

Exhibit No. 215

Commission Staff – Exhibit 215
Sarah L.K. Lange
Rebuttal Testimony
File Nos. ER-2021-0240 & GR-2021-0241

Exhibit No.:
Issue(s): *Rate Design*
Class Cost of Service
Witness: *Sarah L.K. Lange*
Sponsoring Party: *MoPSC Staff*
Type of Exhibit: *Rebuttal Testimony*
Case No.: *ER-2021-0240*
Date Testimony Prepared: *October 15, 2021*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

REBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

CASE NO. ER-2021-0240

Jefferson City, Missouri
October 2021

1
2
3
4
5
6
7
8
9
10
11

**TABLE OF CONTENTS OF
REBUTTAL TESTIMONY OF
SARAH L.K. LANGE
UNION ELECTRIC COMPANY
d/b/a Ameren Missouri
CASE NO. ER-2021-0240**

Class Cost of Service and Revenue Responsibilities.....2
MECG and MIEC Testimonies3
Distribution Allocations.....21
Summary and Conclusion regarding Distribution Allocation34

1 **REBUTTAL TESTIMONY**

2 **OF**

3 **SARAH L.K. LANGE**

4 **UNION ELECTRIC COMPANY**
5 **d/b/a Ameren Missouri**

6 **CASE NO. ER-2021-0240**

7
8 Q. Please state your name.

9 A. My name is Sarah Lange.

10 Q. Are you the same Sarah Lange that contributed to Staff's CCoS and Rate
11 Design Report?

12 A. Yes.

13 Q. Do you have any changes or updates to make to that the sections you authored?

14 A. Yes. At page 56 of the Staff Report I stated that "the RESRAM and FAC
15 recovery for February 2021 will each begin February 1 of 2022, which is likely to be at or near
16 the time of the Commission's Report and Order in the rate case, and potentially between the
17 issuance of the Order and the compliance tariffs." The FAC Recovery Period covering
18 February 2021 began October 1, 2021.

19 Q. What is the purpose of your rebuttal testimony, and how is it organized?

20 A. I will first identify how the Ameren Missouri's CCoS study does not indicate
21 that it is appropriate to make revenue neutral shifts in revenue responsibility outside of the
22 lighting classes in this case, even if it is reliable enough for evidentiary use in this case. I will
23 then address the rate design recommendations of Mr. Chriss on behalf of Midwest Energy
24 Consumers Group ("MECG") and Mr. Brubaker on behalf of Midwest Industrial
25 Energy Consumers ("MIEC") and address some of the more blatantly misleading

1 characterizations in these testimonies for the reference of Commissioners. I will identify flaws
2 in the Ameren Missouri CCoS study that undermine its evidentiary reliability, and indicate the
3 direction of the impact of the flaws to facilitate its consideration, if necessary. Finally, I will
4 identify reasonable improvements to the form of the data retained by Ameren Missouri to
5 mitigate the poor study quality in future cases.

6 **CLASS COST OF SERVICE AND REVENUE RESPONSIBILITIES**

7 Q. What are the results of Ameren Missouri's class cost of service study?

8 A. Ameren Missouri's study indicates that all classes other than Customer Owned
9 lighting are providing revenues that exceed allocated expenses, and are contributing towards
10 rate of return. Staff reviewed the level of over or under-contribution of each class to Ameren
11 Missouri's revenue requirement as a percent of rate revenue to determine whether any classes
12 were contributing outside of the +/- 5% range Staff has typically relied on for recommended
13 revenue neutral shifts to class revenue responsibility. While the Customer Owned Lighting
14 class was found to be outside of this threshold at a 10% under-contribution, no other class was
15 outside of this range which would trigger a shift recommendation.

16

	Residential	SGS	LGS/SPS	LPS	Co. Owned Lighting	Cust. Owned Lighting
Allocated Revenues:	\$ 190,455,332	\$ 41,396,996	\$ 135,073,308	\$ 41,824,724	\$ 1,757,517	\$ 551,535
Total Expenses:	\$ 1,289,839,375	\$ 258,628,745	\$ 673,615,489	\$ 183,519,424	\$ 24,287,640	\$ 4,180,205
Rate Revenue:	\$ 1,273,043,176	\$ 274,322,474	\$ 727,565,247	\$ 188,575,861	\$ 35,639,800	\$ 2,848,591
Available Return:	\$ 173,659,133	\$ 57,090,725	\$ 189,023,066	\$ 46,881,161	\$ 13,109,677	\$ (780,079)
Rate Base:	\$ 5,601,035,696	\$ 1,108,885,033	\$ 2,571,566,786	\$ 609,212,234	\$ 145,390,336	\$ 17,085,077
Return as Percent of Net Ratebase:	3.10%	5.15%	7.35%	7.70%	9.02%	-4.57%
Required Return at System Average RoR:	\$ 391,792,447	\$ 77,566,508	\$ 179,881,097	\$ 42,614,396	\$ 10,170,054	\$ 1,195,101
Required Return plus Expenses net of Other Revenue:	\$ 1,491,176,490	\$ 294,798,257	\$ 718,423,277	\$ 184,309,095	\$ 32,700,177	\$ 4,823,771
% Change to Rate Revenues to Achieve System Average RoR:	17.13%	7.46%	-1.26%	-2.26%	-8.25%	69.34%
kWh:	14,454,221,713	3,278,305,271	11,488,103,967	3,689,239,273	85,330,142	45,767,767
Start \$/kWh:	\$ 0.0881	\$ 0.0837	\$ 0.0633	\$ 0.0511	\$ 0.4177	\$ 0.0622
End \$/kWh:	\$ 0.1032	\$ 0.0899	\$ 0.0625	\$ 0.0500	\$ 0.3832	\$ 0.1054
Class Increase at System Average Increase:	\$ 114,093,750	\$ 24,585,560	\$ 65,206,466	\$ 16,900,705	\$ 3,194,140	\$ 255,299
Available Return with System Average Increase:	\$ 287,752,883	\$ 81,676,285	\$ 254,229,533	\$ 63,781,866	\$ 16,303,817	\$ (524,781)
% Over/Under Contribution @ System Average:	1.86%	-0.37%	-2.89%	-3.47%	-4.22%	10.07%

17
18 Q. Which other parties performed Class Cost of Service Studies?

