, a multiple CP production plant cost allocator should use a 2CP based on the system peaks in July and August at the five percent of maximum system peak level and a 3CP based on the system peaks in June, July, and August at the 10 percent of maximum system peak level. *See* Figure 2.

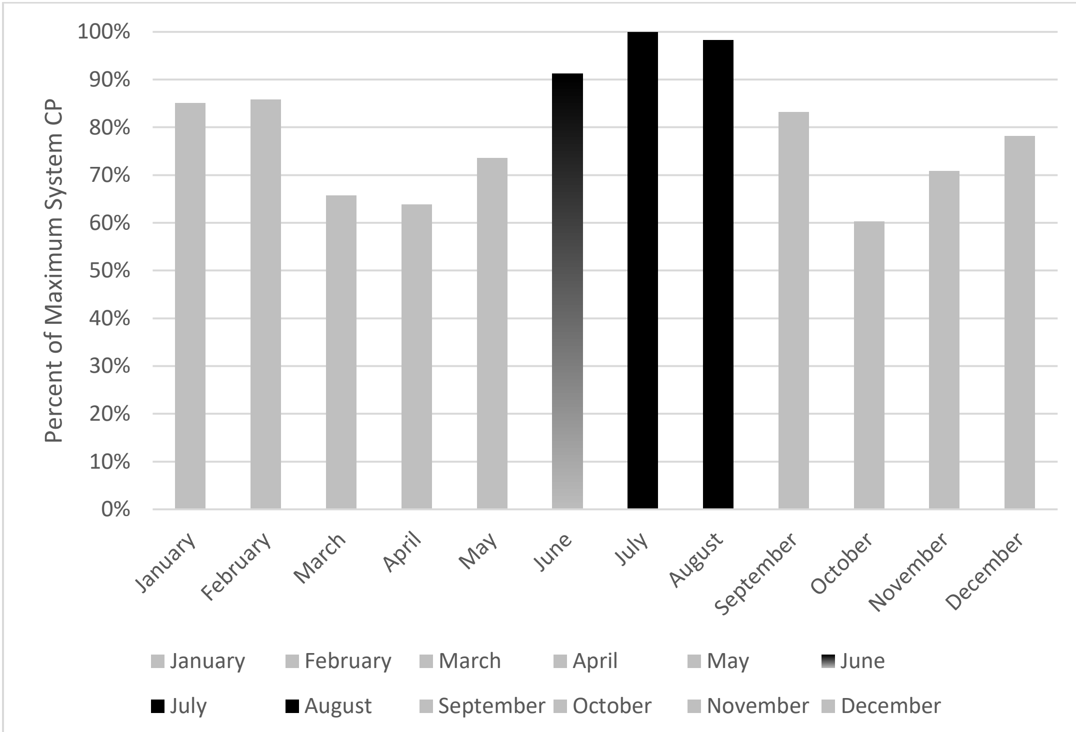

Figure 2. Ameren Monthly System CP as a Percentage of Maximum System CP. Source: Exhibit SWC-6

Q. WHAT ARE THE RESULTING REASONABLE CP-BASED ALLOCATORS BASED ON AMEREN'S PROPOSED TEST YEAR DATA?

A. The resulting reasonable CP-based allocators are shown in Table 3 along with the Ameren Proposed and Section 393.1620.1(1) 4NCP allocators for comparison purposes. One notable difference between the CP-based allocators and the A&E allocators is that a portion of production plant cost is allocated to Lighting by the A&E allocators.

Table 3. Comparison of CP-Based Allocators with Ameren Proposed and Section 393.1620.1(1) A&E 4NCP Results.

Customer Class	1CP (%)	2CP @ 5% of Max (%)	3CP @ 10% of Max (%)	Per Section 393.1620.1(1) A&E 4NCP (%)	Ameren Proposed A&E 4NCP (%)
Residential	53.34	53.36	53.08	52.76	52.53
SGS	10.86	10.85	10.79	10.89	10.93
LGS/SP	28.56	28.36	28.52	28.77	28.71
LPS	7.23	7.42	7.61	7.24	7.50
Lighting	0.00	0.00	0.00	0.33	0.34

Sources: Exhibits SWC-5 and SWC-6

Q. WHAT IS MECG'S RECOMMENDATION TO THE COMMISSION ON THIS ISSUE?

A. For the purposes of this docket, MECG supports the allocation of production plant cost using the Company's proposed A&E 4NCP allocator as modified slightly to comply with Section 393.1620.1(1) RSMo. MECG believes that the A&E 4NCP methodology is reasonable, and for commercial and industrial customers, the results of the Company's proposed allocator are generally similar to the reasonable CP-based allocators calculated above.

Revenue Allocation

Q. HOW DOES THE COMPANY REPRESENT WHETHER RATES FOR A CUSTOMER CLASS ACCURATELY REFLECT THE UNDERLYING COST OF SERVICE?

A. The Company represents this relationship in its cost of service study results through the use of class-specific rates of return. *See* Schedule TH-D1. These rates of return can be converted into a rate of return index ("RRI"), which is an indexed measure of the relationship of the rate of return for an individual rate class to the total system rate of return. An RRI greater than 1.0 means that the rate class is paying rates in excess of the costs incurred to serve that class, and an RRI less than 1.0 means that the rate class is paying rates less than the costs incurred to serve that class. As such, those rate classes with an RRI greater than 1.0 shoulder some of the revenue responsibility for the classes with an RRI less than 1.0.

Q. HAVE YOU CALCULATED A RRI FOR EACH CUSTOMER CLASS BASED ON AMEREN'S COST OF SERVICE RESULTS?[6]

A. Yes, as shown in Table 4 below.

Table 4. Rate of Return Index, Ameren Proposed Cost of Service Study Results.

Customer Class	Rate of Return (%)	RRI
Residential	3.10	0.65
Small General Service	5.15	1.08
Large General Service/Small Primary Service	7.35	1.54
Large Primary Service	7.70	1.62
Company Owned Lighting	9.02	1.89
Customer Owned Lighting	-4.57	(0.96)

Sources: Exhibit SWC-7 and Schedule TH-D1

Q. DO THE RATES FOR THE LGS AND SP CLASSES PROVIDE A RATE OF RETURN FOR THE COMPANY IN EXCESS OF THEIR COST OF SERVICE LEVELS?

A. Yes. As shown in Table 4, Ameren's cost of service results show that LGS and SP, with an RRI of 1.54, provide a rate of return significantly above the cost of service

[6] The slight modification to Ameren's A&E methodology discussed above would not materially change the rate of return index calculated for each class.

level for the class. Additionally, SGS, LPS, and Company Owned Lighting are also paying rates in excess of their respective cost of service levels, though SGS is much closer to cost of service than the other rate classes.

Q. HAVE LGS AND SP RATES PROVIDED A RATE OF RETURN ABOVE THEIR COST OF SERVICE LEVELS SINCE THE COMPANY'S 2007 RATE CASE?

A. Yes. As shown in Table 5, LGS and SP rates have provided a rate of return above their cost of service levels in every rate case back to and including the Company's 2007 rate case. In total, as shown in Table 1 earlier in this testimony, this has resulted in LGS and SP customers paying rates well in excess of the Company's cost to serve them since 2007.[7] As such, rate relief is long overdue.

Table 5. LGS/SP Rate of Return, Ameren Cost of Service Study Results, Past Rate Cases.

Case	LGS/SP Rate of Return (%)	Total Missouri Rate of Return (%)	Rate of Return Index Value
ER-2007-0002 (LGS)	5.86	2.74	2.14
ER-2007-0002 (SP)	4.47	2.74	1.63
ER-2008-0318	7.01	4.06	1.73
ER-2010-0036	6.12	1.89	3.24
ER-2011-0028	8.26	4.59	1.80
ER-2012-0166	6.32	2.89	2.19
ER-2014-0258	7.57	4.44	1.71
ER-2016-0179	9.73	5.41	1.80
ER-2019-0335	11.35	7.37	1.54
Present Case	7.35	4.76	1.54

Source: Table 4, Direct Testimony of Steve W. Chriss, Table 3, on behalf of The Midwest Energy Consumers Group, Case No. ER-2019-0335

[7] Prior to 2007 Ameren had not had a general rate case for approximately 20 years.

Q. HAS THE COMPANY CALCULATED THE REVENUE NEUTRAL[8] REVENUE CHANGES REQUIRED TO BRING EACH CLASS TO COST OF SERVICE PER THE COMPANY'S COST OF SERVICE STUDY IN THIS CASE?

A. Yes, as shown in Table 6.

Table 6. Revenue Neutral Shift Results, Ameren Proposed Cost of Service Study.

Customer Class	Revenue Neutral Shift ($000)	(%)
Residential	$93,202	7.32
Small General Service	($4,258)	-1.55
Large General Service/Small Primary Service	($66,501)	-9.14
Large Primary Service	($17,855)	-9.47
Company Owned Lighting	($6,183)	-17.35
Customer Owned Lighting	$1,594	55.96

Source: CCOS Spreadsheet, tab SCH 1

For LGS and SP specifically, the revenue neutral change required is a reduction of approximately $66.5 million.

Q. DOES THE COMPANY STATE THAT EQUAL RATES OF RETURN FOR EACH CLASS ARE AN APPROPRIATE STARTING POINT WHEN DESIGNING RATES?

A. Yes. The Company states that equal rates of return (i.e., rates set at cost of service) for all customer classes are an appropriate starting point for designing rates for three reasons:

1) Equity and fairness to all electric customers;

[8] Revenue neutral refers to the changes necessary to bring each class to cost of service assuming no overall change in the utility's revenues.

2) Encouraging cost-effective utilization of electricity; and
3) Competition, in that cost-based electric rates permit the Company to compete with alternative fuels, co-generation, and other electric providers for new commercial and industrial customers. *See* Direct Testimony of Michael W. Harding, page 3, line 13 to page 4, line 10.

Q. HAS THE COMPANY STATED IN THE PAST THE ROLE OF A REGULATOR RELATIVE TO COST OF SERVICE IN THE SETTING OF RATES?

A. Yes. In Case No. EC-2014-0224, Ameren witness Terry M. Jarrett states that "[t]he regulator's job is to make sure the rates are fair according to the cost of service for each class." *See* Case No. EC-2014-0224, Rebuttal Testimony of Terry M. Jarrett, page 6, line 9 to line 10.

Q. WHAT IS YOUR UNDERSTANDING OF AMEREN'S PROPOSED REVENUE ALLOCATION IN THIS CASE?

A. My understanding is that Ameren has put forth a two-step revenue allocation proposal:

1) Increase or decrease current base retail revenues on a revenue neutral basis for the two Lighting classes; and
2) Allocate the increase or decrease on an equal percentage basis after any potential revenue neutral adjustments in step 1. *See* Direct Testimony of Michael W. Harding, page 5, line 8 to page 6, line 2.

Q. IS THE COMPANY'S PROPOSAL EFFECTIVELY AN EQUAL PERCENTAGE INCREASE FOR ALL CUSTOMER CLASSES WITH THE EXCEPTION OF CUSTOMER-OWNED LIGHTING?

A. Yes, Ameren's proposal is effectively an equal percent increase as all classes, with the exception of Customer-Owned Lighting, are proposed to receive increases between 11.80 percent and 11.99 percent, versus an average increase of 11.93 percent. *See* Direct Testimony of Michael W. Harding, page 6, Table 3.

Q. HOW DOES THE COMPANY CHARACTERIZE ITS REVENUE ALLOCATION PROPOSAL?

A. The Company characterizes its revenue allocation proposal as "a modest departure from establishing class revenue requirements on the basis of equal class rates of return as shown in its CCOSS." *Id.,* page 5, line 4 to line 5. This characterization is, at best, a complete misrepresentation of the Company's proposal, which not only departs from establishing class revenue requirements on the basis of equal class rates of return, but charges headlong to move rates further from cost-based levels. As an example, the Company actually proposes an above average increase for both LGS and SP – 11.96 percent and 11.98 percent, respectively. This proposed increase is greater than the 11.93 percent system average increase counter to their own evidence that supports a 1.4 percent cost-based increase and moves LGS and SP further from cost-based rates. *Id.,* page 6, Table 3.

Q. WHAT IS MECG'S RECOMMENDATION TO THE COMMISSION IF THE COMMISSION WERE TO AWARD AMEREN ITS PROPOSED REVENUE REQUIREMENT INCREASE?

A. Due to the level of the Company's proposed increase, if the Commission were to award Ameren its proposed revenue requirement increase, the Commission should reject the Company's revenue allocation proposal and assign an equal percentage increase to all classes.

Q. WHAT IS MECG'S RECOMMENDATION TO THE COMMISSION IF THE COMMISSION AWARDS A REVENUE REQUIREMENT DECREASE LOWER THAN THAT PROPOSED BY THE COMPANY?

A. If the Commission awards a revenue requirement increase lower than that proposed by the Company, MECG recommends the Commission take significant steps to bring the rates paid by SGS, LGS, SP, and LPS closer to their cost of service-based levels. Specifically, MECG recommends that the Commission allocate the revenue increase using the following steps:

1) Apply half of the difference between the approved revenue requirement and Ameren's proposed revenue requirement as a reduction to SGS, LGS, SP, LPS, and Company Owned Lighting based on the proportional contribution of each class to the overall revenue neutral shift to cost of service from the Company's proposed cost of service study; and

2) Apply the remaining half of the difference between the approved revenue requirement and Ameren's proposed revenue requirement on an equal percentage basis to all customer classes.

Q. PLEASE PROVIDE AN ILLUSTRATIVE EXAMPLE.

A. Commission Staff has proposed a revenue requirement increase of approximately $221 million in this case, which is a reduction from the Company's proposed revenue requirement of approximately $77 million. *See* Direct Testimony of Lisa M. Ferguson, page 10, line 16. As shown in Exhibit SWC-8 and Table 7, the proposed allocation methodology, at a reduction of $77 million, provides for rate relief for all customer classes while using the revenue requirement reduction to provide approximately a 41 percent movement towards cost of service-based rates for SGS, LGS, SP, LPS, and Company-Owned Lighting.

Table 7. Results of MECG Revenue Allocation Proposal, $77 Million Reduction per Staff Proposed Revenue Requirement.

Customer Class	Revenue Change ($)	Revenue Change (%)	Subsidy Reduction (%)
Residential	$131,951,362	10.4	
Small General Service	$26,743,055	9.8	41
Large General Service	$34,010,216	6.7	41
Small Primary Service	$14,812,832	6.7	41
Large Primary Service	$12,351,893	6.6	41
Company Owned Lighting	$1,144,501	3.2	41

Source: Exhibit SWC-8

LGS and SP Rate Design

Q. WHAT IS YOUR UNDERSTANDING OF THE CHARGES INCLUDED IN THE CURRENT LGS RATE DESIGN?

A. My understanding is that the LGS rate design is, in my experience, a relatively complex rate structure, and composed of the following charges:

1) Summer and winter customer charges, which are a $/month charge, the level of which does not vary by season;

2) Summer and winter demand charges, which are a $/kW charge based on "total billing demand," which is determined as the maximum demand during the billing period, but no less than 100 kW;

3) Summer energy charges, which are a set of declining block hours-use $/kWh charges based on the customer's load factor for the billing month using the total billing demand for the month. There are three blocks built into the energy charges. The break-point for the first block is 150 kWh/kW of billing demand, and the break-point for the second block is 350 kWh/kW of billing demand;

4) Winter energy charges, which are a set of declining block hours-use $/kWh charges based on the customer's "base billing demand" for the winter month, which is the lesser of the total billing demand for the month or the maximum of the total billing demand for the customer for the preceding May, June, July, August, September, or October. There are three blocks built

into the energy charges. The break-point for the first block is 150 kWh/kW of base billing demand, and the break-point for the second block is 350 kWh/kW of base billing demand;

5) Winter seasonal energy charge, which is a $/kWh charge applied to energy usage related to "seasonal billing demand," which is the portion of total billing demand in excess of base billing demand; and

6) Low income pilot program charge, which is a $/month charge. *See* MO P.S.C. Schedule 6, 4th Revised, Sheet No. 56.