1 A. None but Staff. MIEC relies on Ameren Missouri's study with slight
2 modifications. MECG's workpapers are somewhat unclear as to whether they directly relied on
3 Ameren Missouri's study or made slight modifications related to production allocation. Other
4 parties make policy-based recommendations.

5 **MECG AND MIEC TESTIMONIES**

6 Q. What rate design recommendations are made by MIEC witness,
7 Mr. Maurice Brubaker?

8 A. In his direct testimony at page 4, Mr. Brubaker states, "For purposes of
9 implementing the final rates in this case, all of the charges in the Large Primary Service Rate,
10 except for the Low-Income Pilot Program Charge, should receive the same percentage change."

11 Q. Mr. Brubaker includes statements such as "There will be many hours during the
12 day or during the year when not all of this generating capacity will be needed. Nevertheless, it
13 must be in place to meet the peak demands on the system. Thus, production plant investment is
14 usually classified as demand-related. Regardless of how production plant investment is
15 classified, the associated capital costs (which include return on investment, depreciation,
16 fixed O&M expenses, taxes and insurance) are fixed; that is, they do not vary with the
17 amount of kWhs generated and sold. These fixed costs are determined by the amount of
18 capacity (i.e., kW) that the utility must install to satisfy its obligation-to-serve requirement. On
19 the other hand, it is easy to see that the amount of fuel burned – and therefore the amount of
20 fuel expense – is closely related to the amount of energy (number of kWhs) that customers use.
21 Therefore, fuel expense is an energy-related cost."¹ Is this testimony relevant to Ameren
22 Missouri in the year 2021?

¹ See Brubaker testimony at page 4.

1 A. No. A relevant discussion is found in the handbook "Electric Cost Allocation
2 for a New Era," ("RAP Manual") by Jim Lazar, Paul Chernick and William Marcus, edited by
3 Mark LeBel, (attached as Schedule SLKL-r1.) at page 17:

4 The key texts and most of the analytical principles currently used for cost
5 allocation were developed between the 1960s and early 1990s. Since that
6 time, the electric system in the United States has been undergoing another
7 period of dramatic change. That includes a wide range of interrelated
8 advancements in technology, policy and economics:

- 9 • Major advances in data collection and analytical capabilities.
- 10 • Restructuring of the industry in many parts of the country, including new
11 wholesale electricity markets, new retail markets and new market
12 participants.
- 13 • New consumer interests and technologies that can be deployed **behind the**
14 **meter**, including clean **distributed generation**, **energy efficiency**,
15 **demand response**, storage and other energy management technologies.
- 16 • Dramatic shifts in the relative cost of technologies and fuels, including
17 massive declines in the price of **variable renewable resources** like wind
18 and solar and sharp declines in the cost of energy storage technologies.
- 19 • The potential for beneficial electrification of end uses that currently run
20 directly on fossil fuels — for example, electric vehicles in place of vehicles
21 with internal combustion engines.

22 Many, if not all, of these changes have quantifiable elements that can and
23 should be incorporated directly into the regulatory process, including cost
24 allocation. The increased development of renewable energy and the
25 proliferation of more sophisticated meters provide two examples. Figure 3
26 illustrates the dramatic increase in wind and solar generation in the United
27 States in the last decade, based on data from the U.S. Energy Information
28 Administration. Traditional cost allocation techniques classify all utility
29 costs as **energy-related**, **demand-related** or **customer related**. These
30 categories were always simplifications, but they must be reevaluated given
31 new developments. Some legacy cost allocation methods would have
32 treated wind and solar generation entirely as a demand-related cost simply
33 because they are capital investments without any variable **fuel costs**.
34 However, wind and solar generation does not necessarily provide firm
35 **capacity** at peak times as envisioned by the legacy frameworks, and it
36 displaces the need for fuel supply, so it doesn't fit as a demand-related cost.

37 ****

38 In the end, cost allocation may be more of an art than a science, since
39 fairness and equity are often in the eye of the beholder. In most situations,

1 cost allocation is a zero-sum process where lower costs for any one group
2 of customers lead to higher costs for another group. However, the
3 techniques used in cost allocation have been designed to mediate these
4 disputes between competing sets of interests. Similarly, the data and
5 analysis produced for the cost allocation process can also provide
6 meaningful information to assist in rate design, such as the seasons and
7 hours when costs are highest and lowest, categorized by system component
8 as well as by customer class.

9 In that spirit, we would like to highlight the following current best practices
10 discussed at more length in the later chapters of this manual. To begin, there
11 are best practices that apply to both embedded and marginal cost of service
12 studies:

- 13 • Treat as customer-related only those costs that actually vary with the
14 number of customers, generally known as the basic customer method.
- 15 • Apportion all shared generation, transmission and distribution assets and
16 the associated operating expenses on measures of usage, both energy- and
17 demand-based.
- 18 • Ensure broad sharing of overhead investments and administrative and
19 general (A&G) costs, based on usage metrics.
- 20 • Eliminate any distinction between “fixed” costs and “variable” costs, as
21 capital investments (including new technology and data acquisition) are
22 increasingly substitutes for fuel and other short-run variable operating costs.
- 23 • Where future costs are expected to vary significantly from current costs,
24 make the cost trajectory an important consideration in the apportionment of
25 costs.

26 Second, there are current best practices specific to embedded cost of service
27 studies:

- 28 • Classify and allocate generation capacity costs using a time-differentiated
29 method, such as the probability-of dispatch or base-intermediate-peak (BIP)
30 methods, or classify capacity costs between energy and demand using the
31 equivalent peaker method.
- 32 • Allocate demand-related costs for generation using a broad peak measure,
33 such as the highest 100 hours or the loss-of-energy expectation.
- 34 • Classify and allocate the costs of transmission based on its purpose, with
35 any demand-related costs allocated based on broad peak periods for regional
36 networks and narrower ones for local networks.
- 37 • Classify distribution costs using the basic customer method, and divide the
38 vast majority of costs between demand-related and energy-related using an
39 energy weighted method, such as the average-and-peak method that many
40 natural gas utilities use.
41

Rebuttal Testimony of
Sarah L.K. Lange

- 1 • Allocate demand-related distribution costs using appropriately broad peak
- 2 measures that capture the hours with high usage for the relevant system
- 3 elements while appropriately accounting for diversity in customer usage.
- 4 • Ensure that customer connection and service costs appropriately reflect
- 5 differences between customer classes by using either specific cost studies
- 6 for each element or a weighted customer approach.
- 7 • Functionalize and classify AMI and billing systems according to their
- 8 multiple benefits across different elements and aspects of the electric
- 9 system.