Q. DOES THE COMPANY DEFINE WHEN THE SUMMER AND WINTER RATES ARE APPLICABLE?

A. Yes. In the tariff, the Company defines summer rates as being applicable during the four monthly billing periods of June through September, and winter rates as being applicable during the eight monthly billing periods of October through May. *Id.*

Q. WHAT IS YOUR UNDERSTANDING OF THE STRUCTURE OF THE BASE CHARGES INCLUDED IN THE CURRENT SP RATE DESIGN?

A. My understanding is that the structure of the base charges included in the current SP rate design are largely identical to those in the current LGS rate design, with the addition of reactive charges assessed on a $/kVar basis. Additionally, total billing demand is determined as the maximum demand during peak hours or 50 percent of the maximum demand established during off-peak hours, and in no event less than 100 kW. *See* MO P.S.C. Schedule No. 6, 4th Revised, Sheet No. 57.

Q. WHAT IS YOUR UNDERSTANDING OF HOW THE COMPANY PROPOSES TO APPLY THE REVENUE REQUIREMENT INCREASE TO THE CHARGES CONTAINED IN THE LGS AND SP SCHEDULES?

A. My understanding is that the Company proposes to apply the proposed revenue requirement increase to the charges contained in the LGS and SP schedules on an equal percentage basis, with two exceptions. Due to the rollout of advanced metering that eliminated the need for incremental metering for Time-of-Day customers, the Company proposes to equalize the customer charge for SGS, LGS, SPS, and LPS customers that choose the Time-of-Day option with the customer charge for non-Time-of-Day customers. Additionally, the Company proposes to set the monthly customer charge, Rider B credits, and Reactive charge the same for both SP and LPS. *See* Direct Thomas of Michael W. Harding, page 11, line 3 to line 19.

Q. DO THE COMPANY'S EDI BILLS, SUCH AS THOSE RECEIVED BY A CUSTOMER LIKE WALMART, TRANSPARENTLY COMMUNICATE LGS CUSTOMER USAGE AND THE BASE RATE CHARGES ASSESSED?

A. No. While the Company's EDI bills do provide a line item for each charge detailing the billing determinants and rate, there is no indication of "base billing demand" or "seasonal billing demand" on winter bills that are used to assess the seasonal energy charge on a portion of usage. An example of the impact of this lack of information on the bill is that, for winter bills, there is no direct method by which a customer could calculate their energy block usages and verify that their billed charges are correct.

Q. DO YOU PROVIDE AN EXAMPLE OF THE INFORMATION RECEIVED BY A LGS CUSTOMER FROM THE COMPANY THROUGH AN EDI BILL?

A. Yes. Exhibit SWC-9 is the LGS portion of an EDI bill received by Walmart billed on winter rates[9].

Q. SHOULD THE COMMISSION REQUIRE AMEREN TO SHOW ALL COMPONENTS OF BILL CALCULATION ON EDI BILLS?

A. Yes.

Q. DOES MECG HAVE CONCERNS WITH THE COMPANY'S RATE DESIGN PROPOSALS FOR THE LGS AND SP CLASSES?

A. Yes. MECG's concerns with the rate design proposals for the LGS and SP classes are:

1) LGS and SP rates do not currently reflect the underlying cost of serving those classes. That is to say that demand charges do not collect all demand-related costs. Instead a significant portion of these demand-related costs are collected on a variable basis through the energy charges;

2) As a result, LGS and SP rates shift cost responsibility within the rate classes in that they charge customers for demand-related (i.e., fixed) costs through energy (i.e., variable) charges; and

[9] The remainder of the bill contains natural gas charges, which are not relevant to the instant docket and have been redacted.

3) The hours-use energy charge structure is not the most simple and transparent means to communicate energy and demand price signals and can unduly discriminate between customers who pursue actions that change their energy consumption, such as through energy efficiency or conservation.

Q. WHAT IS YOUR UNDERSTANDING OF THE COST OF SERVICE STUDY RESULTS FOR LGS AND SP?

A. My understanding is that Ameren incurs three types of costs to serve LGS and SP customers: Customer, Demand, and Energy. Demand costs are fixed costs incurred by the Company to size the system such that it can meet the peak kW demands imposed by the rate class and do not change with changes in how many kWh of energy are consumed by customers. Customer costs are also fixed costs, which are incurred based on the number of customers served by the Company, and do not vary by the size of each customer or how much energy the customers consume. Given that both the demand and customer costs are fixed, they should not be collected through a variable energy charge. In contrast, energy costs are variable costs incurred by the Company in relation to the amount of energy consumed by customers. In order to send proper price signals, energy charges should only be used to collect variable costs like fuel.

Q. ARE THE MAJORITY OF COSTS INCURRED TO SERVE LGS AND SP CUSTOMERS DEMAND-RELATED?

A. Yes. *See* Table 8 below. Per Ameren's cost of service study, approximately 77 percent of the costs incurred by the Company to serve LGS and SP customers are demand-related while only approximately 21 percent are energy related. That said, while 77% of costs are demand-related, only 14% of LGS revenues and 9.6% of SP revenues are collected through demand costs. Further demonstrating this problem, while 20.8% of LGS / SP costs are energy related, 83.6% of LGS revenues and 89.3% of SP revenues are collected through energy charges. Clearly then LGS and SP rate components are sending incorrect price signals. Specifically, charges for these classes suggest to customers that energy costs are higher than they actually are and that demand costs are lower than they are.

Table 8. LGS and SP Cost of Service Study Results, Equalized Rate of Return vs. Proposed LGS and SP Revenue Requirements.

Component	COSS Results		LGS Revenue Requirement		SP Revenue Requirement	
	($000)	(% of Total)	($000)	(% of Total)	($)	(% of Total)
Demand	$565,531	76.7	$79,558	14.0	$23,625	9.6
Energy	$153,373	20.8	$474,667	83.6	$220,289	89.3
Customer	$18,762	2.5	$13,563	2.4	$2,903	1.2
Total	**$737,666**	**100**	**$562,180**	**100**	**$243,913**	**100**

Source: Exhibit SWC-10

Q. HOW DOES AMEREN PROPOSE TO COLLECT THE LGS AND SP REVENUE REQUIREMENTS THROUGH THE PROPOSED RATE DESIGNS?

A. Contrary to the results of its cost of service study, Ameren proposes to inappropriately collect the majority of LGS and SP revenue requirements through the energy charges, as opposed to setting all charges to reflect the underlying cost of service study results and assigning customer, demand, and energy costs to their respective charges.

Q. PLEASE EXPLAIN.

A. As described above, both the LGS and SP rate schedules utilize three-block "hours-use" rate structures for the energy charges, which set the billing kWh for each block based on the kWh used for each kW of billing demand, or load factor for the billing month. One rate is charged for the first 150 kWh used per kW of billing demand, a second lower rate is charged for the next 200 kWh used per kW of billing demand, and all additional kWh are charged the lowest third block rate. As shown in Table 8, for the LGS class, this proposed rate design would collect approximately 84 percent of non-energy efficiency base rate revenues through energy charges and approximately 14 percent of revenues through demand charges. For the SP class, the proposed rate design would collect approximately 89 percent of non-energy efficiency base rate revenues through energy charges and approximately 9.6 percent through demand charges.

Q. WHICH OF THE COMPANY'S FUNCTIONAL COSTS SHOULD BE RECOVERED THROUGH DEMAND CHARGES?

A. All of the Company's production demand (capacity), transmission, and distribution demand costs should be recovered through demand charges. These costs are fixed and incurred to serve customer kW demands on the system regardless of how many kWh are consumed. Optimally the costs for each of the three functions would be recovered through its own unbundled demand charge (or charges if time or seasonal differentiation is appropriate) to best recover costs in a manner that reflects how those costs are incurred and allocated.

Q. IS THE COLLECTION OF DEMAND-RELATED COSTS THROUGH AN ENERGY CHARGE CONSISTENT WITH THE COMPANY'S CLASSIFICATION AND ALLOCATION OF DEMAND-RELATED COSTS?

A. No. In its class cost of service study, the Company does not classify or allocate any of its demand-related costs on an energy basis. Rather, these costs are incurred, and therefore classified, based on customer demand or number of customers. Costs should be collected in a manner which reflects how they are incurred. As such, collecting demand-related (fixed) costs through an energy (variable) charge violates cost causation principles.

Q. DOES THE RECOVERY OF DEMAND-RELATED COSTS THROUGH AN ENERGY CHARGE DISADVANTAGE HIGHER LOAD FACTOR CUSTOMERS?

A. Yes. The shift in demand-related costs from per kW demand charges to per kWh energy charges results in a shift in demand cost responsibility from lower load factor customers to higher load factor customers. This results in a misallocation of cost responsibility as higher load factor customers overpay for the demand-related costs incurred by the Company to serve them. In other words, higher load factor customers are paying for a portion of the demand-related costs that are incurred to serve the lower load factor customers simply because of the manner in which the Company collects those costs in rates.

Q. DO THE COMPANY'S PROPOSED DEMAND CHARGES COVER THE COST OF DISTRIBUTION AND TRANSMISSION SERVICE?

A. No, they do not. At the Company's proposed revenue requirement, the estimated year-round cost-based transmission and distribution charge for LGS would be $6.05/kW. *See* Exhibit SWC-13. In comparison, Ameren's proposed total demand charges are $6.04/kW for summer months and $2.24/kW for winter months. *See* Exhibit SWC-11.

Q. WOULD THE PROPER COLLECTION OF DEMAND-RELATED (FIXED) COSTS THROUGH A DEMAND CHARGE PROVIDE BENEFITS TO THE COMPANY?

A. Yes. By collecting a large percentage of a class revenue requirement through energy charges, the Company subjects itself to under and overcollection of its revenue requirement due to fluctuations in customer usage. As such, issues such as weather and the economy will have a greater impact on the utility versus a rate design in which an appropriate amount of revenue requirement is collected through the demand charge.

Q. DOES THE HOURS-USE RATE STRUCTURE, WITH DECLINING ENERGY RATES AS LOAD FACTOR INCREASES, ADDRESS SOME OF THE SHIFT IN COST RESPONSIBILITY?

A. Upon examination it does not appear that the hours-use structure addresses the shift in cost responsibility. On its face, the hours-use structure should benefit higher load factor customers as the energy rates decline as a customer moves through the declining energy blocks.[10] Additionally, as a customer's load factor increases the billed cost per kWh can decrease as the customer and demand charge portions of the bill are spread over more kWh. However, in the face of rate designs that ignore cost of service study results, these purported benefits are largely illusory.

To understand the underlying responsibility for demand costs – that is, which customers are paying for demand costs incurred by the Company and how much they are paying for it – it is important to look at the underlying demand cost recovery on a $/kW basis – the same basis upon which demand-related costs are incurred. To do so, the cost of service-based demand and energy charges must be calculated.

Q. HAVE YOU ESTIMATED A COST OF SERVICE-BASED DEMAND AND ENERGY CHARGES FOR LGS AT THE COMPANY'S PROPOSED REVENUE REQUIREMENT?

A. Yes. Assuming the demand charge recovers 76.7 percent of base rate revenues, consistent with the Company's cost of service study results, the estimated cost of service-based $/kW demand charge for LGS for the summer period would be $27.42/kW and for the winter period would be $15.22/kW. Additionally, the cost of service-based energy charge for the summer period is $0.02228/kWh and for the winter period is $0.01316/kWh. *See* Exhibit SWC-14.

[10] It should be noted that hours-use blocks are additive – a customer in a higher block also pays the respective charges for usage in the earlier blocks.

Q. WHAT IS THE NEXT REQUIRED CALCULATION?

A. The next required calculation is the estimated effective demand cost per kW charged to customers across a range on monthly load factors or hours of use in a typical 720-hour month. The estimated effective demand cost is the sum of fixed costs recovered through the hours-use energy charges plus the demand charge. To isolate the fixed costs recovered through the hours-use energy charges, I subtracted the cost of service-based energy charge from the Company's proposed LGS energy charges for the summer period. For the purposes of the calculation, I assumed that the customer's load, when operating in any hour, is 500 kW. *Id.*

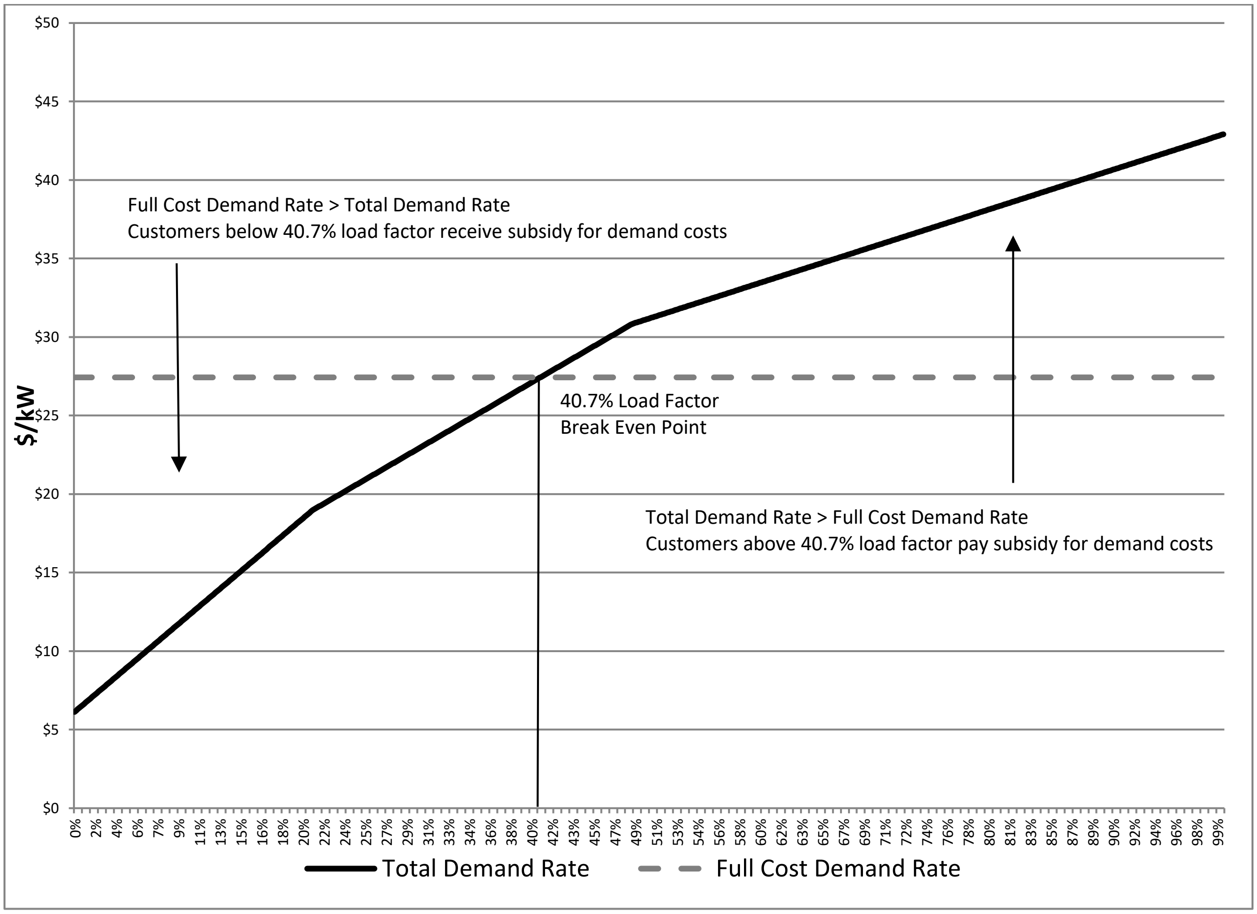

Figure 3. Effective $/kW Charged to Customers by Load Factor, LGS Summer (720 Hour Month)

Q. WHAT DOES YOUR ANALYSIS SHOW?

A. As calculated in Exhibit SWC-14 and shown in Figure 3, as load factor increases, the cost per kW charged to customers for demand-related costs increases. This result is a concern, as the demand-related cost incurred to serve a customer *does not change* with the customer's load factor, and, like an increase in per kWh energy consumption, an increase in load factor should not result in an increase in the demand-related cost per kW charged to that customer. This design does not reward the more efficient utilization of the Company's facilities and instead just shifts costs responsibility within the customer class. When compared to the cost of service-based demand charge, a number of customers would not just be effectively charged a higher rate for demand-related costs, but would be charged a rate that exceeds the cost of service-based level.

Q. IN YOUR OPINION, IS THE HOURS-USE STRUCTURE THE MOST SIMPLE AND TRANSPARENT MANNER IN WHICH TO COMMUNICATE ENERGY AND DEMAND PRICE SIGNALS?

A. No. The hours-use structure is not the simplest manner as it requires the analyst to have more than a surface level understanding of the rate structure in order to understand the interplay of the energy rates and load factor, which is needed to perform bill analyses.

Q. HAVE YOU CREATED AN ILLUSTRATIVE BILL ANALYSIS OF LGS RATES TO DEMONSTRATE THIS COMPLEXITY ?

A. Yes, as shown in Exhibit SWC-15, which demonstrates a bill analysis for a summer month, and Exhibit SWC-16, which demonstrates a bill analysis for a winter month.

Q. DOES A BILL ANALYSIS OF LGS RATES REQUIRE SEVERAL STEPS SIMPLY TO DETERMINE WHAT KW DEMAND AND KWH USAGES ARE USED TO CALCULATE COST?

A. Yes. As shown in Exhibit SWC-15, for summer months, identifying the kW demand is straightforward, but calculating the kWh to be used in each of the three blocks requires three sets of calculations.

Q. IS THE DETERMINATION OF THE KW DEMAND AND KWH USAGES USED TO CALCULATE COST IN WINTER MONTHS EVEN MORE COMPLEX?

A. Yes. As shown in Exhibit SWC-16, determining the applicable kW demands for winter bills requires analyzing the billing demands from the previous May, October, and summer month with the highest demand, in addition to the billing period kW, to determine the lowest of the four demands. That amount is then compared to the billing period kW to determine the seasonal demand and seasonal energy, and those amounts then inform the kW demand and kWh energy amounts to be processed through the blocking exercise. As noted above, winter bills do not include the additional demands, so validation of the analysis is extremely difficult.

Q. CAN THE HOURS-USE STRUCTURE UNDULY DISCRIMINATE BETWEEN CUSTOMERS WHO INSTALL ENERGY EFFICIENCY MEASURES?

A. Yes, and this can be shown with a simple example. Assume two customers have the same monthly billing demand. One of the customers has a load factor of 40 percent and the other has a load factor of 70 percent. Both customers install the same energy efficiency measure that operates in the same manner and at the same time for both customers, and that measure has no effect on the monthly billing demand. Using Ameren's proposed LGS summer rates, the customer with the 40 percent load factor will save 8.16 cents/kWh while the customer with the 70 percent load factor will save only 5.49 cents/kWh, even though the energy efficiency measure for each had the same impact on customer usage and the utility's system. It should also be noted that some of the incremental amount of savings is attributable to demand-related costs collected through the energy charges, even though the customer did not actually reduce demand on the system. This is neither a cost-based nor equitable result.

Q. IS AMEREN CURRENTLY DEPLOYING AMI?

A. Yes. *See* Direct Testimony of Warren Wood, page 5, line 8 to line 11.

Q. HAS THE COMPANY IN THE PAST DELINEATED THE BENEFITS OF AMI AS IT RELATES TO RATES?

A. Yes. In ER-2019-0335, the Company presented the following benefits of AMI as it relates to rates:

1) AMI meters facilitate the Company's ability to bill more complex rates;
2) AMI data can facilitate analysis of the impact that adoption of different rate structures has on customer bills, enabling more informed customer decision-making about the best rate options;
3) AMI data allows the Company to present customers with more detailed and timely usage information and provide insights regarding new and different ways that customers can change usage to manage their bills and respond to price signals; and
4) Smart devices could potentially leverage price or other signals to automate load shifting to benefit the utility system or reduce customer bills. *See* File No. ER-2019-0335, Direct Testimony of Steven M. Wills, page 11, line 9 to

page 12, line 3.

Q. DOES MECG GENERALLY AGREE WITH THE COMPANY'S STATED BENEFITS?

A. Yes. However, rate designs not based on the utility's cost of service, such as the hours-use rate designs featured in Ameren's current and proposed LGS and SP rate designs, do not best leverage AMI technology, which, with usage visibility, can allow for transparent, cost-based, and actionable time of use rate options. The benefits of AMI are far less likely to be realized by LGS and SP customers without a complete restructuring of those rate schedules.

Q. IN ER-2019-0335, DID THE COMPANY SPECIFY A PREFERRED RATE STRUCTURE AS PART OF ITS ANALYSIS OF MODERN RATE STRUCTURES?

A. Yes. The Company stated that the three-part rate with demand charge, which is defined as "a three part rate with a customer, demand, and time varying energy charge," is the top candidate based on the criteria of being grounded in cost of service analysis and performing well in respect to the promotion of equity and efficiency. In fact, the Company stated that the three part rate with demand charge "is significantly better than any other rate." *Id.,* page 5, line 6 to page 6, line 16.

Q. DID MECG AGREE IN THAT CASE WITH THE COMPANY'S ASSESSMENT OF THE THREE PART RATE WITH DEMAND CHARGE?

A. Yes. The Company's three part rate with demand charge concept, particularly with the inclusion of time varying energy rates, can be easily implemented in a cost-based manner, is fundamentally sound, and leads to transparent, understandable, and actionable rates.

Q. IN THIS CASE DOES THE COMPANY DISCUSS TRANSITIONING TO NEW RATE STRUCTURES AS PART OF THE AMI DEPLOYMENT?

A. Yes, however the Company focuses on residential rates. *See* Direct Testimony of Steven M. Wills*,* page 3, line 11 to line 21. Interestingly, the Company's Ultimate Savers proposal, which incorporates a demand charge for residential customers, proposes to price that demand charge at $7.03/kW, which is 16 percent higher than the proposed LGS summer demand charge and 213 percent higher than the proposed LGS winter demand charge. *See* Direct Testimony of Ahmad Faruqui, Ph.D., page 7, line 8.

Q. IN RECOGNITION OF THE BENEFITS TO CUSTOMERS OF AMI, SHOULD THE COMMISSION REQUIRE A TRANSITION AWAY FROM HOURS-USE RATES AS PART OF THIS CASE?

A. Yes. The Commission should require Ameren to redesign LGS and SP as three part rates with unbundled demand charges and time varying energy charges and for all LGS and SP customers to be transitioned to those rates by 2025, which is my understanding of when the Company anticipates AMI will be fully deployed. However, it is important to make changes now to move LGS and SP rates closer to cost of service levels.

Q. WHAT IS MECG'S RECOMMENDATION TO THE COMMISSION AT THE COMPANY'S PROPOSED REVENUE REQUIREMENTS FOR THE LGS AND SP CLASSES?

A. For the purposes of this docket, at the Company's proposed revenue requirement for the LGS and SP classes, MECG recommends that the Commission:

1) Accept Ameren's proposed customer charges and on-peak and off-peak adjusters for both LGS and SP, and Ameren's proposed Rider B credits and reactive charge for SP;
2) Increase the summer and winter demand charges for LGS and SP by three times the percent class increases; and
3) Apply the remaining proposed increase on an equal percentage basis to the summer and winter energy charges.

Q. HAVE YOU CALCULATED ILLUSTRATIVE RATES FOR LGS PER MECG'S PROPOSAL?

A. Yes, as shown in Exhibit SWC-17.

Q. WHAT IS MECG'S RECOMMENDATION TO THE COMMISSION IF THE COMMISSION APPROVES A LOWER LGS AND SP CLASS REVENUE REQUIREMENT THAN THAT PROPOSED BY THE COMPANY?

A. If the Commission awards an increase for these classes that is lower than that proposed by the Company, then the Commission can then take larger steps to address the over-recovery of demand-related costs through energy charges and associated intra-class subsidies. Specifically, the Commission should set the demand charges per MECG's recommendation above and apply the approved reduction in the class revenue requirement by reducing all base rate energy charges on an equal percentage basis.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Steve W. Chriss

Walmart Inc.
Business Address: 2608 SE J Street, Bentonville, AR, 72716

EXPERIENCE
July 2007 – Present
Walmart Inc., Bentonville, AR
Director, Energy Services (October 2018 – Present)
Director, Energy and Strategy Analysis (October 2016 – October 2018)
Senior Manager, Energy Regulatory Analysis (June 2011 – October 2016)
Manager, State Rate Proceedings (July 2007 – June 2011)

June 2003 – July 2007
Public Utility Commission of Oregon, Salem, OR
Senior Utility Analyst (February 2006 – July 2007)
Economist (June 2003 – February 2006)

January 2003 - May 2003
North Harris College, Houston, TX
Adjunct Instructor, Microeconomics

June 2001 - March 2003
Econ One Research, Inc., Houston, TX
Senior Analyst (October 2002 – March 2003)
Analyst (June 2001 – October 2002)

EDUCATION

2001	**Louisiana State University**	M.S., Agricultural Economics
1997-1998	**University of Florida**	Graduate Coursework, Agricultural Education and Communication
1997	**Texas A&M University**	B.S., Agricultural Development B.S., Horticulture

PRESENT MEMBERSHIPS
Arizona Independent Scheduling Administrators Association, Board
Arizonans for Electric Choice & Competition, Chairman
Arkansas Advanced Energy Foundation, Board
Edison Electric Institute National Key Accounts Program, Customer Advisory Group
Florida Advisory Council for Climate and Energy
Renewable Energy Buyers Alliance, Advisory Board

PAST MEMBERSHIPS
Southwest Power Pool, Corporate Governance Committee, 2019

TESTIMONY BEFORE REGULATORY COMMISSIONS
2021
Florida Docket No. 20210015-EI: In re: Petition for Rate Increase by Florida Power & Light Company.

California Docket No. R-20-08-020: Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering.

New Mexico Case No. 20-00238-UT: In the Matter of Southwestern Public Service Company's Application For: (1) Revision of its Retail Rates Under Advice Notice No. 292; (2) Authorization and Approval to Abandon its Plant X Unit 3 Generating Station; and (3) Other Associated Relief.

North Dakota Case No. PU-20-441: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota.

New Mexico Case No. 20-00222-UT: In the Matter of the Joint Application of Avangrid, Inc., Avangrid Networks, Inc., NM Green Holdings, Inc., Public Service Company of New Mexico and PNM Resources, Inc. For Approval of the Merger of NM Green Holdings, Inc. with PNM Resources, Inc.; Approval of a General Diversification Plan; and All Other Authorizations and Approvals Requires to Consummate and Implement this Transaction.

2020
Arizona Docket No. E-01345A-19-0236: In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of Ratemaking Purposes, to Fix a Just and Reasonable Return Thereon and to Approve Rate Schedules Designed to Develop Such Return.

Florida Docket No. 20200176-EI: In re: Petition by Duke Energy Florida, LLC for a Limited Proceeding to Approve Clean Energy Connection Program and Tariff and Stipulation.

Florida Docket No. 20200092-EI: In re: Storm Protection Plan Cost Recovery Clause.

Nevada Docket No. 20-05003: Application of Nevada Power Company d/b/a NV Energy Filed Under Advice Letter No. 504 to Establish Customer Price Stability Tariff Schedule No. CPST (the "Program") to Assist Certain Qualifying Customers During the COVID-19 Pandemic and Economic Downturn, and to Address Certain Customer Requests for Price Stability and Potential Cost Savings in Meeting Customer Specific Business Needs and Sustainability Objectives.

Nevada Docket No. 20-05004: Application of Sierra Pacific Power Company d/b/a NV Energy Filed Under Advice Letter No. 629-E to Establish Customer Price Stability Tariff Schedule No. CPST (the "Program") to Assist Certain Qualifying Customers During the COVID-19 Pandemic and Economic Downturn, and to Address Certain Customer Requests for Price Stability and Potential Cost Savings in Meeting Customer Specific Business Needs and Sustainability Objectives.

Utah Docket No. 20-035-04: Application of Rocky Mountain Power for the Authority to Increase its Retail Electric Utility Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Wyoming Docket No. 20000-578-ER-20: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates by Approximately $7.1 Million Per Year or 1.1 Percent, to Revise the Energy Cost Adjustment Mechanism, and to Discontinue Operations at Cholla Unit 4.

Virginia Case No. PUR-2020-00015: Application of Appalachian Power Company for a 2020 Triennial Review of the Rates, Terms and Conditions for the Provision of Generation, Distribution and Transmission Services Pursuant to §56-585.1 A of the Code of Virginia.

Oregon Docket No. UE 374: In the Matter of PacifiCorp d/b/a Pacific Power Request for a General Rate Revision.

Florida Docket No. 20200067-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Tampa Electric Company.

Florida Docket No. 20200069-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.

Florida Docket No. 20200070-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Gulf Power Company.

Florida Docket No. 20200071-EI: In re: Review of 2020-2029 Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Florida Power & Light Company.

North Carolina Docket No. E-2, Sub 1219: Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.
Missouri Case No. ER-2019-0374: In the Matter of the Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area.

North Carolina Docket No. E-7, Sub 1214: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Texas Docket No. 49831: Application of Southwestern Public Service Company for Authority to Change Rates.

2019
Missouri Case No. ER-2019-0335: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease its Revenues for Electric Service.

Michigan Case No. U-20561: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

Indiana Cause No. 45253: Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code §§ 8-1-2-42.7 and 8-1-2-61, For (1) Authority to Modify its Rates and Charges for Electric Utility Service Through a Step-In of New Rates and Charges Using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code § 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customer Classes.

Arizona Docket No. E-01933A-19-0228: In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Tucson Electric Power Company Devoted to its Operations Throughout the State of Arizona and for Related Approvals.

Georgia Docket No. 42516: In Re: Georgia Power's 2019 Rate Case.

Colorado Proceeding No. 19AL-0268E: Re: In the Matter of Advice No. 1797-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8-Electric Tariff to Implement Rate Changes Effective on Thirty Days' Notice.

New York Case No. 19-E-0378: Proceeding on the Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Case No. 19-E-0380: Proceeding on the Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

Maryland Case No. 9610: In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates.

Nevada Docket No. 19-06002: In the Matter of the Application by Sierra Pacific Power Company, D/B/A NV Energy, Filed Pursuant to NRS 704.110(3) and NRS 704.110(4), Addressing its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers.

Florida Docket No. 20190061-EI: In Re: Petition of Florida Power & Light Company for Approval of FPL SolarTogether Program and Tariff.

Wisconsin Docket No. 6690-UR-126: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates – Test Year 2020.

Wisconsin Docket No. 5-UR-109: Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates – Test Year 2020.

New Mexico Case No. 19-00158-UT: In the Matter of the Application of Public Service Company of New Mexico for Approval of PNM Solar Direct Voluntary Renewable Energy Program, Power Purchase Agreement, and Advice Notice Nos. 560 and 561.

Indiana Cause No. 45235: Petition of Indiana Michigan Power Company, and Indiana Corporation, for Authority to Increase its Rates and Charges for Electric Utility Service through a Phase In Rate Adjustment; and for Approval of Related Relief Including: (1) Revised Depreciation Rates; (2) Accounting Relief; (3) Inclusion in Rate Base of Qualified Pollution Control Property and Clean Energy Project; (4) Enhancements to the Dry Sorbent Injection System; (5) Advanced Metering Infrastructure; (6) Rate Adjustment Mechanism Proposals; and (7) New Schedules of Rates, Rules and Regulations.

Iowa Docket No. RPU-2019-0001: In Re: Interstate Power and Light Company.

Texas Docket No. 49494: Application of AEP Texas Inc. for Authority to Change Rates.

Arkansas Docket No. 19-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Virginia Case No. PUR-2019-00050: Application of Virginia Electric and Power Company for Determination of the Fair Rate of Return on Common Equity Pursuant to § 56-585.1:1 of the Code of Virginia.

Indiana Docket No. 45159: Petition of Northern Indiana Public Service Company LLC Pursuant to Indiana Code §§ 8-1-2-42.7, 8-1-2-61 and Indiana Code §§ 1-2.5-6 for (1) Authority to Modify its Rates and Charges for Electric Utility Service Through a Phase In of Rates; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief; and (5) Approval of a New Service Structure for Industrial Rates.

Texas Docket No. 49421: Application of Centerpoint Energy Houston Electric, LLC for Authority to Change Rates.

Nevada Docket No. 18-11015: Re: Application of Nevada Power Company d/b/a NV Energy, Filed Under Advice No. 491, to Implement NV Greenenergy 2.0 Rider Schedule No. NGR 2.0 to Allow Eligible

Commercial Bundled Service Customers to Voluntarily Contract with the Utility to Increase Their Use of Reliance on Renewable Energy at Current Market-Based Fixed Prices.