10 Further, at page 21, the RAP Manual includes the following “All shared distribution costs
11 should be apportioned based on the time periods when customers utilize these facilities. The
12 system is needed to provide service in every hour, and in most cases a significant portion of the
13 distribution system cost should be assigned volumetrically to all hours across the year.”

14 Q. At page 41 Mr. Brubaker states “Moving 50% of the way toward cost of service
15 requires a Residential class revenue-neutral adjustment of only 3.9% (as compared to the 7.8%
16 increase required to move all the way to cost of service) is relatively moderate....” What cost
17 of service is he discussing moving towards?

18 A. Mr. Brubaker is discussing the revenue responsibility changes to cause the
19 Residential class to contribute equally to the rate of return proposed by Ameren Missouri in its
20 direct filing.

21 Q. Does MIEC recommend the Commission approve the revenue requirement or
22 cost of service requested by Ameren Missouri?

23 A. No. MIEC witness Greg Meyer recommends reduction of Ameren Missouri’s
24 requested revenue requirement by “at least \$56 million,” at page 4 of his direct testimony.

25 Q. What rate design recommendations are made by MECG witness,
26 Mr. Steve Chriss?

Rebuttal Testimony of
Sarah L.K. Lange

1 A. In his direct testimony at page 46, Mr. Chriss states,
2 For the purposes of this docket, at the Company's proposed revenue
3 requirement for the LGS and SP classes, MECG recommends that the
4 Commission:

5 1) Accept Ameren's proposed customer charges and on-peak and off-peak
6 adjusters for both LGS and SP, and Ameren's proposed Rider B credits and
7 reactive charge for SP;

8 2) Increase the summer and winter demand charges for LGS and SP by three
9 times the percent class increases; and

10 3) Apply the remaining proposed increase on an equal percentage basis to
11 the summer and winter energy charges.

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

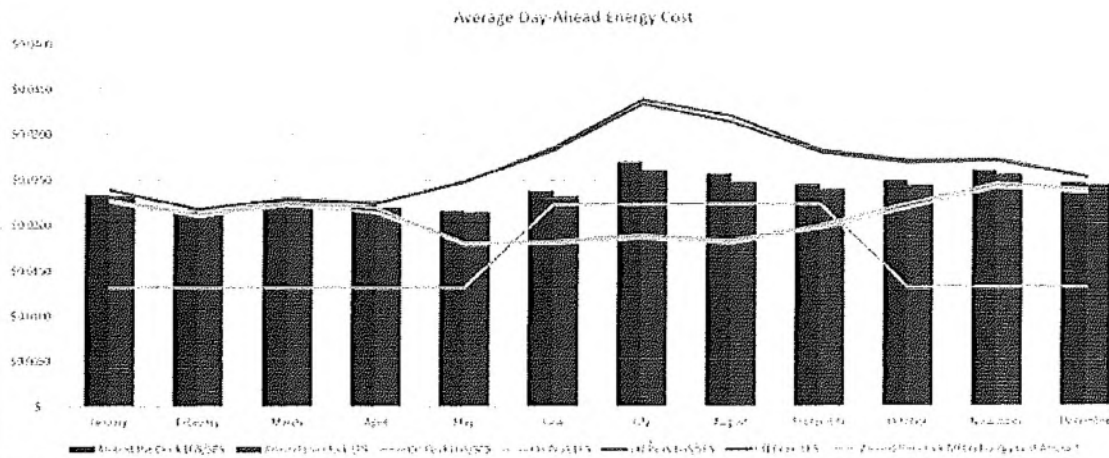
18 Q. At page 38 Mr. Chriss provides his estimates of cost-based energy charges for
19 LGS of \$0.02228/kWh for the summer period and \$0.01316/kWh for the winter period for
20 energy charges. Are these values reasonable?

21 A. No, these values would not recover the marginal cost of energy.

22 Q. What are the marginal costs of energy for LGS, SPS, and LPS customers?

Rebuttal Testimony of
Sarah L.K. Lange

1 A. The energy rate required to recover only the cost of market energy for LGS and
2 SPS customers is a year-round average of \$0.0275/kWh and \$0.0255/kWh for the LGS and SPS
3 rate schedules, respectively. The average Day-Ahead energy costs for the combined LGS and
4 SPS class and for the LPS class, both as a consumption-weighted around-the-clock average and
5 as the Rider I time-period energy costs,² are provided below:



7
8 Q. How does Mr. Chriss explain the difference between the cost to obtain energy
9 at wholesale to serve retail load and the amounts he recommends ideally be recovered through
10 the energy charge?

11 A. Mr. Chriss' direct testimony does not address this.

12 Q. Mr. Chriss advocates for an increase in the percentage of LGS and SPS revenues
13 that are recovered from demand charges. How are demand charges collected from customers
14 within the LGS and SPS tariffs?

15 A. The relevant LGS Provisions are:

² For purposes of this graph, weekends and holidays are included with the relevant time period. Note, these amounts do not include Real Time market charges, Ancillary Service charges, or other charges that are assessed on measures of load.

Rebuttal Testimony of
Sarah L.K. Lange

1 a. Total Billing Demand The monthly Total Billing Demand shall be the
2 maximum metered demand during the current month or, where elected by
3 customer, the billing demand determined in accordance with Rider I, Off-Peak
4 Demand Provisions, but in no event less than 100 kW.

5 b. Base Billing Demand The monthly Base Billing Demand, used only to
6 apportion kilowatt-hours during the Company's winter billing season, shall be
7 the Total Billing Demand during customer's immediately preceding May,
8 October or maximum summer billing month, or customer's current winter
9 month's Total Billing Demand, whichever is less.