Nevada Docket No. 18-11016: Re: Application of Sierra Pacific Power Company d/b/a NV Energy, Filed Under Advice No. 614-E, to Implement NV Greenenergy 2.0 Rider Schedule No. NGR 2.0 to Allow Eligible Commercial Bundled Service Customers to Voluntarily Contract with the Utility to Increase Their Use of Reliance on Renewable Energy at Current Market-Based Fixed Prices.

Georgia Docket No. 42310: In Re: Georgia Power Company's 2019 Integrated Resource Plan and Application for Certification of Capacity From Plant Scherer Unit 3 and Plant Goat Rock Units 9-12 and Application for Decertification of Plant Hammond Units 1-4, Plant Mcintosh Unit 1, Plant Langdale Units 5-6, Plant Riverview Units 1-2, and Plant Estatoah Unit 1.

Wyoming Docket Nos. 20003-177-ET-18: In the Matter of the Application of Cheyenne Light, Fuel and Power Company D/B/A Black Hills Energy For Approval to Implement a Renewable Ready Service Tariff.

South Carolina Docket No. 2018-318-E: In the Matter of the Application of Duke Energy Progress, LLC For Adjustments in Electric Rate Schedules and Tariffs.

Montana Docket No. D2018.2.12: Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design.

Louisiana Docket No. U-35019: In Re: Application of Entergy Louisiana, LLC for Authorization to Make Available Experimental Renewable Option and Rate Schedule ERO.

Arkansas Docket No. 18-037-TF: In the Matter of the Petition of Entergy Arkansas, Inc. For Its Solar Energy Purchase Option.

2018

South Carolina Docket No. 2017-370-E: Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Inc., for Review and Approval of a Proposed Business Combination Between SCANA Corporation and Dominion Energy, Inc., as may be Required, and for a Prudency Determination Regarding the Abandonment of the V.C. Summer Units 2 & 3 Project and Associated Customer Benefits and Cost Recovery Plans.

Kansas Docket No. 18-KCPE-480-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Virginia Case No. PUR-2017-00173: Petition of Wal-Mart Stores East, LP and Sam's East, Inc. for Permission to Aggregate or Combine Demands of Two or More Individual Nonresidential Retail Customers of Electric Energy Pursuant to § 56-577 A 4 of the Code of Virginia.

Virginia Case No. PUR-2017-00174: Petition of Wal-Mart Stores East, LP and Sam's East, Inc. for Permission to Aggregate or Combine Demands of Two or More Individual Nonresidential Retail Customers of Electric Energy Pursuant to § 56-577 A 4 of the Code of Virginia.

Oregon Docket No. UM 1953: In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff.

Virginia Case No. PUR-2017-00179: Application of Appalachian Power Company for Approval of an 100% Renewable Energy Rider Pursuant to § 56-577.A.5 of the Code of Virginia.

Missouri Docket No. ER-2018-0145: In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service.

Missouri Docket No. ER-2018-0146: In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service.

Kansas Docket No. 18-WSEE-328-RTS: In the Matter of the Joint Application of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Oregon Docket No. UE 335: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

North Dakota Case No. PU-17-398: In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota.

Virginia Case No. PUR-2017-00179: Application of Appalachian Power Company for Approval of an 100 Percent Renewable Energy Rider Pursuant to § 56-577 A 5 of the Code of Virginia.

Missouri Case No. ET-2018-0063: In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff.

New Mexico Case No. 17-00255-UT: In the Matter of Southwestern Public Service Company's Application for Revision of its Retail Rates Under Advice Notice No. 272.

Virginia Case No. PUR-2017-00157: Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs for Residential and Non-Residential Customers.

Kansas Docket No. 18-KCPE-095-MER: In the Matter of the Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar Energy, Inc. and Great Plains Energy Incorporated.

North Carolina Docket No. E-7, Sub 1146: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Louisiana Docket No. U-34619: In Re: Application for Expedited Certification and Approval of the Acquisition of Certain Renewable Resources and the Construction of a Generation Tie Pursuant to the 1983 and/or/1994 General Orders.

Missouri Case No. EM-2018-0012: In the Matter of the Application of Great Plains Energy Incorporated for Approval of its Merger with Westar Energy, Inc.

2017
Arkansas Docket No. 17-038-U: In the Matter of the Application of Southwestern Electric Power Company for Approval to Acquire a Wind Generating Facility and to Construct a Dedicated Generation Tie Line.

Texas Docket No. 47461: Application of Southwestern Electric Power Company for Certificate of Convenience and Necessity Authorization and Related Relief for the Wind Catcher Energy Connection Project.

Oklahoma Cause No. PUD 201700267: Application of Public Service Company of Oklahoma for Approval of the Cost Recovery of the Wind Catcher Energy Connection Project; A Determination There is Need for the Project; Approval for Future Inclusion in Base Rates Cost Recovery of Prudent Costs Incurred by PSO for the Project; Approval of a Temporary Cost Recovery Rider; Approval of Certain Accounting Procedures Regarding Federal Production Tax Credits; Waiver of OAC 165:35-38-5(E); And Such Other Relief the Commission Deems PSO is Entitled.

Nevada Docket No. 17-06003: In the Matter of the Application of Nevada Power Company, d/b/a NV Energy, Filed Pursuant to NRS 704.110(3) and (4), Addressing Its Annual Revenue Requirement for General Rates Charged to All Classes of Customers.

North Carolina Docket No. E-2, Sub 1142: In the Matter of the Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Oklahoma Cause No. PUD 201700151: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Kentucky Case No. 2017-00179: Electronic Application of Kentucky Power Company for (1) a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2017 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; (4) an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) an Order Granting All Other Requested Relief.

New York Case No. 17-E-0238: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Niagara Mohawk Power Corporation for Electric and Gas Service.

Virginia Case No. PUR-2017-00060: Application of Virginia Electric and Power Company for Approval of 100 Percent Renewable Energy Tariffs Pursuant to §§ 56-577 A 5 and 56-234 of the Code of Virginia.

New Jersey Docket No. ER17030308: In the Matter of the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, for Approval of a Grid Resiliency Initiative and Cost Recovery Related Thereto, and for Other Appropriate Relief.

Texas Docket No. 46831: Application of El Paso Electric Company to Change Rates.

Oregon Docket No. UE 319: In the Matter of Portland General Electric Company, Request for a General Rate Revision.

New Mexico Case No. 16-00276-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice No. 533.

Minnesota Docket No. E015/GR-16-664: In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota.

Ohio Case No. 16-1852-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, In the Form of an Electric Security Plan.

Texas Docket No. 46449: Application of Southwestern Electric Power Company for Authority to Change Rates.

Arkansas Docket No. 16-052-U: In the Matter of the Application of Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges, and Tariffs.

Missouri Case No. EA-2016-0358: In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood-Montgomery 345 kV Transmission Line.

Florida Docket No. 160186-Ei: In Re: Petition for Increase in Rates by Gulf Power Company.

2016

Missouri Case No. ER-2016-0179: In the Matter of Union Electric Company d/b/a Ameren Missouri Tariffs to Increase its Revenues for Electric Service.

Kansas Docket No. 16-KCPE-593-ACQ: In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar Energy, Inc. by Great Plains Energy Incorporated.

Missouri Case No. EA-2016-0208: In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Offer a Pilot Distributed Solar Program and File Associated Tariff.

Utah Docket No. 16-035-T09: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 34, Renewable Energy Tariff.

Pennsylvania Public Utility Commission Docket No. R-2016-2537359: Pennsylvania Public Utility Commission v. West Penn Power Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537352: Pennsylvania Public Utility Commission v. Pennsylvania Electric Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537355: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2016-2537349: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Michigan Case No. U-17990: In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Florida Docket No. 160021-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

Minnesota Docket No. E-002/GR-15-816: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota.

Colorado Public Utilities Commission Docket No. 16AL-0048E: Re: In the Matter of Advice Letter No. 1712-Electric Filed by Public Service Company of Colorado to Replace Colorado PUC No.7-Electric Tariff with Colorado PUC No. 8-Electric Tariff.

Colorado Public Utilities Commission Docket No. 16A-0055E: Re: In the Matter of the Application of Public Service Company of Colorado for Approval of its Solar*Connect Program.

Missouri Public Service Commission Case No. ER-2016-0023: In the Matter of the Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company.

Georgia Public Service Commission Docket No. 40161: In Re: Georgia Power Company's 2016 Integrated Resource Plan and Application for Decertification of Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1 CT, and Intercession City CT.

Oklahoma Corporation Commission Cause No. PUD 201500273: In the Matter of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

New Mexico Case No. 15-00261-UT: In the Matter of the Application of Public Service Company of New Mexico for Revision of its Retail Electric Rates Pursuant to Advice Notice No. 513.

2015
Indiana Utility Regulatory Commission Cause No. 44688: Petition of Northern Indiana Public Service Company for Authority to Modify its Rates and Charges for Electric Utility Service and for Approval of: (1) Changes to its Electric Service Tariff Including a New Schedule of Rates and Charges and Changes to the General Rules and Regulations and Certain Riders; (2) Revised Depreciation Accrual Rates; (3) Inclusion in its Basic Rates and Charges of the Costs Associated with Certain Previously Approved Qualified Pollution Control Property, Clean Coal Technology, Clean Energy Projects and Federally Mandated Compliance Projects; and (4) Accounting Relief to Allow NIPSCO to Defer, as a Regulatory Asset or Liability, Certain Costs for Recovery in a Future Proceeding.

Public Utility Commission of Texas Docket No. 44941: Application of El Paso Electric Company to Change Rates.

Arizona Corporation Commission Docket No. E-04204A-15-0142: In the matter of the Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realized a Reasonable Rate of Return on the Fair Value of the Properties of UNS Electric, Inc. Devoted to its Operations Throughout the State of Arizona, and for Related Approvals.

Rhode Island Public Utilities Commission Docket No. 4568: In Re: National Grid's Rate Design Plan.

Oklahoma Corporation Commission Cause No. PUD 201500208: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations and Conditions of Service for Electric Service in the State of Oklahoma.

Public Service Commission of Wisconsin Docket No. 4220-UR-121: Application of Northern States Power Company, A Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Public Service Commission Docket No. 15-015-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

New York Public Service Commission Case No. 15-E-0283: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Electric Service.

New York Public Service Commission Case No. 15-G-0284: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of New York State Electric & Gas Corporation for Gas Service.

New York Public Service Commission Case No. 15-E-0285: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Electric Service.

New York Public Service Commission Case No. 15-G-0286: Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Rochester Gas & Electric Corporation for Gas Service.

Public Utilities Commission of Ohio Case No. 14-1693-EL-RDR: In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter Into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.

Public Service Commission of Wisconsin Docket No. 6690-UR-124: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Arkansas Public Service Commission Docket No. 15-034-U: In the Matter of an Interim Rate Schedule of Oklahoma Gas and Electric Company Imposing a Surcharge to Recover All Investments and Expenses Incurred Through Compliance with Legislative or Administrative Rules, Regulations, or Requirements Relating to the Public Health, Safety or the Environment Under the Federal Clean Air Act for Certain of its Existing Generation Facilities.

Kansas Corporation Commission Docket No. 15-WSEE-115-RTS: In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in their Charges for Electric Service.

Michigan Public Service Commission Case No. U-17767: In the Matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

Public Utility Commission of Texas Docket No. 43695: Application of Southwestern Public Service Company for Authority to Change Rates.

Kansas Corporation Commission Docket No. 15-KCPE-116-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Michigan Case No. U-17735: In the Matter of the Application of the Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Relief.

Kentucky Public Service Commission Case No. 2014-00396: Application of Kentucky Power Company for a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2014 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; and (4) an Order Granting All Other Required Approvals and Relief.

Kentucky Public Service Commission Case No. 2014-00371: In the Matter of the Application of Kentucky Utilities Company for an Adjustment of its Electric Rates.

Kentucky Public Service Commission Case No. 2014-00372: In the Matter of the Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates.

2014
Ohio Public Utilities Commission Case No. 14-1297-EL-SSO: In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan.

West Virginia Case No. 14-1152-E-42T: Appalachian Power Company and Wheeling Power Company, Both d/b/a American Electric Power, Joint Application for Rate Increases and Changes in Tariff Provisions.

Oklahoma Corporation Commission Cause No. PUD 201400229: In the Matter of the Application of Oklahoma Gas and Electric Company for Commission Authorization of a Plan to Comply with the Federal Clean Air Act and Cost Recovery; and for Approval of the Mustang Modernization Plan.

Missouri Public Service Commission Case No. ER-2014-0258: In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase its Revenues for Electric Service.
Pennsylvania Public Utility Commission Docket No. R-2014-2428742: Pennsylvania Public Utility Commission v. West Penn Power Company.

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

Pennsylvania Public Utility Commission Docket No. R-2014-2428744: Pennsylvania Public Utility Commission v. Pennsylvania Power Company.

Pennsylvania Public Utility Commission Docket No. R-2014-2428745: Pennsylvania Public Utility Commission v. Metropolitan Edison Company.

Washington Utilities and Transportation Commission Docket No. UE-141368: In the Matter of the Petition of Puget Sound Energy to Update Methodologies Used to Allocate Electric Cost of Service and For Electric Rate Design Purposes.

Washington Utilities and Transportation Commission Docket No. UE-140762: 2014 Pacific Power & Light Company General Rate Case.

West Virginia Public Service Commission Case No. 14-0702-E-42T: Monongahela Power Company and the Potomac Edison Company Rule 42T Tariff Filing to Increase Rates and Charges.

Ohio Public Utilities Commission Case No. 14-841-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of Case No. 14-841-EL-SSO an Electric Security Plan, Accounting Modifications and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 14AL-0660E: Re: In the Matter of the Advice Letter No. 1672-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Rate Changes Effective July 18, 2014.

Maryland Case No. 9355: In the Matter of the Application of Baltimore Gas and Electric Company for Authority to Increase Existing Rates and Charges for Electric and Gas Service.

Mississippi Public Service Commission Docket No. 2014-UN-132: In Re: Notice of Intent of Entergy Mississippi, Inc. to Modernize Rates to Support Economic Development, Power Procurement, and Continued Investment.

Nevada Public Utilities Commission Docket No. 14-05004: Application of Nevada Power Company d/b/a NV Energy for Authority to Increase its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto.

Utah Public Service Commission Docket No. 14-035-T02: In the Matter of Rocky Mountain Power's Proposed Electric Service Schedule No. 32, Service From Renewable Energy Facilities.

Florida Public Service Commission Docket No. 140002-EG: In Re: Energy Conservation Cost Recovery Clause.

Public Service Commission of Wisconsin Docket No. 6690-UR-123: Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates.

Connecticut Docket No. 14-05-06: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Virginia Corporation Commission Case No. PUE-2014-00026: Application of Appalachian Power Company for a 2014 Biennial Review for the Provision of Generation, Distribution and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Virginia Corporation Commission Case No. PUE-2014-00033: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to Va. Code § 56-249.6.

Arizona Corporation Commission Docket No. E-01345A-11-0224 (Four Corners Phase): In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Minnesota Public Utilities Commission Docket No. E-002/GR-13-868: In the Matter of the Application of Northern States Power Company, for Authority to Increase Rates for Electric Service in Minnesota.

Utah Public Service Commission Docket No. 13-035-184: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Missouri Public Service Commission Case No. EC-2014-0224: In the Matter of Noranda Aluminum, Inc.'s Request for Revisions to Union Electric Company d/b/a Ameren Missouri's Large Transmission Service Tariff to Decrease its Rate for Electric Service.

Oklahoma Corporation Commission Cause No. PUD 201300217: Application of Public Service Company of Oklahoma to be in Compliance with Order No. 591185 Issued in Cause No. PUD 201100106 Which Requires a Base Rate Case to be Filed by PSO and the Resulting Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Public Utilities Commission of Ohio Case No. 13-2386-EL-SSO: In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan.

2013
Oklahoma Corporation Commission Cause No. PUD 201300201: Application of Public Service Company of Oklahoma for Commission Authorization of a Standby and Supplemental Service Rate Schedule.

Georgia Public Service Commission Docket No. 36989: Georgia Power's 2013 Rate Case.

Florida Public Service Commission Docket No. 130140-EI: Petition for Rate Increase by Gulf Power Company.