10 The relevant SPS provisions are:

11 a. Total Billing Demand The monthly Billing Demand shall be the
12 maximum demand established during peak hours or 50% of the maximum
13 demand established during off-peak hours, whichever is greater, but in no event
14 less than 100 kW. Peak hours and off-peak hours are defined as follows:
15 Peak hours: 10:00 A.M. to 10:00 P.M., Monday through Friday. Off-peak hours:
16 All other hours including the entire 24 hours of the following days: New Year's
17 Day, Independence Day, Thanksgiving Friday, Good Friday, Labor Day,
18 Christmas Eve Day, Memorial Day, Thanksgiving Day, Christmas Day, All
19 times stated above apply to the local effective time.

20 b. Base Billing Demand The monthly Base Billing Demand, used only to
21 apportion kilowatt-hours during the Company's winter billing season, shall be
22 the Total Billing Demand during customer's immediately preceding May,

Rebuttal Testimony of
Sarah L.K. Lange

1 October or maximum summer billing month, or customer's current winter
2 month's Total Billing Demand, whichever is less.

3 In other words, LGS customers who have not elected to participate in Rider I are billed based
4 on their monthly non-coincident peak ("NCP"), and the remaining LGS customers and
5 SPS customers are billed based on the greater of their on-peak monthly NCP or 50% of their
6 off-peak NCP. Additionally, the monthly NCP drives hours-use energy charge recovery.

7 Q. What is a customer's monthly NCP?

8 A. In simple terms, a monthly NCP is the highest demand a customer experienced
9 during a month. This demand is measured typically as the highest usage experienced during a
10 15 minute interval.

11 Q. Is a customer's monthly NCP indicative of that customer's causation of
12 generation, transmission, or distribution infrastructure or expenses?

13 A. Not really. Other than the very local distribution facilities that must be sized to
14 accommodate that customer's peak load, it would be only coincidental if a given customer's
15 NCP aligned with the drivers of generation, transmission, or distribution infrastructure.

16 Q. What is the relevance of a customer's NCP demand to the cost of Ameren
17 Missouri's generation capacity or MISO IM resource adequacy?

18 A. A customer's NCP demand is not relevant to Ameren Missouri's generation
19 capacity or MISO resource adequacy. The usage of a customer in the interval associated with
20 the system peak known as that customer's coincident peak is the only determinant relevant to
21 Ameren Missouri's MISO resource adequacy or generation capacity requirements. There may
22 have been a time where customer usage was so uniform that it could reasonably be assumed
23 that a customer's NCP demand would coincide with system peak, but that is certainly not the

Rebuttal Testimony of
Sarah L.K. Lange

1 case today. Therefore, it is no more reasonable to recover the costs associated with system peak
2 demands via a customer's NCP demand than it is to recover those costs via a customer's energy
3 consumption, and it is potentially less reasonable to do so.

4 Q. Mr. Chriss on pages 35 – 36 states “All of the Company's production demand
5 (capacity), transmission, and distribution demand costs should be recovered through demand
6 charges. These costs are fixed and incurred to serve customer kW demands on the system
7 regardless of how many kWh are consumed. Optimally the costs for each of the three functions
8 would be recovered through its own unbundled demand charge (or charges if time or seasonal
9 differentiation is appropriate) to best recover costs in a manner that reflects how those costs are
10 incurred and allocated.” Are these statements accurate?

11 A. No. First, no cost is truly “fixed” in a utility's revenue requirement. Some costs
12 and expenses vary with the amount of energy consumed, or the number of customers served, or
13 the amount of wholesale energy generated for sale, and some costs and expenses are relatively
14 stable. I do agree that best practice would be to better reflect unbundled cost causation in rates,
15 to the extent customer understandability is retained or enhanced. However, an NCP demand
16 charge is not an ideal recovery mechanism for the costs discussed by Mr. Chriss.

17 Q. Mr. Chriss recommends movement toward time-based rate structures; is this
18 consistent with Staff's recommendations in this case and related dockets?

19 A. Yes. However, his suggestion of moving additional revenue recovery away
20 from energy charges and into the NCP demand charges is counter-productive to that goal, and
21 has the potential to exacerbate customer confusion and lack of bill predictability preparing for
22 that transition. Staff is optimistic that the next Ameren Missouri rate case will present an
23 opportunity to fully redesign the non-residential rate structures to a modern rate structure as

Rebuttal Testimony of
Sarah L.K. Lange

1 described in Staff's Report on Distributed Energy Resources, in File No. EW-2017-0245.
2 Neither the NCP nor the hours use design are optimal for aligning cost causation and revenue
3 recovery, however, they are what customers are used to. Mr. Chriss's recommended shift to
4 increased NCP recovery isn't any better than the current design at aligning cost causation. The
5 proper direction to take in this case is to minimize customer impact from rate design to minimize
6 rate switching and customer confusion, both of which could complicate the imminent roll-out
7 of a better rate structure in the next rate case.

8 Q. Are Mr. Chriss's opinions on production capacity planning applicable to
9 Ameren Missouri's generation fleet as constituted in this case?³

10 A. No. The recent additions to the Ameren Missouri wind fleet were made to
11 enable production of REC certificates to comply with the Renewable Energy Standard, and the
12 legacy fleet existed to satisfy peaks established prior to the departure of a significant industrial
13 load that has left its system. The Commission's order in File No. EA-2018-0202 found that
14 "The wind generation project for which Ameren Missouri has been granted a CCN in this case is
15 intended to comply with the renewable energy mandates of the law."⁴ File No. EA-2019-0181
16 was resolved by a Stipulation and Agreement that included a provision that "The Signatories
17 agree the costs of this Project are Renewable Energy Standard compliance costs so long as the
18 facility is certified by DE as a renewable energy resource under 4 CSR 340-8.010."⁵ Not only
19 were these facilities not constructed to meet system peak capacity, these facilities were

³ See page 11 "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."

⁴ Finding of Fact #5, Report and Order page 5. This case concerned the High Prairie wind project.

⁵ Nonunanimous Stipulation and Agreement at page 2.

Rebuttal Testimony of
Sarah L.K. Lange

1 constructed to meet a statutory requirement that is based on the amount of annual energy sold
2 at retail.

3 Q. Mr. Chriss's Schedule 8 purports to provide a method to allocate the difference
4 between Staff's revenue requirement and Ameren Missouri's revenue requirement to the results
5 of Ameren Missouri's CCoS Study. Is this reasonable?