Public Utility Commission of Oregon Docket No. UE 267: In the Matter of PACIFICORP, dba PACIFIC POWER, Transition Adjustment, Five-Year Cost of Service Opt-Out.

Illinois Commerce Commission Docket No. 13-0387: Commonwealth Edison Company Tariff Filing to Present the Illinois Commerce Commission with an Opportunity to Consider Revenue Neutral Tariff Changes Related to Rate Design Authorized by Subsection 16-108.5 of the Public Utilities Act.

Iowa Utilities Board Docket No. RPU-2013-0004: In Re: MidAmerican Energy Company.

South Dakota Public Utilities Commission Docket No. EL12-061: In the Matter of the Application of Black Hills Power, Inc. for Authority to Increase its Electric Rates. (filed with confidential stipulation)

Kansas Corporation Commission Docket No. 13-WSEE-629-RTS: In the Matter of the Applications of Westar Energy, Inc. and Kansas Gas and Electric Company for Approval to Make Certain Changes in their Charges for Electric Service.

Public Utility Commission of Oregon Docket No. UE 263: In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.

Arkansas Public Service Commission Docket No. 13-028-U: In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.

Virginia State Corporation Commission Docket No. PUE-2013-00020: Application of Virginia Electric and Power Company for a 2013 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Florida Public Service Commission Docket No. 130040-EI: Petition for Rate Increase by Tampa Electric Company.

South Carolina Public Service Commission Docket No. 2013-59-E: Application of Duke Energy Carolinas, LLC, for Authority to Adjust and Increase Its Electric Rates and Charges.

Public Utility Commission of Oregon Docket No. UE 262: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

New Jersey Board of Public Utilities Docket No. ER12111052: In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith; and for Approval of an Accelerated Reliability Enhancement Program ("2012 Base Rate Filing")

North Carolina Utilities Commission Docket No. E-7, Sub 1026: In the Matter of the Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Public Utility Commission of Oregon Docket No. UE 264: PACIFICORP, dba PACIFIC POWER, 2014 Transition Adjustment Mechanism.

Public Utilities Commission of California Docket No. 12-12-002: Application of Pacific Gas and Electric Company for 2013 Rate Design Window Proceeding.

Public Utilities Commission of Ohio Docket Nos. 12-426-EL-SSO, 12-427-EL-ATA, 12-428-EL-AAM, 12-429-EL-WVR, and 12-672-EL-RDR: In the Matter of the Application of the Dayton Power and Light Company Approval of its Market Offer.

Minnesota Public Utilities Commission Docket No. E-002/GR-12-961: In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota.

North Carolina Utilities Commission Docket E-2, Sub 1023: In the Matter of Application of Progress Energy Carolinas, Inc. For Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

2012

Public Utility Commission of Texas Docket No. 40443: Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2012-218-E: Application of South Carolina Electric & Gas Company for Increases and Adjustments in Electric Rate Schedules and Tariffs and Request for Mid-Period Reduction in Base Rates for Fuel.

Kansas Corporation Commission Docket No. 12-KCPE-764-RTS: In the Matter of the Application of Kansas City Power & Light Company to Make Certain Changes in its Charges for Electric Service.

Kansas Corporation Commission Docket No. 12-GIMX-337-GIV: In the Matter of a General Investigation of Energy-Efficiency Policies for Utility Sponsored Energy Efficiency Programs.

Florida Public Service Commission Docket No. 120015-EI: In Re: Petition for Rate Increase by Florida Power & Light Company.

California Public Utilities Commission Docket No. A.11-10-002: Application of San Diego Gas & Electric Company (U 902 E) for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design.

Utah Public Service Commission Docket No. 11-035-200: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Virginia State Corporation Commission Case No. PUE-2012-00051: Application of Appalachian Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

New Jersey Board of Public Utilities Docket No. ER11080469: In the Matter of the Petition of Atlantic City Electric for Approval of Amendments to Its Tariff to Provide for an Increase in Rates and Charges for Electric Service Pursuant to N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1 and For Other Appropriate Relief.

Public Utility Commission of Texas Docket No. 39896: Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs.

Missouri Public Service Commission Case No. EO-2012-0009:In the Matter of KCP&L Greater Missouri Operations Notice of Intent to File an Application for Authority to Establish a Demand-Side Programs Investment Mechanism.

Colorado Public Utilities Commission Docket No. 11AL-947E: In the Matter of Advice Letter No. 1597-Electric Filed by Public Service Company of Colorado to Revise its Colorado PUC No. 7-Electric Tariff to Implement a General Rate Schedule Adjustment and Other Changes Effective December 23, 2011.

Illinois Commerce Commission Docket No. 11-0721: Commonwealth Edison Company Tariffs and Charges Submitted Pursuant to Section 16-108.5 of the Public Utilities Act.

Public Utility Commission of Texas Docket No. 38951: Application of Entergy Texas, Inc. for Approval of Competitive Generation Service tariff (Issues Severed from Docket No. 37744).

California Public Utilities Commission Docket No. A.11-06-007: Southern California Edison's General Rate Case, Phase 2.

2011
Arizona Corporation Commission Docket No. E-01345A-11-0224: In the Matter of Arizona Public Service Company for a Hearing to Determine the Fair Value of Utility Property of the Company for Ratemaking Purposes, to Fix and Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return.

Oklahoma Corporation Commission Cause No. PUD 201100087: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

South Carolina Public Service Commission Docket No. 2011-271-E: Application of Duke Energy Carolinas, LLC for Authority to Adjust and Increase its Electric Rates and Charges.

Pennsylvania Public Utility Commission Docket No. P-2011-2256365: Petition of PPL Electric Utilities Corporation for Approval to Implement Reconciliation Rider for Default Supply Service.

North Carolina Utilities Commission Docket No. E-7, Sub 989: In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina.

Florida Public Service Commission Docket No. 110138: In Re: Petition for Increase in Rates by Gulf Power Company.

Public Utilities Commission of Nevada Docket No. 11-06006: In the Matter of the Application of Nevada Power Company, filed pursuant to NRS 704.110(3) for authority to increase its annual revenue requirement for general rates charged to all classes of customers to recover the costs of constructing the Harry Allen Combined Cycle plant and other generating, transmission, and distribution plant additions, to reflect changes in the cost of capital, depreciation rates and cost of service, and for relief properly related thereto.

North Carolina Utilities Commission Docket Nos. E-2, Sub 998 and E-7, Sub 986: In the Matter of the Application of Duke Energy Corporation and Progress Energy, Inc., to Engage in a Business Combination Transaction and to Address Regulatory Conditions and Codes of Conduct.

Public Utilities Commission of Ohio Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, and 11-350-EL-AAM: In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form on an Electric Security Plan and In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority.

Virginia State Corporation Commission Case No. PUE-2011-00037: In the Matter of Appalachian Power Company for a 2011 Biennial Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Illinois Commerce Commission Docket No. 11-0279 and 11-0282 (cons.): Ameren Illinois Company Proposed General Increase in Electric Delivery Service and Ameren Illinois Company Proposed General Increase in Gas Delivery Service.

Virginia State Corporation Commission Case No. PUE-2011-00045: Application of Virginia Electric and Power Company to Revise its Fuel Factor Pursuant to § 56-249.6 of the Code of Virginia.

Utah Public Service Commission Docket No. 10-035-124: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.

Maryland Public Utilities Commission Case No. 9249: In the Matter of the Application of Delmarva Power & Light for an Increase in its Retail Rates for the Distribution of Electric Energy.

Minnesota Public Utilities Commission Docket No. E002/GR-10-971: In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota.

Michigan Public Service Commission Case No. U-16472: In the Matter of the Detroit Edison Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy, and for Miscellaneous Accounting Authority.

2010
Public Utilities Commission of Ohio Docket No. 10-2586-EL-SSO: In the Matter of the Application of Duke Energy Ohio for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications, and Tariffs for Generation Service.

Colorado Public Utilities Commission Docket No. 10A-554EG: In the Matter of the Application of Public Service Company of Colorado for Approval of a Number of Strategic Issues Relating to its DSM Plan, Including Long-Term Electric Energy Savings Goals, and Incentives.

Public Service Commission of West Virginia Case No. 10-0699-E-42T: Appalachian Power Company and Wheeling Power Company Rule 42T Application to Increase Electric Rates.

Oklahoma Corporation Commission Cause No. PUD 201000050: Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and Terms and Conditions of Service for Electric Service in the State of Oklahoma.

Georgia Public Service Commission Docket No. 31958-U: In Re: Georgia Power Company's 2010 Rate Case.

Washington Utilities and Transportation Commission Docket No. UE-100749: 2010 Pacific Power & Light Company General Rate Case.

Colorado Public Utilities Commission Docket No. 10M-254E: In the Matter of Commission Consideration of Black Hills Energy's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Colorado Public Utilities Commission Docket No. 10M-245E: In the Matter of Commission Consideration of Public Service Company of Colorado Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act."

Public Service Commission of Utah Docket No. 09-035-15 *Phase II*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Utility Commission of Oregon Docket No. UE 217: In the Matter of PACIFICORP, dba PACIFIC POWER Request for a General Rate Revision.

Mississippi Public Service Commission Docket No. 2010-AD-57: In Re: Proposal of the Mississippi Public Service Commission to Possibly Amend Certain Rules of Practice and Procedure.

Indiana Utility Regulatory Commission Cause No. 43374: Verified Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission to Approve an Alternative Regulatory Plan Pursuant to Ind. Code § 8-1-2.5-1, *ET SEQ*., for the Offering of Energy Efficiency Conservation, Demand Response, and Demand-Side Management Programs and Associated Rate Treatment Including Incentives Pursuant to a Revised Standard Contract Rider No. 66 in Accordance with Ind. Code §§ 8-1-2.5-1 *ET SEQ*. and 8-1-2-42 (a); Authority to Defer Program Costs Associated with its Energy Efficiency Portfolio of Programs; Authority to Implement New and Enhanced Energy Efficiency Programs, Including the Powershare® Program in its Energy Efficiency Portfolio of Programs; and Approval of a Modification of the Fuel Adjustment Clause Earnings and Expense Tests.

Public Utility Commission of Texas Docket No. 37744: Application of Entergy Texas, Inc. for Authority to Change Rates and to Reconcile Fuel Costs.

South Carolina Public Service Commission Docket No. 2009-489-E: Application of South Carolina Electric & Gas Company for Adjustments and Increases in Electric Rate Schedules and Tariffs.

Kentucky Public Service Commission Case No. 2009-00459: In the Matter of General Adjustments in Electric Rates of Kentucky Power Company.

Virginia State Corporation Commission Case No. PUE-2009-00125: For acquisition of natural gas facilities Pursuant to § 56-265.4:5 B of the Virginia Code.

Arkansas Public Service Commission Docket No. 10-010-U: In the Matter of a Notice of Inquiry Into Energy Efficiency.

Connecticut Department of Public Utility Control Docket No. 09-12-05: Application of the Connecticut Light and Power Company to Amend its Rate Schedules.

Arkansas Public Service Commission Docket No. 09-084-U: In the Matter of the Application of Entergy Arkansas, Inc. For Approval of Changes in Rates for Retail Electric Service.

Missouri Public Service Commission Docket No. ER-2010-0036: In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.

Public Service Commission of Delaware Docket No. 09-414: In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Charges.

2009

Virginia State Corporation Commission Case No. PUE-2009-00030: In the Matter of Appalachian Power Company for a Statutory Review of the Rates, Terms, and Conditions for the Provision of Generation, Distribution, and Transmission Services Pursuant to § 56-585.1 A of the Code of Virginia.

Public Service Commission of Utah Docket No. 09-035-15 *Phase I*: In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism.

Public Service Commission of Utah Docket No. 09-035-23: In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.

Colorado Public Utilities Commission Docket No. 09AL-299E: Re: The Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1535 – Electric.

Arkansas Public Service Commission Docket No. 09-008-U: In the Matter of the Application of Southwestern Electric Power Company for Approval of a General Change in Rates and Tariffs.

Oklahoma Corporation Commission Docket No. PUD 200800398: In the Matter of the Application of Oklahoma Gas and Electric Company for an Order of the Commission Authorizing Applicant to Modify its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma.

Public Utilities Commission of Nevada Docket No. 08-12002: In the Matter of the Application by Nevada Power Company d/b/a NV Energy, filed pursuant to NRS §704.110(3) and NRS §704.110(4) for authority to increase its annual revenue requirement for general rates charged to all classes of customers, begin to recover the costs of acquiring the Bighorn Power Plant, constructing the Clark Peakers, Environmental Retrofits and other generating, transmission and distribution plant additions, to reflect changes in cost of service and for relief properly related thereto.

New Mexico Public Regulation Commission Case No. 08-00024-UT: In the Matter of a Rulemaking to Revise NMPRC Rule 17.7.2 NMAC to Implement the Efficient Use of Energy Act.

Indiana Utility Regulatory Commission Cause No. 43580: Investigation by the Indiana Utility Regulatory Commission, of Smart Grid Investments and Smart Grid Information Issues Contained in 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. § 2621(d)), as Amended by the Energy Independence and Security Act of 2007.

Louisiana Public Service Commission Docket No. U-30192 *Phase II (February 2009)*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

South Carolina Public Service Commission Docket No. 2008-251-E: In the Matter of Progress Energy Carolinas, Inc.'s Application For the Establishment of Procedures to Encourage Investment in Energy Efficient Technologies; Energy Conservation Programs; And Incentives and Cost Recovery for Such Programs.

2008
Colorado Public Utilities Commission Docket No. 08A-366EG: In the Matter of the Application of Public Service Company of Colorado for approval of its electric and natural gas demand-side management (DSM) plan for calendar years 2009 and 2010 and to change its electric and gas DSM cost adjustment rates effective January 1, 2009, and for related waivers and authorizations.

Public Service Commission of Utah Docket No. 07-035-93: In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge.

Indiana Utility Regulatory Commission Cause No. 43374: Petition of Duke Energy Indiana, Inc. Requesting the Indiana Utility Regulatory Commission Approve an Alternative Regulatory Plan for the Offering of Energy Efficiency, Conservation, Demand Response, and Demand-Side Management.

Public Utilities Commission of Nevada Docket No. 07-12001: In the Matter of the Application of Sierra Pacific Power Company for authority to increase its general rates charged to all classes of electric customers to reflect an increase in annual revenue requirement and for relief properly related thereto.

Louisiana Public Service Commission Docket No. U-30192 *Phase II*: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Colorado Public Utilities Commission Docket No. 07A-420E: In the Matter of the Application of Public Service Company of Colorado For Authority to Implement and Enhanced Demand Side Management Cost Adjustment Mechanism to Include Current Cost Recovery and Incentives.

2007
Louisiana Public Service Commission Docket No. U-30192: Ex Parte, Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery.

Public Utility Commission of Oregon Docket No. UG 173: In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Request to Open an Investigation into the Earnings of Cascade Natural Gas.

2006
Public Utility Commission of Oregon Docket No. UE 180/UE 181/UE 184: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.

Public Utility Commission of Oregon Docket No. UE 179: In the Matter of PACIFICORP, dba PACIFIC POWER AND LIGHT COMPANY Request for a general rate increase in the company's Oregon annual revenues.

Public Utility Commission of Oregon Docket No. UM 1129 *Phase II*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

2005
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I Compliance*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

Public Utility Commission of Oregon Docket No. UX 29: In the Matter of QWEST CORPORATION Petition to Exempt from Regulation Qwest's Switched Business Services.

2004
Public Utility Commission of Oregon Docket No. UM 1129 *Phase I*: Investigation Related to Electric Utility Purchases From Qualifying Facilities.

TESTIMONY BEFORE LEGISLATIVE BODIES
2020
Regarding Missouri Senate Joint Resolution 34: Written testimony submitted to the Missouri Senate Transportation, Infrastructure and Public Safety Committee, January 30, 2020.

2019
Regarding North Carolina Senate Bill 559: Written testimony submitted to the North Carolina Committee on Agriculture/Environment/Natural Resources, April 17, 2019.

Regarding Missouri Senate Joint Resolution 25: Written testimony submitted to the Missouri Senate Committee on Judiciary, March 28, 2019.

Regarding South Carolina House Bill 3659: Written testimony submitted to the South Carolina Senate Committee on Judiciary, March 14, 2019.

Regarding Kansas Senate Bill 69: Written testimony submitted to the Kansas Committee on Utilities, February 19, 2019.

2018
Regarding Missouri Senate Bill 564: Testimony before the Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment, January 10, 2018.