6 A. No. Of the approximately \$77 million in differences Mr. Chriss identifies
7 between Staff's Revenue Requirement and Ameren Missouri's revenue requirement,
8 approximately \$27 million is related to rate of return. Rate of return revenue responsibility is
9 allocated to customer classes as the product of the rate of return studied and the net rate base
10 allocated or assigned to each class. Applying Staff's recommended rate of return within the
11 Ameren Missouri study, reduces the class revenue responsibilities as provided in the
12 table below:

13

	Total Missouri	Residential	Small Gen Serv	Large G.S./ Sm Primary	Large Primary	Lighting
Net Rate Base	\$ 10,053,175,162	\$ 5,601,035,696	\$ 1,108,885,033	\$ 2,571,566,786	\$ 609,212,234	\$ 162,475,413
Ameren Rate of Return	\$ 703,219,603	\$ 391,792,447	\$ 77,586,508	\$ 179,881,097	\$ 42,814,396	\$ 11,365,155
Staff Rate of Return	\$ 676,076,030	\$ 376,669,651	\$ 74,572,519	\$ 172,937,866	\$ 40,969,523	\$ 10,926,472
\$ Difference	\$ (27,143,573)	\$ (15,122,796)	\$ (2,993,990)	\$ (6,943,230)	\$ (1,644,873)	\$ (438,684)
% of Difference	100.0%	55.7%	11.0%	25.8%	6.1%	1.6%

14

15 Mr. Chriss is advocating to use a high rate of return to target the Residential class for
16 above-average increases, but using a lower rate of return to distribute the below-average
17 increases. This is not reasonable.

18 Q. Have you adjusted the Ameren CCoS to provide the level of over and
19 under-contribution at the Staff-Recommended RoR?

Rebuttal Testimony of
Sarah L.K. Lange

1 A. Yes. The under/overcontributions remain within the bounds suggesting no
2 revenue-neutral shifts are necessary, and the % of class revenue results to exactly match the
3 class cost of service are closer to zero than in Ameren Missouri’s study:

4

	Residential	SGS	LGS/SPS	LPS	Co. Owned Lighting	Cust. Owned Lighting
Allocated Revenues:	\$ 190,455,332	\$ 41,396,996	\$ 135,073,308	\$ 41,824,724	\$ 1,757,517	\$ 551,535
Total Expenses:	\$ 1,289,839,375	\$ 258,628,745	\$ 673,615,489	\$ 183,519,424	\$ 24,287,640	\$ 4,180,205
Rate Revenue:	\$ 1,273,043,176	\$ 274,322,474	\$ 727,565,247	\$ 188,575,861	\$ 35,639,800	\$ 2,848,591
Available Return:	\$ 173,659,133	\$ 57,090,725	\$ 189,023,066	\$ 46,881,161	\$ 13,109,677	\$ (780,079)
Rate Base:	\$ 5,601,035,696	\$ 1,108,885,033	\$ 2,571,566,786	\$ 609,212,234	\$ 145,390,336	\$ 17,085,077
Return as Percent of Net Ratebase:	3.10%	5.15%	7.35%	7.70%	9.02%	-4.57%
Required Return at Staff-Recommended RoR:	\$ 376,669,651	\$ 74,572,519	\$ 172,937,866	\$ 40,969,523	\$ 9,777,500	\$ 1,148,971
Required Return plus Expenses net of Other Revenue:	\$ 1,476,053,694	\$ 291,804,267	\$ 711,480,047	\$ 182,664,222	\$ 32,307,623	\$ 4,777,641
% Change to Rate Revenues to Achieve System Average RoR:	15.95%	6.37%	-2.21%	-3.13%	-9.35%	67.72%
kWh:	14,454,221,713	3,278,305,271	11,488,103,967	3,689,239,273	85,330,142	45,767,767
Start \$/kWh:	\$ 0.0881	\$ 0.0837	\$ 0.0633	\$ 0.0511	\$ 0.4177	\$ 0.0622
End \$/kWh:	\$ 0.1021	\$ 0.0890	\$ 0.0619	\$ 0.0495	\$ 0.3786	\$ 0.1044
Class Increase at System Average Increase:	\$ 114,093,750	\$ 24,585,560	\$ 65,206,466	\$ 16,900,705	\$ 3,194,140	\$ 255,299
Available Return with System Average Increase:	\$ 287,752,883	\$ 81,676,285	\$ 254,229,533	\$ 63,781,866	\$ 16,303,817	\$ (524,781)
% Over/Under Contribution @ System Average:	1.59%	-0.64%	-3.16%	-3.74%	-4.49%	9.80%
Difference between available and system average RoR:	\$ 203,010,518	\$ 17,481,794	\$ (16,085,200)	\$ (5,911,638)	\$ (3,332,177)	\$ 1,929,051
% of Class Revenues:	15.9%	6.4%	-2.2%	-3.1%	-9.3%	67.7%

5

6 Note, these results do not address the remaining differences between Staff and Ameren
7 Missouri’s revenue requirements and CCoS studies, and do not account for the changes in
8 required taxes associated with the changes in ROR.

9 Q. On page 8 Mr. Chriss provides a table of what he states “show[s] that rates for
10 the LGS and SP[S] classes have been set well in excess of cost of service since the 2007 rate
11 case.” What does the table show?

12 A. Mr. Chriss’s table provides what appears to be the changes Ameren Missouri
13 identified in its CCoS Study in its direct filing in each indicated case to the current revenues of
14 the combined LGS and SPS classes to exactly match the combined LGS and SPS revenue
15 requirement in each case. The table shows Ameren Missouri’s position in various rate cases,
16 and nothing more.

Rebuttal Testimony of
Sarah L.K. Lange

1 Q MECG asserts that “analysis for FERC Form 1 data shows that between 2008
2 and 2020, and not inclusive of the increases proposed in the instant docket, Ameren’s reported
3 revenue per kWh sold to LGS customers has increased from \$0.0563/kWh to \$0.0772/kWh, an
4 increase of 37.1 percent.”⁶ Is the result of dividing the total dollars of revenue provided by
5 customers on a given rate schedule by the kWh sold to customers on that rate schedule ten years
6 ago relevant to any question before the Commission in this proceeding?