2017
Regarding Missouri Senate Bill 190: Testimony before the Missouri Senate Committee on Commerce, Consumer Protection, Energy and the Environment, January 25, 2017.

2016
Regarding Missouri House Bill 1726: Testimony before the Missouri House Energy and Environment Committee, April 26, 2016.

2014
Regarding Kansas House Bill 2460: Testimony Before the Kansas House Standing Committee on Utilities and Telecommunications, February 12, 2014.

2012
Regarding Missouri House Bill 1488: Testimony Before the Missouri House Committee on Utilities, February 7, 2012.

2011
Regarding Missouri Senate Bills 50, 321, 359, and 406: Testimony Before the Missouri Senate Veterans' Affairs, Emerging Issues, Pensions, and Urban Affairs Committee, March 9, 2011.

AFFIDAVITS
2015
Supreme Court of Illinois, Docket No. 118129, Commonwealth Edison Company et al., respondents, v. Illinois Commerce Commission et al. (Illinois Competitive Energy Association et al., petitioners). Leave to appeal, Appellate Court, First District.

2011
Colorado Public Utilities Commission Docket No. 11M-951E: In the Matter of the Petition of Public Service Company of Colorado Pursuant to C.R.S. § 40-6-111(1)(d) for Interim Rate Relief Effective on or before January 21, 2012.

ENERGY INDUSTRY PUBLICATIONS AND PRESENTATIONS
Panelist, US City & Corporate Clean Energy Procurement and its Role in Achieving the Paris Agreement's Goals, United States Environmental Protection Agency, September 1, 2021.

Panelist, WalStreet Fireside Chat – Future of Energy, Bentonville Chamber of Commerce, July 27, 2021.

Panelist, Corporate Customer Partnerships, EEI 2021: The Road to Net Zero, June 9, 2021.

Panelist, Counting to Clean: Corporate Sustainability and Renewable Energy, Energy Bar Association, May 12, 2021.

Speaker, Designing a Customer-Centric Clean Energy Standard, REBA Connect 2021 Virtual Member Summit, May 11, 2021.

Panelist, Delivering 100% Carbon Free Energy: Options & Issues, Northwestern Center on Law, Business, and Economics, March 16, 2021.

Electric Company Updates and Discussion on Best Practices for Serving National Corporate Customers Webinar, Edison Electric Institute, March 9, 2021.

Panelist, ComEd Fleet Electrification Webinar, December 10, 2020.

Panelist, Corporate Offtaker Perspectives Panel, Southeast Renewable Energy Summit, November 18, 2020.

Panelist, EEI National Key Accounts – Connections that Mean Business for Corporate Customers, EEI Fall National Key Accounts Workshop, October 28, 2020.

Panelist, COVID-19, a Catalyzer or a Barrier to Decarbonization?, Power & Renewables Summit 2020, September 28, 2020.

Panelist, What Organized Markets Can Do for You, REBA Connect: Virtual Member Summit 2020, June 2, 2020.

Panelist, Expanding Future Procurement Options, REBA Connect: Virtual Member Summit 2020, May 13, 2020.

Panelist, Renewable Energy Options for Large Utility Customers, NARUC Center for Partnership & Innovation Webinar Series, January 16, 2020.

Panelist, Pathways to Integrating Customer Clean Energy Demand in Utility Planning, REBA: Market Innovation webinar, January 13, 2020.

Panelist, Should Full Electrification of Energy Systems be Our Goal? If it's No Longer Business as Usual, What Does That Mean for Consumers?, National Association of State Utility Consumer Advocates 2019 Annual Meeting, San Antonio, Texas, November 18, 2019.

Panelist, Fleet Electrification, Federal Utility Partnership Working Group Seminar, Washington, DC, November 8, 2019.

Panelist, Tackling the Challenges of Extreme Weather, Edison Electric Institute Fall National Key Accounts Workshop, Las Vegas, Nevada, October 8, 2019.

Panelist, Fleet Electrification: Tackling the Challenges and Seizing the Opportunities for Electric Trucks, Powering the People 2019, Washington, D.C., September 24, 2019.

Panelist, From the Consumer Perspective, Mid-American Regulatory Conference 2019 Annual Meeting, Des Moines, Iowa, August 13, 2019.

Panelist, Redefining Resiliency: Emerging Technologies Benefiting Customers and the Grid, EPRI 2019 Summer Seminar, Chicago, Illinois, August 12, 2019.

Panelist, Energy Policies for Economic Growth, 2019 Energy Policy Summit, NCSL Legislative Summit, Nashville, Tennessee, August 5, 2019.

Panelist, Gateway to Energy Empowerment for Customers, Illumination Energy Summit, Columbus, Ohio, May 15, 2019.

Panelist, Advancing Clean Energy Solutions Through Stakeholder Collaborations, 2019 State Energy Conference of North Carolina, Raleigh, North Carolina, May 1, 2019.

Panelist, Fleet Electrification: Getting Ready for the Transition, Edison Electric Institute Spring National Key Accounts Workshop, Seattle, Washington, April 8, 2019.

Panelist, Where the Fleet Meets the Pavement, Which Way to Electrification of the U.S. Transportation System?, Washington, D.C., April 4, 2019.

Panelist, Improving Renewable Energy Offerings: What Have We Learned?, Advanced Energy Economy Webinar, March 26, 2019.

Speaker, National Governors Association Southeast Regional Transportation Electrification Workshop, Nashville, Tennessee, March 11, 2019.

Speaker, Walmart Spotlight: A Day in the Life of a National Energy Manager, Touchstone Energy Cooperatives Net Conference 2019, San Diego, California, February 12, 2019.

Panelist, National Accounts: The Struggle is Real, American Public Power Association Customer Connections Conference, Orlando, Florida, November 6, 2018.

Panelist, Getting in Front of Customers Getting Behind the Meter Solutions, American Public Power Association Customer Connections Conference, Orlando, Florida, November 6, 2018.

Panelist, Sustainable Fleets: The Road Ahead for Electrifying Fleet Operations, EEI National Key Accounts 2018 Fall Workshop, San Antonio, Texas, October 23, 2018.

Panelist, Meeting Corporate Clean Energy Requirements in Virginia, Renewable Energy Buyers Alliance Summit, Oakland, California, October 15, 2018.

Panelist, What Are the Anticipated Impacts on Pricing and Reliability in the Changing Markets?, Southwest Energy Conference, Phoenix, Arizona, September 21, 2018.

Speaker, Walmart's Project Gigaton – Driving Renewable Energy Sourcing in the Supply Chain, Smart Energy Decisions Webcast Series, July 11, 2018.

Panelist, Customizing Energy Solutions, Edison Electric Institute Annual Convention, San Diego, California, June 7, 2018.

Powering Ohio Report Release, Columbus, Ohio, May 29, 2018.

Panelist, The Past, Present, and Future of Renewable Energy: What Role Will PURPA, Mandates, and Collaboration Play as Renewables Become a Larger Part of Our Energy Mix?, 36th National Regulatory Conference, Williamsburg, Virginia, May 17, 2018.

Panelist, Sustainability Milestone Deep Dive Session, Walmart Global Sustainability Leaders Summit, Bentonville, Arkansas, April 18, 2018.

Panelist, The Customer's Voice, Tennessee Valley Authority Distribution Marketplace Forum, Murfreesboro, Tennessee, April 3, 2018.

Panelist, Getting to Yes with Large Customers to Meet Sustainability Goals, The Edison Foundation Institute for Electric Innovation Powering the People, March 7, 2018.

Panelist, The Corporate Quest for Renewables, 2018 NARUC Winter Policy Summit, Washington, D.C., February 13, 2018.

Panelist, Solar and Renewables, Touchstone Energy Cooperatives NET Conference 2018, St. Petersburg, Florida, February 6, 2018.

Panelist, Missouri Public Service Commission November 20, 2017 Workshop in File No. EW-2017-0245.

Panelist, Energy and Climate Change, 2017-18 Arkansas Law Review Symposium: Environmental Sustainability and Private Governance, Fayetteville, Arkansas, October 27, 2017.

Panelist, Customer – Electric Company – Regulator Panel, Edison Electric Institute Fall National Key Accounts Workshop, National Harbor, Maryland, October 12, 2017.

Panelist, What Do C&I Buyers Want, Solar Power International, Las Vegas, Nevada, September 12, 2017.

Panelist, Partnerships for a Sustainable Future, American Public Power Association National Conference, Orlando, Florida, June 20, 2017.

Panelist, Corporate Renewable Energy Buyers in the Southeast, SEARUC 2017, Greensboro, Georgia, June 12, 2017.

Panelist, Transitioning Away from Traditional Utilities, Utah Association of Energy Users Annual Conference, Salt Lake City, Utah, May 18, 2017.

Panelist, Regulatory Approaches for Integrating and Facilitating DERs, New Mexico State University Center for Public Utilities Advisory Council Current Issues 2017, Santa Fe, New Mexico, April 25, 2017.

Presenter, Advancing Renewables in the Midwest, Columbia, Missouri, April 24, 2017.

Panelist, Leveraging New Energy Technologies to Improve Service and Reliability, Edison Electric Institute Spring National Key Accounts Workshop, Phoenix, Arizona, April 11, 2017.

Panelist, Private Sector Demand for Renewable Power, Vanderbilt Law School, Nashville, Tennessee, April 4, 2017.

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Calculation of FERC Form 1 Reported LGS Revenue Per kWh Sold

Year	LGS Commercial		LGS Industrial		Total LGS			Cumulative Increase
	(MWH) (1)	($ Revenue) (2)	(MWH) (3)	($ Revenue) (4)	(MWH) (5) (1) + (3)	($ Revenue) (6) (2) + (4)	Revenue/kWh Sold (7) (6) / (5) / 1000	(%) (8)
2008	7,217,909	$ 404,821,983	1,091,791	$ 63,361,204	8,309,700	$ 468,183,187	$ 0.0563	
2009	7,080,575	$ 423,487,422	942,887	$ 59,330,101	8,023,462	$ 482,817,523	$ 0.0602	6.8%
2010	7,348,264	$ 479,441,021	981,778	$ 66,527,092	8,330,042	$ 545,968,113	$ 0.0655	16.3%
2011	7,273,526	$ 524,713,967	969,043	$ 72,008,088	8,242,569	$ 596,722,055	$ 0.0724	28.5%
2012	7,163,079	$ 523,948,387	941,992	$ 70,870,800	8,105,071	$ 594,819,187	$ 0.0734	30.3%
2013	7,153,501	$ 584,937,006	923,052	$ 77,741,042	8,076,553	$ 662,678,048	$ 0.0820	45.6%
2014	7,238,416	$ 586,009,104	925,273	$ 76,899,511	8,163,689	$ 662,908,615	$ 0.0812	44.1%
2015	7,181,050	$ 614,896,646	915,833	$ 80,126,654	8,096,883	$ 695,023,300	$ 0.0858	52.4%
2016	7,168,064	$ 588,880,866	894,348	$ 75,250,088	8,062,412	$ 664,130,954	$ 0.0824	46.2%
2017	7,017,603	$ 580,221,852	863,099	$ 72,888,052	7,880,702	$ 653,109,904	$ 0.0829	47.1%
2018	7,260,729	$ 613,262,354	864,726	$ 74,894,444	8,125,455	$ 688,156,798	$ 0.0847	50.3%
2019	6,969,113	$ 556,156,291	815,896	$ 67,057,265	7,785,009	$ 623,213,556	$ 0.0801	42.1%
2020	6,375,827	$ 490,759,257	765,610	$ 60,705,994	7,141,437	$ 551,465,251	$ 0.0772	37.1%

Sources:
2008 - 2020 / Q4 FERC Form 1, Union Electric Company, page 304.

Calculation of Proposed LGS and SP Increases in Excess of Cost of Service Levels

Customer Class	Current Retail Revenues	Proposed Base Revenue Requirement	Proposed Base Revenue Adjustment		Cost of Service Base Revenue Adjustment		Proposed Increase in Excess of Cost of Service
	($) (1)	($) (2)	($) (3) (2) - (1)	(%) (4) (3) / (1)	(%) (5)	($) (6) (5) X (1)	($) (7) (3) - (6)
Large General Service	$ 507,149,139	$ 567,788,047	$ 60,638,908	11.96%	1.4%	$ 7,100,088	$ 53,538,820
Small Primary Service	$ 220,416,108	$ 246,816,373	$ 26,400,265	11.98%	1.4%	$ 3,085,826	$ 23,314,439
Total	**$ 727,565,247**	**$ 814,604,420**	**$ 87,039,173**			**$ 10,185,913**	**$ 76,853,260**

Sources:
(1) - (4) Direct Testimony of Michael W. Harding, page 6, Table 3
(5) Direct Testimony of Michael W. Harding, page 5, Table 2

Calculation of Ameren's Proposed A&E 4NCP Production Plant Cost Allocator

			CP at the Generator (kW)											
			January	February	March	April	May	June	July	August	September	October	November	December
(1)		Residential	2,986,120	3,192,925	2,241,345	2,336,112	2,390,117	3,396,685	3,783,274	3,720,541	2,959,177	1,810,299	2,539,401	3,250,373
(2)		SGS	681,996	589,137	497,452	344,345	622,363	690,346	770,513	755,555	651,204	487,052	495,889	510,920
(3)		LGS	1,410,147	1,348,438	1,021,429	939,796	1,154,802	1,326,601	1,437,696	1,377,867	1,221,104	1,019,123	1,054,258	1,004,661
(4)		SP	523,077	528,403	469,084	473,737	551,379	540,752	587,996	585,266	556,477	489,167	479,898	400,980
(5)		LPS	423,281	425,726	432,374	433,057	502,047	519,075	512,915	530,932	513,243	474,383	419,422	368,339
(6)		Lighting	9,227	49	-	-	-	-	-	-	-	-	36,330	9,743
(7)		**Total**	**6,033,847**	**6,084,677**	**4,661,685**	**4,527,047**	**5,220,708**	**6,473,460**	**7,092,395**	**6,970,160**	**5,901,205**	**4,280,023**	**5,025,198**	**5,545,016**
(8)	(7) / max(7)	**Percent of Maximum**	**85%**	**86%**	**66%**	**64%**	**74%**	**91%**	**100%**	**98%**	**83%**	**60%**	**71%**	**78%**
(9)		**System Peak Load Rank**	**5**	**4**	**10**	**11**	**8**	**3**	**1**	**2**	**6**	**12**	**9**	**7**

Ameren Proposed A&E 4NCP

Step 1: Identify four highest NCP for each class, regardless of month

			Class NCP at the Generator (MW)											
			January	February	March	April	May	June	July	August	September	October	November	December
(10)		Residential	3,239	3,302	2,523	2,336	2,521	3,538	3,941	3,865	3,439	2,191	2,585	3,276
(11)		SGS	716	674	560	452	634	700	824	831	706	561	579	625
(12)		LGS/SP	1,933	1,877	1,628	1,515	1,776	1,971	2,095	2,106	1,911	1,641	1,701	1,699
(13)		LPS	438	435	461	453	511	533	534	538	515	486	450	440
(14)		Lighting	40	38	39	39	39	39	38	38	37	38	36	36
(15)	∑ (10)…(14)	**Total**	**6,366**	**6,326**	**5,211**	**4,794**	**5,481**	**6,781**	**7,433**	**7,378**	**6,608**	**4,917**	**5,352**	**6,076**

			Residential	SGS	LGS/SP	LPS	Lighting	System
		Step 2: Create four class peaks by ordering each selected customer class NCP by largest to smallest and average for each class						
(16)		Class Peak #1	3,941	831	2,106	538	40	7,456
(17)		Class Peak #2	3,865	824	2,095	534	39	7,358
(18)		Class Peak #3	3,538	716	1,971	533	39	6,798
(19)		Class Peak #4	3,439	706	1,933	515	39	6,632
(20)	Ave (16)…(19)	**Average of Class Peaks**	**3,696**	**769**	**2,026**	**530**	**39**	**7,061**
		Step 3: Adjust annual class MWH usage by losses						
(21)		Annual MWH	13,384,649	3,035,720	10,746,717	3,542,170	152,960	30,862,216
(22)		Losses	7.99%	7.99%	6.90%	4.15%	6.92%	7.16%
(23)	(21) X 1+(22)	MWH Adjusted for Losses	14,454,222	3,278,306	11,488,104	3,689,239	163,543	33,073,413
		Step 4: Calculate average demand for each class (MWH/8760) and class percentage of total system						
(24)	(23) / 8760	Average Demand (MW)	1,650	374	1,311	421	19	3,776
(25)	(24) / (24) System	Percent of System	43.70%	9.91%	34.74%	11.15%	0.49%	100.00%
		Step 5: Calculate excess demand for each class by subtracting average demand from average of class peaks and class percentage of total system (inc. Ameren lighting adjustment)						
(26)	(20) - (24)	Excess Demand (MW)	2,046	395	715	109	5	3,270
(27)	(26) / (26) System	Percent of System	62.57%	12.08%	21.86%	3.33%	0.16%	100.00%
		Step 6: Calculate system load factor (based on 1CP)						
(28)	(24) System	Average Demand (System)	3,776					
(29)	(7) July / 1000	System Peak Demand (July CP)	7,092					
(30)	(28) / (29)	System Load Factor	53.23%					
		Step 7: Multiply average demand percent of system for each class by system load factor to determine average demand contribution to allocator						
(31)	(25) X (30)	Average Demand Contribution to Allocator	23.26%	5.28%	18.49%	5.94%	0.26%	53.23%
		Step 8: Multiply excess demand percent of system for each class by 1 minus the system load factor to determine excess demand contribution to allocator						
(32)	(27) X 1 - (30)	Excess Demand Contribution to Allocator	29.26%	5.65%	10.22%	1.56%	0.07%	46.77%
		Step 9: Add average demand and excess demand contributions to calculate final allocation percentage for each class						
(33)	(31) + (32)	A&E 4NCP Allocator (Ameren)	52.53%	10.93%	28.71%	7.50%	0.34%	100.00%

Source:
CCOS Spreadsheet, A.F.1 -- 4NCP
Ameren Missouri Response to MECG 2.1

Calculation of 4NCP A&E Production Plant Cost Allocator per Section 393.1620.1(1) RSMo

			CP at the Generator (kW)											
			January	February	March	April	May	June	July	August	September	October	November	December
(1)		Residential	2,986,120	3,192,925	2,241,345	2,336,112	2,390,117	3,396,685	3,783,274	3,720,541	2,959,177	1,810,299	2,539,401	3,250,373
(2)		SGS	681,996	589,137	497,452	344,345	622,363	690,346	770,513	755,555	651,204	487,052	495,889	510,920
(3)		LGS	1,410,147	1,348,438	1,021,429	939,796	1,154,802	1,326,601	1,437,696	1,377,867	1,221,104	1,019,123	1,054,258	1,004,661
(4)		SP	523,077	528,403	469,084	473,737	551,379	540,752	587,996	585,266	556,477	489,167	479,898	400,980
(5)		LPS	423,281	425,726	432,374	433,057	502,047	519,075	512,915	530,932	513,243	474,383	419,422	368,339
(6)		Lighting	9,227	49	-	-	-	-	-	-	-	-	36,330	9,743
(7)		**Total**	**6,033,847**	**6,084,677**	**4,661,685**	**4,527,047**	**5,220,708**	**6,473,460**	**7,092,395**	**6,970,160**	**5,901,205**	**4,280,023**	**5,025,198**	**5,545,016**
(8)	(7) / max(7)	**Percent of Maximum**	**85%**	**86%**	**66%**	**64%**	**74%**	**91%**	**100%**	**98%**	**83%**	**60%**	**71%**	**78%**
(9)		**System Peak Load Rank**	**5**	**4**	**10**	**11**	**8**	**3**	**1**	**2**	**6**	**12**	**9**	**7**

A&E 4NCP per Language in MRS 393.1620(1)(1)

Step 1: Identify four highest NCP for each class for the four months with the highest system peak loads

			Class NCP at the Generator (MW)											
			January	February	March	April	May	June	July	August	September	October	November	December
(10)		Residential	3,239	3,302	2,523	2,336	2,521	3,538	3,941	3,865	3,439	2,191	2,585	3,276
(11)		SGS	716	674	560	452	634	700	824	831	706	561	579	625
(12)		LGS/SP	1,933	1,877	1,628	1,515	1,776	1,971	2,095	2,106	1,911	1,641	1,701	1,699
(13)		LPS	438	435	461	453	511	533	534	538	515	486	450	440
(14)		Lighting	40	38	39	39	39	39	38	38	37	38	36	36
(15)	∑ (10)...(14)	**Total**	**6,366**	**6,326**	**5,211**	**4,794**	**5,481**	**6,781**	**7,433**	**7,378**	**6,608**	**4,917**	**5,352**	**6,076**

Step 2: Create four class peaks by ordering each selected customer class NCP by largest to smallest and average for each class

			Residential	SGS	LGS/SP	LPS	Lighting	System
(16)		Class Peak #1	3,941	831	2,106	538	39	7,454
(17)		Class Peak #2	3,865	824	2,095	534	38	7,357
(18)		Class Peak #3	3,538	700	1,971	533	38	6,781
(19)		Class Peak #4	3,302	674	1,877	435	38	6,325
(20)	Ave (16)...(19)	**Average of Class Peaks**	**3,662**	**757**	**2,012**	**510**	**38**	**6,979**
		Step 3: Adjust annual class MWH usage by losses						
(21)		Annual MWH	13,384,649	3,035,720	10,746,717	3,542,170	152,960	30,862,216
(22)		Losses	7.99%	7.99%	6.90%	4.15%	6.92%	7.16%
(23)	(21) X 1+(22)	MWH Adjusted for Losses	14,454,222	3,278,306	11,488,104	3,689,239	163,543	33,073,413
		Step 4: Calculate average demand for each class (MWH/8760) and class percentage of total system						
(24)	(23) / 8760	Average Demand (MW)	1,650	374	1,311	421	19	3,776
(25)	(24) / (24) System	Percent of System	43.70%	9.91%	34.74%	11.15%	0.49%	100.00%
		Step 5: Calculate excess demand for each class by subtracting average demand from average of class peaks and class percentage of total system (inc. Ameren Lighting adjustment)						
(26)	(20) - (24)	Excess Demand (MW)	2,012	383	701	89	5	3,189
(27)	(26) / (26) System	Percent of System	63.08%	12.01%	21.97%	2.79%	0.15%	100.00%
		Step 6: Calculate system load factor (based on 1CP)						
(28)	(24) System	Average Demand (System)	3,776					
(29)	(7) July / 1000	System Peak Demand	7,092					
(30)	(28) / (29)	System Load Factor	53.23%					
		Step 7: Multiply average demand percent of system for each class by system load factor to determine average demand contribution to allocator						
(31)	(25) X (30)	Average Demand Contribution to Allocator	23.26%	5.28%	18.49%	5.94%	0.26%	53.23%
		Step 8: Multiply excess demand percent of system for each class by 1 minus the system load factor to determine excess demand contribution to allocator						
(32)	(27) X 1 - (30)	Excess Demand Contribution to Allocator	29.50%	5.62%	10.28%	1.30%	0.07%	46.77%
		Step 9: Add average demand and excess demand contributions to calculate final allocation percentage for each class						
(33)	(31) + (32)	A&E 4NCP Allocator (MRS 393.1620(1)(1))	52.76%	10.89%	28.77%	7.24%	0.33%	100.00%
(34)		A&E 4NCP Allocator (Ameren)	52.53%	10.93%	28.71%	7.50%	0.34%	100.00%
(35)	(33) - (34)	Difference	0.24%	-0.03%	0.05%	-0.25%	0.00%	

Source:
CCOS Spreadsheet, A.F.1 -- 4NCP
Ameren Missouri Response to MECG 2.1

Calculation of Reasonable CP-Based Allocators

	CP at the Generator (kW)													
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**		
Residential	2,986,120	3,192,925	2,241,345	2,336,112	2,390,117	3,396,685	3,783,274	3,720,541	2,959,177	1,810,299	2,539,401	3,250,373		
SGS	681,996	589,137	497,452	344,345	622,363	690,346	770,513	755,555	651,204	487,052	495,889	510,920		
LGS	1,410,147	1,348,438	1,021,429	939,796	1,154,802	1,326,601	1,437,696	1,377,867	1,221,104	1,019,123	1,054,258	1,004,661		
SP	523,077	528,403	469,084	473,737	551,379	540,752	587,996	585,266	556,477	489,167	479,898	400,980		
LPS	423,281	425,726	432,374	433,057	502,047	519,075	512,915	530,932	513,243	474,383	419,422	368,339		
Lighting	9,227	49	-	-	-	-	-	-	-	-	36,330	9,743		
Total	**6,033,847**	**6,084,677**	**4,661,685**	**4,527,047**	**5,220,708**	**6,473,460**	**7,092,395**	**6,970,160**	**5,901,205**	**4,280,023**	**5,025,198**	**5,545,016**		
Percent of Maximum	**85%**	**86%**	**66%**	**64%**	**74%**	**91%**	**100%**	**98%**	**83%**	**60%**	**71%**	**78%**		
System Peak Load Rank	**5**	**4**	**10**	**11**	**8**	**3**	**1**	**2**	**6**	**12**	**9**	**7**		
1CP													**Average**	**Allocator**
Residential							3,783,274						3,783,274	53.34%
SGS							770,513						770,513	10.86%
LGS/SP							2,025,693						2,025,693	28.56%
LPS							512,915						512,915	7.23%
Lighting							-						-	0.00%
Total							**7,092,395**						**7,092,395**	**100.00%**
Multiple Coincident Peak (5%)														
Residential							3,783,274	3,720,541					3,751,907	53.36%
SGS							770,513	755,555					763,034	10.85%
LGS/SP							2,025,693	1,963,133					1,994,413	28.36%
LPS							512,915	530,932					521,923	7.42%
Lighting							-	-					-	0.00%
Total							**7,092,395**	**6,970,160**					**7,031,278**	**100.00%**
Multiple Coincident Peak (10%)														
Residential						3,396,685	3,783,274	3,720,541					3,633,500	53.08%
SGS						690,346	770,513	755,555					738,805	10.79%
LGS/SP						1,867,353	2,025,693	1,963,133					1,952,059	28.52%
LPS						519,075	512,915	530,932					520,974	7.61%
Lighting						-	-	-					-	0.00%
Total						**6,473,460**	**7,092,395**	**6,970,160**					**6,845,338**	**100.00%**

Source:
Ameren Missouri Response to MECG 2.1

Calculation of Rate of Return Index Values

Customer Class	Rate of Return (%) (1)	RRI (2) (1) / (1) Total Company
Residential	3.10%	0.65
Small General Service	5.15%	1.08
Large General Service/Small Primary Service	7.35%	1.54
Large Primary Service	7.70%	1.62
Company Owned Lighting	9.02%	1.89
Customer Owned Lighting	-4.57%	(0.96)
Total Company	**4.76%**	**1.00**

The Midwest Energy Consumers Group
Exhibit SWC-8
Missouri File No. ER-2021-0240

Illustrative Example of MECG Proposed Revenue Allocation, $77 Million Reduction in Revenue Requirement from Ameren Proposed Increase

Customer Class	Normalized Retail Revenues	Ameren Proposed Base Revenue Requirement	Ameren Proposed Change	Revenue Neutral Shift Required to Reach Cost-Based Rates		50 Percent Of Reduction Used for Revenue Neutral Shift	50 Percent of Reduction Applied on an Equal Percentage Basis to All Classes	Total Revenue Change		Reduction in Subsidy
Residential	$ 1,273,043,176	$ 1,424,590,115	$ 151,546,939				$ (19,595,577)	$ 131,951,362	10.4%	
Small General Service	$ 274,247,507	$ 306,941,801	$ 32,694,294	$ (4,257,880)	4.5%	$ (1,729,828)	$ (4,221,411)	$ 26,743,055	9.8%	41%
Large General Service	$ 507,149,139	$ 567,788,047	$ 60,638,908	$ (46,330,076)	48.9%	$ (18,822,296)	$ (7,806,397)	$ 34,010,216	6.7%	41%
Small Primary Service	$ 220,416,108	$ 246,816,373	$ 26,400,265	$ (20,170,651)	21.3%	$ (8,194,633)	$ (3,392,800)	$ 14,812,832	6.7%	41%
Large Primary Service	$ 188,575,861	$ 211,084,406	$ 22,508,545	$ (17,855,234)	18.8%	$ (7,253,960)	$ (2,902,693)	$ 12,351,893	6.6%	41%
Company-Owned Lighting	$ 35,639,800	$ 39,844,649	$ 4,204,849	$ (6,182,552)	6.5%	$ (2,511,755)	$ (548,593)	$ 1,144,501	3.2%	41%
Customer-Owned Lighting	$ 2,848,591	$ 3,256,954	$ 408,363				$ (43,848)	$ 364,515	12.8%	
Metropolitan Sewer District	$ 74,966	$ 83,955	$ 8,989				$ (1,154)	$ 7,835	10.5%	
Total	**$ 2,501,995,148**	**$ 2,800,406,300**	**$ 298,411,152**	**$ (94,796,393)**		**$ (38,512,472)**	**$ (38,512,472)**	**$ 221,386,208**		

Staff Proposed Revenue Requirement Increase	**$ 221,386,208**
Reduction from Ameren Proposed	**$ 77,024,944**
50 Percent of Reduction Used for Revenue Neutral Shift	**$ 38,512,472**
50 Percent of Reduction Applied to All Classes on an Equal % Basis	**$ 38,512,472**
Equal Percentage Reduction	**1.5%**

Sources:

Direct Testimony of Lisa M. Ferguson, page 10, line 16

The Midwest Energy Users Group
Exhibit SWC-9
Missouri File No. ER-2021-0240

Meter:
Rate Class: 006
Description: Total kWh
Location:

Service Period Start Date: 09/16/20 Service Period End Date: 10/15/20

ELECTRIC SERVICE:
AssignID:003
Classification of RATE

Rate Class: 006
Description: Rate 3M Large General Service
Location:

Service Period Start Date: 09/16/20 Service Period End Date: 10/15/20

CHARGES:

Amount	Rate	Unit Of Mea	Quantity	Description
	.0356	KWH		Seasonal Energy Charge
	2	KW		Demand Charge
	.0609	KWH		Base Energy Charge / Hours Used
	.0452	KWH		Base Energy Charge / Hours Used
	.0356	KWH		Base Energy Charge / Hours Used
				Customer Charge

ALLOWANCE:

Amount	Rate	Unit Of Mea	Quantity	Description
	-.0019768	KWH		Fuel Adjustment Charge

CHARGES:

Amount	Rate	Unit Of Mea	Quantity	Description
	0	KWH		Energy Efficiency Investment Charge
	.00044	KWH		Renewable Energy Adjustment

NON-CHARGES:

Amount	Rate	Unit Of Mea	Quantity	Description
				Missouri State Sales Tax
TAXES:	STATE SALES TAX			
				Missouri Local Sales Tax
TAXES:	LS			
				Municipal Charge - Service
TAXES:	MUNICIPAL CHARGE			

*** TOTAL DUE:

Cost of Service by Function, Ameren Cost of Service Study Results, Proposed LGS and SP Rates

Function	Function		Large General Service Revenue by Function Proposed		Small Primary Service Revenue by Function Proposed	
	($) (1)	(%) (2) (1) / Total	($) (3)	(%) (4) (3) / Total	($) (5)	(%) (6) (5) / Total
Customer	$ 18,762	2.5%	$ 13,563	2.4%	$ 2,903	1.18%
Production - Demand	*$ 389,287*	*52.8%*				
Transmission - Demand	*$ 61,455*	*8.3%*				
Distribution - Demand	*$ 114,789*	*15.6%*				
Total Demand	$ 565,531	76.7%	$ 79,558	14.0%	$ 23,625	9.57%
Energy	$ 153,373	20.8%	$ 474,667	83.6%	$ 220,289	89.25%
Total Non-EE Revenue	**$ 737,666**	**100.00%**	**$ 567,788**	**100.0%**	**$ 246,816**	**100.0%**

Sources:
COSS Spreadsheet, Unbundled Tab
Exhibit SWC-10
Exhibit SWC-11

Derivation of Large General Service Revenue Requirement Using Ameren's Proposed Billing Units