7 A. No. It may be informative for the Commission to review information related to
8 shifts in revenue responsibility between various customers on various rate schedules over time,
9 particularly as it relates to avoiding unnecessary rate switching or causing rate shock. However,
10 this metric is particularly unhelpful for considerations of class cost of service and rate design,
11 because it fails to account for the changing customer base (1) due to changes in customer
12 characteristics and (2) due to changes in the total numbers of customers receiving service
13 whether due to rate switching or due to customer growth/loss.

14 Q. In what ways does the metric of class-average revenue per kWh provide a
15 misleading signal concerning the bills experienced by customers within a class?

16 A. To illustrate the misleading signal provided by this metric, in the following
17 examples we will review the changes to the “LGS Average \$/kWh” produced by varying
18 customers and customer characteristics of a very small hypothetical class.

19

Example 1	Annual Bill	kWh	\$/kWh	Example 2a	Annual Bill	kWh	\$/kWh
LGS Customer 1	\$ 3,500	50,000	\$ 0.070	LGS Customer 1	\$ 7,000	100,000	\$ 0.070
LGS Customer 2	\$ 3,500	50,000	\$ 0.070	LGS Customer 2	\$ 3,500	50,000	\$ 0.070
LGS Customer 3	\$ 2,000	50,000	\$ 0.040	LGS Customer 3	\$ 2,000	50,000	\$ 0.040
LGS Customer 4	\$ 2,000	50,000	\$ 0.040	LGS Customer 4	\$ 2,000	50,000	\$ 0.040
LGS Average \$/kWh	\$ 11,000	200,000	\$ 0.055	LGS Average \$/kWh	\$ 14,500	250,000	\$ 0.058

20

⁶ Chriss direct, page 6.

Rebuttal Testimony of
Sarah L.K. Lange

1 In Example 1, the class-average revenue per kWh produced is \$0.055 per kWh. In Example 2a,
2 we see that Customer 1 has doubled usage. While the other customers' bills have not changed,
3 the LGS Average \$/kWh has increased to \$0.058. This result is reproduced below in
4 Example 2b, by the addition of another customer, LGS Customer 5.

5

Example 2b	Annual Bill	kWh	\$/kWh	Example 2c	Annual Bill	kWh	\$/kWh
LGS Customer 1	\$ 3,500	50,000	\$ 0.070	LGS Customer 1	\$ -	-	\$ 0.070
LGS Customer 2	\$ 3,500	50,000	\$ 0.070	LGS Customer 2	\$ 3,500	50,000	\$ 0.070
LGS Customer 3	\$ 2,000	50,000	\$ 0.040	LGS Customer 3	\$ 2,000	50,000	\$ 0.040
LGS Customer 4	\$ 2,000	50,000	\$ 0.040	LGS Customer 4	\$ 2,000	50,000	\$ 0.040
LGS Customer 5	\$ 3,500	50,000	\$ 0.070	LGS Average \$/kWh	\$ 7,500	150,000	\$ 0.050
LGS Average \$/kWh	\$ 14,500	250,000	\$ 0.058				

6

7 As in Example 1, in Example 2b, no other customer's bill has changed, but the class-average
8 revenue per kWh has increased by 5.45%. However, as illustrated in Example 2c, above, the
9 loss of Customer 1 results in a decrease of 9.1% to the class-average revenue per kWh.

10 Q. Is it likely that these changes in customer counts and customer characteristics
11 would result in changes in the costs allocated or assigned to the LGS class in the next rate case?

12 A. Yes. However, those potential changes would not impact the bills paid by
13 Customer 2, 3, and 4 until the rate schedule under which they are billed is changed. If the rates
14 are appropriately designed, and all else remained equal, it is likely that the bill changes
15 experienced by Customers 2, 3, and 4 would be minimal and reflect only the minor change in
16 the company's overall sales.

17 Q. Can changes to rate design in rate cases result in some customers paying higher
18 bills while other customers on the same rate schedule pay lower bills?

19 A. Yes. As illustrated in Example 3 below, not only can customers within a class
20 experience vastly different impacts from a rate case due to changes in rate design, but customers
21 can experience such impacts without change to the resulting class-average revenue per kWh.

Rebuttal Testimony of
Sarah L.K. Lange

1

	Example 1			Example 3			
	Annual Bill	kWh	\$/kWh	Annual Bill	kWh	\$/kWh	
LGS Customer 1	\$ 3,500	50,000	\$ 0.070	LGS Customer 1	\$ 3,850	50,000	\$ 0.077
LGS Customer 2	\$ 3,500	50,000	\$ 0.070	LGS Customer 2	\$ 3,500	50,000	\$ 0.070
LGS Customer 3	\$ 2,000	50,000	\$ 0.040	LGS Customer 3	\$ 2,000	50,000	\$ 0.040
LGS Customer 4	\$ 2,000	50,000	\$ 0.040	LGS Customer 4	\$ 1,650	50,000	\$ 0.033
LGS Average \$/kWh	\$ 11,000	200,000	\$ 0.055	LGS Average \$/kWh	\$ 11,000	200,000	\$ 0.055

2

3 In Example 3, Customer 1's bill was increased by 10%, Customer 4's bill was decreased by
4 17.5%, and the metric of class-average revenue per kWh remained unchanged.

5 Q. Is there a more reasonable means of reviewing the impact of the last 12 years of
6 Ameren Missouri rate cases on customers?⁷

7 A. While no metric is perfect, it is probably most useful to review the bills or
8 average \$/kWh that would be experienced by a given customer with that customer's
9 characteristics held constant over time. Given the size of Ameren Missouri's customer base
10 and classes, it is impossible to accurately summarize these impacts for all potential customers.
11 Further, it is possible that a customer would change rate schedules over this time due to changes
12 in the rate designs of the relative schedules.