LGS	Billing Units		Rates		Revenue
Customer Charge					
Standard	127,573	$	105.82	$	13,499,775
TOD Bills	501	$	126.91	$	63,582
Low Income Charge	128,074	$	0.78	$	99,898
Demand Charge					
Summer	7,727,878	$	6.04	$	46,676,383
Winter	14,679,337	$	2.24	$	32,881,715
Energy Charge					
Summer kWh					
First 150 HU	1,016,971,346	$	0.1085	$	110,341,391
Next 200 HU	1,089,830,895	$	0.0816	$	88,930,201
Over 350 HU	472,781,230	$	0.0549	$	25,955,690
On-Peak	5,617,128	$	0.0114	$	64,035
Off-Peak	10,806,297	$	(0.0065)	$	(70,241)
Winter kWh					
First 150 HU	1,654,392,691	$	0.0682	$	112,829,582
Next 200 HU	1,770,375,754	$	0.0506	$	89,581,013
Over 350 HU	770,481,446	$	0.0399	$	30,742,210
Seasonal Energy	408,429,624	$	0.0399	$	16,296,342
On-Peak	8,833,444	$	0.0035	$	30,917
Off-Peak	18,181,978	$	(0.0019)	$	(34,546)
Total kWh	7,183,262,986			$	567,887,946

Sources:
Schedule MWH-D3

Derivation of Small Primary Service Revenue Requirement Using Ameren's Proposed Billing Units

SP	Billing Units		Rates		Revenue
Customer Charge					
Standard	7,780	$	362.60	$	2,821,028
TOD Bills	213	$	383.68	$	81,724
Low Income Charge	7,993	$	0.78	$	6,235
Demand Charge					
Summer	2,785,023	$	5.21	$	14,509,970
Winter	5,131,169	$	1.89	$	9,697,909
Energy Charge					
Summer kWh					
First 150 HU	412,137,993	$	0.1053	$	43,398,131
Next 200 HU	499,538,596	$	0.0793	$	39,613,411
Over 350 HU	392,202,496	$	0.0532	$	20,865,173
On-Peak	12,988,331	$	0.0084	$	109,102
Off-Peak	28,721,453	$	(0.0048)	$	(137,863)
Winter kWh					
First 150 HU	670,717,761	$	0.0663	$	44,468,588
Next 200 HU	813,483,819	$	0.0492	$	40,023,404
Over 350 HU	631,304,723	$	0.0385	$	24,305,232
Seasonal Energy	198,851,110	$	0.0385	$	7,655,768
On-Peak	22,628,860	$	0.0031	$	70,149
Off-Peak	45,706,444	$	(0.0018)	$	(82,272)
Reactive Charge	1,310,772	$	0.39	$	511,201
Rider B					
115 kV	6,431	$	(1.51)	$	(9,711)
69 kV	847,321	$	(1.28)	$	(1,084,571)
Total kWh	3,618,236,498			$	246,822,607

Source:
Schedule MWH-D4

Derivation of Cost-Based Large General Service Wires Demand Charge

R1		LGS Base Revenue	$	567,788,048	
R2		Transmission Portion of Cost, Ameren CCOSS		8.33%	
R3	**R1 x R2**	Cost-Based Transmission Revenue Requirement	$	47,302,457	
R4		Demand Billing Determinants		22,407,215	kW
R5	**R3 / R4**	Cost-Based Transmission Demand Charge	$	2.11	/kW
R6		Distribution Portion of Cost, Ameren CCOSS		15.56%	
R7	**R1 X R6**	Cost-Based Distribution Revenue Requirement	$	88,354,109	
R8		Demand Billing Determinants		22,407,215	kW
R9	**R7 / R8**	Cost-Based Distribution Demand Charge	$	3.94	/kW
R10	**R5 + R9**	**Total Wires Distribution Charge**	**$**	**6.05**	**/kW**

Sources:
Exhibit SWC-10
Exhibit SWC-11

Calculation of Effective Demand Rates, Proposed LGS Summer

			Summer		Winter		Year Round	
(1)		Rate	LGS Summer					
(2)		Customer Demand	500	kW				
(3)		LGS Non-EE Revenues	$ 276,418,578		$ 291,369,470		$ 567,788,048	
(4)		% Energy, Cost of Service Study	20.8%		20.8%		20.8%	
(5)	(3) x (4)	Non-EE Energy Revenues, COS	$ 57,472,008		$ 60,580,547		$ 118,052,555	
(6)		Total Billing kWh	2,579,583,471	kWh	4,603,679,515	kWh	7,183,262,986	kWh
(7)	(5) / (6)	Cost of Service Energy Rate	$ 0.02228	/kWh	$ 0.01316	/kWh	$ 0.01643	/kWh
(8)		Proposed Billing Demand Rate (BDR)	$ 6.04	/kW	$ 2.24	/kW		/kW
(9)		% Demand, Cost of Service Study	76.7%		76.7%		76.7%	
(10)	(3) x (9)	Non-EE Demand Revenues, COS	$ 211,916,063		$ 223,378,152		$ 435,294,216	
(11)		Total Billing kW	7,727,878	kW	14,679,337	kW	22,407,215	kW
(12)	(10) / (11)	Full Cost Demand Rate (FCDR)	$ 27.42	/kW	$ 15.22	/kW	$ 19.43	/kW

(13)

Hours of Use	kWh	Load Factor	Proposed Energy Rate	Cost of Service Energy Rate	Demand Portion of Energy Rate	Billed Demand Cost from Energy Rate	Effective Demand Rate from Energy Rate	Total Demand Rate	Effective Subsidy (Received) / Paid
		(%)	($/kWh)	($/kWh)	($/kWh)	($)	($/kW)	($/kW)	($/kW)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
			Ex SWC-11		(4) - (5)		(7) / kW Demand	(8) + BDR	(9) - FCDR
1	500	0.1%	$ 0.10850	$ 0.02228	$ 0.08622	$ 43	$ 0.09	$ 6.13	$ (21.30)
100	50,000	13.9%	$ 0.10850	$ 0.02228	$ 0.08622	$ 4,311	$ 8.62	$ 14.66	$ (12.76)
200	100,000	27.8%	$ 0.08160	$ 0.02228	$ 0.05932	$ 7,950	$ 15.90	$ 21.94	$ (5.48)
292	146,000	40.6%	$ 0.08160	$ 0.02228	$ 0.05932	$ 10,678	$ 21.36	$ 27.40	$ (0.03)
293	146,500	40.7%	$ 0.08160	$ 0.02228	$ 0.05932	$ 10,708	$ 21.42	$ 27.46	$ 0.03
300	150,000	41.7%	$ 0.08160	$ 0.02228	$ 0.05932	$ 10,916	$ 21.83	$ 27.87	$ 0.45
400	200,000	55.6%	$ 0.05490	$ 0.02228	$ 0.03262	$ 13,214	$ 26.43	$ 32.47	$ 5.05
500	250,000	69.4%	$ 0.05490	$ 0.02228	$ 0.03262	$ 14,845	$ 29.69	$ 35.73	$ 8.31
600	300,000	83.3%	$ 0.05490	$ 0.02228	$ 0.03262	$ 16,476	$ 32.95	$ 38.99	$ 11.57
700	350,000	97.2%	$ 0.05490	$ 0.02228	$ 0.03262	$ 18,107	$ 36.21	$ 42.25	$ 14.83
720	360,000	100.0%	$ 0.05490	$ 0.02228	$ 0.03262	$ 18,433	$ 36.87	$ 42.91	$ 15.48

Sources:
Exhibit SWC-10
Exhibit SWC-11

Calculating Base Rate Portion of a Summer LGS Bill (Ameren Proposed Rates)

Energy and Demand Data				
Billing Period kWh			291,840	kWh
Billing Period kW			539	kW
Step 1: Determine applicable billing demands				
Immediately Preceding May Total Billing Demand			N/A	kW
Immediately Preceding October Total Billing Demand			N/A	kW
Immediately Preceding Maximum Summer Month Billing Demand			N/A	kW
Base Billing Demand			N/A	kW
Seasonal Billing Demand			N/A	kW
Total Billing Demand = Billing Period kW			539	kW
Step 2: Calculate first energy block kWh (first 150 kWh/kW)				
Billing Period kWh			291,840	kWh
Total Billing Demand			539	kW
Total Billing Demand X 150			80,850	kWh
If Billing Period kWh > Total Billing Demand X 150, First Block is Total Billing Demand X 150			80,850	kWh
If Billing Period kWh < Total Billing Demand X 150, First Block is Billing Period kWh			N/A	kWh
Step 3: Calculate second energy block kWh (next 200 kWh/kW)				
Billing Period kWh			291,840	kWh
Total Billing Demand			539	kW
Total Billing Demand X 200			107,800	kWh
Total Billing Demand X 350			188,650	kWh
If Billing Period kWh > Total Billing Demand X 350, Second Block is Total Billing Demand X 200			107,800	kWh
If Billing Period kWh < Total Billing Demand X 350, Second Block is Billing Period kWh - First Block kWh			N/A	kWh
Step 4: Calculate third energy block kWh (all kWh over 350 kWh/kW)				
Billing Period kWh			291,840	kWh
Total Billing Demand			539	kW
Total Billing Demand X 350			188,650	kWh
If Billing Period kWh > Total Billing Demand X 350, Third Block is Billing Period kWh - First Block kWh - Second Block kWh			103,190	kWh
If Billing Period kWh < Total Billing Demand X 350, There are No kWh in the Third Block			N/A	kWh
Billing Determinants				
Total Billing Demand			539	kW
First Block Energy			80,850	kWh
Second Block Energy			107,800	kWh
Third Block Energy			103,190	kWh
Billing Period kWh (For FAC, EEIC, and REA)			291,840	kWh
Step 5: Multiply Base Rate Charges by Billing Determinants				
Summer Demand Charge ($/kW)	$	6.04	539	$ 3,255.56
Energy Charge, First 150 kWh/kW ($/kWh)	$	0.1085	80,850	$ 8,772.23
Energy Charge, Next 200 kWh/kW ($/kWh)	$	0.0816	107,800	$ 8,796.48
Energy Charge, All kWh Over 350 kWh/kW ($/kWh)	$	0.0549	103,190	$ 5,665.13
Total Base Rate Cost				**$ 26,489.40**

Calculating Base Rate Portion of a Winter LGS Bill (Ameren Proposed Rates)

Energy and Demand Data				
Billing Period kWh			204,480	kWh
Billing Period kW			415	kW
Step 1: Determine applicable billing demands				
Immediately Preceding May Total Billing Demand			407	kW
Immediately Preceding October Total Billing Demand			421	kW
Immediately Preceding Maximum Summer Month Billing Demand			538	kW
Base Billing Demand = Min(Billing Period kW, May kW, October kW, Max Summer kW)			407	kW
Seasonal Billing Demand = Billing Period kW - Base Billing Demand kW			8	kW
Total Billing Demand = Billing Period kW			415	kW
Step 2: Determine seasonal energy				
Seasonal Billing Demand			8	kW
Total Billing Demand			415	kW
Seasonal Billing Demand % of Total Billing Demand			1.9%	
Billing Period kWh			204,480	kWh
Seasonal Energy			3,787	kWh
Remaining Energy for Blocking			200,693	kWh
Step 3: Calculate first energy block kWh (first 150 kWh/kW of Base Billing Demand)				
Remaining Energy for Blocking			200,693	kWh
Base Billing Demand			407	kW
Base Billing Demand X 150			61,056	kWh
If Billing Period kWh > Base Billing Demand X 150, First Block is Base Billing Demand X 150			61,056	kWh
If Billing Period kWh < Base Billing Demand X 150, First Block is Billing Period kWh			N/A	kWh
Step 4: Calculate second energy block kWh (next 200 kWh/kW of Base Billing Demand)				
Remaining Energy for Blocking			200,693	kWh
Base Billing Demand			407	kW
Base Billing Demand X 200			81,408	kWh
Base Billing Demand X 350			142,464	kWh
If Billing Period kWh > Base Billing Demand X 350, Second Block is Base Billing Demand X 200			81,408	kWh
If Billing Period kWh < Base Billing Demand X 350, Second Block is Billing Period kWh - First Block kWh			N/A	kWh
Step 5: Calculate third energy block kWh (all kWh over 350 kWh/kW)				
Remaining Energy for Blocking			200,693	kWh
Base Billing Demand			407	kW
Base Billing Demand X 350			142,464	kWh
If Billing Period kWh > Base Billing Demand X 350, Third Block is Billing Period kWh - First Block kWh - Second Block kWh			58,229	kWh
If Billing Period kWh < Base Billing Demand X 350, There are No kWh in the Third Block			N/A	kWh
Billing Determinants				
Total Billing Demand			415	kW
First Block Energy			61,056	kWh
Second Block Energy			81,408	kWh
Third Block Energy			58,229	kWh
Seasonal Energy			3,787	kWh
Billing Period kWh (For FAC, EEIC, and REA)			204,480	kWh
Step 6: Multiply Base Rate Charges by Billing Determinants				
Winter Demand Charge ($/kW)	$	2.24	415	$ 928.97
Energy Charge, First 150 kWh/kW ($/kWh)	$	0.0682	61,056	$ 4,164.02
Energy Charge, Next 200 kWh/kW ($/kWh)	$	0.0506	81,408	$ 4,119.24
Energy Charge, All kWh Over 350 kWh/kW ($/kWh)	$	0.0399	58,229	$ 2,323.35
Seasonal Energy Charge, Seasonal kWh	$	0.0399	3,787	$ 151.09
Total Base Rate Cost				**$ 11,686.68**

Derivation of MECG Proposed Rate Design for Large General Service at Ameren's Proposed Revenue Requirement

Current Retail Revenues	$ 507,149,139
Proposed Base Revenue Requirement	$ 567,788,047
% Class Increase	11.96%
3X Class Increase	35.87%

LGS	Billing Units	Present Rates	Proposed Rates	Revenue	Adjust Demand Charges by 3X and Accept Customer and On-Peak/Off-Peak Propsed Changes		% of Energy Charge Revenue	Adjusted Energy Charge Revenues	Resulting Energy Rates
Customer Charge									
Standard	127,573	$ 94.51	$ 105.82	$ 13,499,775	$ 105.82	$ 13,499,775			
TOD Bills	501	$ 115.59	$ 126.91	$ 63,582	$ 126.91	$ 63,582			
Low Income Charge	128,074	$ 0.78	$ 0.78	$ 99,898	$ 0.78	$ 99,898			
Demand Charge									
Summer	7,727,878	$ 5.40	$ 6.04	$ 46,676,383	$ 7.34	$ 56,699,478			
Winter	14,679,337	$ 2.00	$ 2.24	$ 32,881,715	$ 2.72	$ 39,889,765			
Energy Charge									
Summer kWh									
First 150 HU	1,016,971,346	$ 0.0969	$ 0.1085	$ 110,341,391			23.2%	$ 106,382,399	$ 0.1046
Next 200 HU	1,089,830,895	$ 0.0729	$ 0.0816	$ 88,930,201			18.7%	$ 85,739,431	$ 0.0787
Over 350 HU	472,781,230	$ 0.0491	$ 0.0549	$ 25,955,690			5.5%	$ 25,024,413	$ 0.0529
On-Peak	5,617,128	$ 0.0114	$ 0.0114	$ 64,035	$ 0.0114	$ 64,035			
Off-Peak	10,806,297	$ (0.0065)	$ (0.0065)	$ (70,241)	$ (0.0065)	$ (70,241)			
Winter kWh									
First 150 HU	1,654,392,691	$ 0.0609	$ 0.0682	$ 112,829,582			23.8%	$ 108,781,314	$ 0.0658
Next 200 HU	1,770,375,754	$ 0.0452	$ 0.0506	$ 89,581,013			18.9%	$ 86,366,893	$ 0.0488
Over 350 HU	770,481,446	$ 0.0356	$ 0.0399	$ 30,742,210			6.5%	$ 29,639,195	$ 0.0385
Seasonal Energy	408,429,624	$ 0.0356	$ 0.0399	$ 16,296,342			3.4%	$ 15,711,638	$ 0.0385
On-Peak	8,833,444	$ 0.0035	$ 0.0035	$ 30,917	$ 0.0035	$ 30,917			
Off-Peak	18,181,978	$ (0.0019)	$ (0.0019)	$ (34,546)	$ (0.0019)	$ (34,546)			
Total kWh	7,183,262,986			$ 567,887,946		$ 110,242,663			
					Remaining Revenue	$ 457,645,283			

Sources:
Exhibit SWC-3
Exhibit SWC-11