13 To facilitate these comparisons, Staff created a set of Customer Profiles, and priced out
14 the bills for those customers from the final rates promulgated from each rate case since Case
15 No. ER-2007-0002. For example, the bills produced by the studied Residential Profiles are
16 provided below:

17

	ER-2007-0002	ER-2008-0318	ER-2010-0036	ER-2011-0028	ER-2012-0166	ER-2014-0258	ER-2016-0179	Temp. Tax Reduction	ER-2019-0335
Residential Flat	\$ 817	\$ 882	\$ 988	\$ 1,079	\$ 1,156	\$ 1,219	\$ 1,260	\$ 1,186	\$ 1,202
1,500 ft Home w/ Space Heat	\$ 1,015	\$ 1,098	\$ 1,230	\$ 1,346	\$ 1,443	\$ 1,525	\$ 1,577	\$ 1,480	\$ 1,505
Large Home AC only	\$ 1,161	\$ 1,257	\$ 1,408	\$ 1,542	\$ 1,653	\$ 1,748	\$ 1,808	\$ 1,699	\$ 1,734
Small Apt w/ Space Heat	\$ 840	\$ 907	\$ 1,016	\$ 1,110	\$ 1,188	\$ 1,254	\$ 1,299	\$ 1,224	\$ 1,247

18

⁷ MEEIA, RESRAM, and FAC charges are not reflected in the bills and average rates discussed throughout this testimony.

Rebuttal Testimony of
Sarah L.K. Lange

1 To facilitate comparisons across customers of very different sizes, Staff divided the total
2 bills described above by the kWh of each customer. This produces an experienced average
3 \$/kWh that can be displayed on a graph with a readable scale when comparing the bill one may
4 experience with a small apartment to the bill one may experience when participating in
5 substantial industrial manufacturing.

6 The experienced average \$/kWh by Customer Profile are provided below, as well as
7 an indication of the % change experienced from the final rates promulgated in Case No.
8 ER-2007-0002 to the tariffed rates in effect today. Percent changes in excess of 35% are
9 highlighted in red, and percent changes lower than 25% are highlighted in green.

10

	ER-2007-0002	ER-2008-0318	ER-2010-0036	ER-2011-0028	ER-2012-0166	ER-2014-0258	ER-2016-0179	Temp. Tax Reduction	ER-2019-0335	% Change
Residential Flat	\$ 0.068	\$ 0.073	\$ 0.082	\$ 0.090	\$ 0.096	\$ 0.102	\$ 0.105	\$ 0.099	\$ 0.100	47.2%
1,500 ft Home w/ Space Heat	\$ 0.065	\$ 0.070	\$ 0.079	\$ 0.086	\$ 0.093	\$ 0.098	\$ 0.101	\$ 0.095	\$ 0.097	48.3%
Large Home AC only	\$ 0.066	\$ 0.071	\$ 0.080	\$ 0.088	\$ 0.094	\$ 0.099	\$ 0.103	\$ 0.097	\$ 0.099	49.4%
Small Apt w/ Space Heat	\$ 0.070	\$ 0.076	\$ 0.085	\$ 0.092	\$ 0.099	\$ 0.104	\$ 0.108	\$ 0.102	\$ 0.104	48.6%
SGS Flat	\$ 0.067	\$ 0.072	\$ 0.081	\$ 0.085	\$ 0.091	\$ 0.095	\$ 0.099	\$ 0.093	\$ 0.092	37.2%
SGS 24 Hour Retail	\$ 0.063	\$ 0.068	\$ 0.076	\$ 0.080	\$ 0.085	\$ 0.089	\$ 0.092	\$ 0.087	\$ 0.086	37.0%
SGS Office Use with HVAC	\$ 0.065	\$ 0.070	\$ 0.079	\$ 0.083	\$ 0.089	\$ 0.093	\$ 0.096	\$ 0.091	\$ 0.090	37.1%
SGS 2nd Metered Residential	\$ 0.084	\$ 0.090	\$ 0.102	\$ 0.106	\$ 0.113	\$ 0.118	\$ 0.124	\$ 0.118	\$ 0.115	37.8%
Small LGS Low Load Factor Winter Peak	\$ 0.065	\$ 0.065	\$ 0.070	\$ 0.077	\$ 0.081	\$ 0.090	\$ 0.093	\$ 0.089	\$ 0.087	33.6%
Small LGS High Load Factor Winter Peak	\$ 0.044	\$ 0.044	\$ 0.047	\$ 0.052	\$ 0.055	\$ 0.061	\$ 0.063	\$ 0.058	\$ 0.058	30.9%
Small LGS Low Load Factor Flat Usage	\$ 0.068	\$ 0.068	\$ 0.073	\$ 0.080	\$ 0.084	\$ 0.094	\$ 0.097	\$ 0.093	\$ 0.091	33.5%
Small LGS High Load Factor Flat Usage	\$ 0.044	\$ 0.044	\$ 0.047	\$ 0.052	\$ 0.055	\$ 0.061	\$ 0.063	\$ 0.058	\$ 0.058	30.9%
Large LGS Low Load Factor Winter Peak	\$ 0.069	\$ 0.069	\$ 0.074	\$ 0.082	\$ 0.086	\$ 0.096	\$ 0.099	\$ 0.094	\$ 0.092	32.8%
Large LGS High Load Factor Winter Peak	\$ 0.043	\$ 0.043	\$ 0.047	\$ 0.051	\$ 0.054	\$ 0.060	\$ 0.062	\$ 0.057	\$ 0.057	30.7%
Large LGS Low Load Factor Flat Usage	\$ 0.065	\$ 0.065	\$ 0.070	\$ 0.077	\$ 0.081	\$ 0.091	\$ 0.094	\$ 0.089	\$ 0.087	33.2%
Large LGS High Load Factor Flat Usage	\$ 0.043	\$ 0.043	\$ 0.047	\$ 0.051	\$ 0.054	\$ 0.060	\$ 0.062	\$ 0.057	\$ 0.057	30.7%
Small SPS Low Load Factor Winter Peak	\$ 0.067	\$ 0.072	\$ 0.079	\$ 0.083	\$ 0.089	\$ 0.093	\$ 0.097	\$ 0.093	\$ 0.083	24.0%
Small SPS High Load Factor Winter Peak	\$ 0.044	\$ 0.047	\$ 0.052	\$ 0.054	\$ 0.058	\$ 0.061	\$ 0.063	\$ 0.058	\$ 0.056	28.4%
Small SPS Low Load Factor Flat Usage	\$ 0.070	\$ 0.075	\$ 0.082	\$ 0.086	\$ 0.093	\$ 0.097	\$ 0.101	\$ 0.097	\$ 0.087	24.3%
Small SPS High Load Factor Flat Usage	\$ 0.044	\$ 0.047	\$ 0.052	\$ 0.054	\$ 0.058	\$ 0.061	\$ 0.063	\$ 0.058	\$ 0.056	28.5%
Large SPS Low Load Factor Winter Peak	\$ 0.065	\$ 0.070	\$ 0.077	\$ 0.081	\$ 0.087	\$ 0.091	\$ 0.094	\$ 0.090	\$ 0.079	20.7%
Large SPS High Load Factor Winter Peak	\$ 0.042	\$ 0.045	\$ 0.049	\$ 0.051	\$ 0.055	\$ 0.058	\$ 0.060	\$ 0.055	\$ 0.053	27.4%
Large SPS Low Load Factor Flat Usage	\$ 0.062	\$ 0.067	\$ 0.073	\$ 0.076	\$ 0.082	\$ 0.086	\$ 0.090	\$ 0.085	\$ 0.075	21.1%
Large SPS High Load Factor Flat Usage	\$ 0.042	\$ 0.045	\$ 0.049	\$ 0.051	\$ 0.055	\$ 0.058	\$ 0.060	\$ 0.055	\$ 0.053	27.4%
Small LPS Low Load Factor Winter Peak	\$ 0.057	\$ 0.062	\$ 0.069	\$ 0.072	\$ 0.077	\$ 0.081	\$ 0.081	\$ 0.081	\$ 0.076	33.8%
Small LPS High Load Factor Winter Peak	\$ 0.022	\$ 0.023	\$ 0.026	\$ 0.028	\$ 0.030	\$ 0.031	\$ 0.031	\$ 0.029	\$ 0.029	34.6%
Small LPS Low Load Factor Flat Usage	\$ 0.059	\$ 0.063	\$ 0.071	\$ 0.075	\$ 0.080	\$ 0.084	\$ 0.084	\$ 0.083	\$ 0.079	33.8%
Small LPS High Load Factor Flat Usage	\$ 0.022	\$ 0.024	\$ 0.027	\$ 0.028	\$ 0.030	\$ 0.031	\$ 0.031	\$ 0.029	\$ 0.030	34.6%
Large LPS Low Load Factor Winter Peak	\$ 0.057	\$ 0.061	\$ 0.069	\$ 0.072	\$ 0.077	\$ 0.081	\$ 0.081	\$ 0.081	\$ 0.076	33.6%
Large LPS High Load Factor Winter Peak	\$ 0.022	\$ 0.023	\$ 0.026	\$ 0.027	\$ 0.029	\$ 0.031	\$ 0.031	\$ 0.028	\$ 0.029	34.5%
Large LPS Low Load Factor Flat Usage	\$ 0.059	\$ 0.063	\$ 0.071	\$ 0.074	\$ 0.079	\$ 0.083	\$ 0.083	\$ 0.083	\$ 0.078	33.6%
Large LPS High Load Factor Flat Usage	\$ 0.022	\$ 0.024	\$ 0.026	\$ 0.028	\$ 0.030	\$ 0.031	\$ 0.031	\$ 0.029	\$ 0.029	34.4%

11

Rebuttal Testimony of
Sarah L.K. Lange

1 Q. What immediate conclusions can one draw from this information?

2 A. Across the LGS, SPS, and LPS classes, customers have experienced increases
3 in the range of 21% -35%, with a simple average increase across all profiles in those classes of
4 30%. Across the Residential and SGS classes, customers have experienced increases in the
5 range of 47%-49%, with a simple average increase across all profiles in those classes of 48%.

6 Q. Is it fair to say that residential customers have experienced a 48% increase while
7 industrial and large commercial customers have experienced a 30% increase?

8 A. No. The Customer Profiles and experienced average \$/kWh provided above
9 are illustrative of the variation that occurs in bills among Ameren Missouri's customers.
10 Given the changes in revenue responsibility and rate design that have occurred since 2007, and
11 given the abilities of non-Residential customers to participate in rate switching, it is misleading
12 at best to assert that any particular customer has experienced any given bill impact without
13 simply comparing that customer's bill from 2007 with the same determinants as billed today
14 (or vice versa).

15 Q. What additional conclusions can one draw from this information?

16 A. Across the LGS, SPS, and LPS classes, lower load factor customers have
17 consistently experienced greater increases than higher load factor customers. For facilitation
18 of comparison, Staff found the simple averages of experienced average \$/kWh for the Customer
19 Profiles by (1) rate schedule, (2) by load factor for the LGS, SPS, and LPS classes combined,
20 (3) by relative size within class for the LGS, SPS, and LPS classes combined, and (4) by relative
21 size across classes, and by load factor across the LGS, SPS, and LPS classes. These results are
22 provided in the table below:

Rebuttal Testimony of
Sarah L.K. Lange

	2007 Average \$/kWh	2017 Average \$/kWh	2021 Average \$/kWh	% Change
Residential Simple Average	\$ 0.0673	\$ 0.1043	\$ 0.0998	48%
SGS Simple Average	\$ 0.0697	\$ 0.1028	\$ 0.0957	37%
LGS Simple Average	\$ 0.0553	\$ 0.0790	\$ 0.0731	32%
SPS Simple Average	\$ 0.0543	\$ 0.0784	\$ 0.0677	25%
LPS Simple Average	\$ 0.0398	\$ 0.0568	\$ 0.0533	34%
Low Load Factor C&I Customer Simple Average	\$ 0.0636	\$ 0.0913	\$ 0.0824	30%
High Load Factor C&I Customer Simple Average	\$ 0.0361	\$ 0.0515	\$ 0.0470	30%
Smaller within Class C&I Customers Simple Average	\$ 0.0504	\$ 0.0723	\$ 0.0657	30%
Larger within Class C&I Customers Simple Average	\$ 0.0492	\$ 0.0705	\$ 0.0638	29%
Smaller C&I Customers Low LF Simple Average	\$ 0.0673	\$ 0.0969	\$ 0.0876	30%
Smaller C&I Customers High LF Simple Average	\$ 0.0437	\$ 0.0624	\$ 0.0568	30%
Larger C&I Customers Low LF Simple Average	\$ 0.0598	\$ 0.0856	\$ 0.0772	29%
Larger C&I Customers High LF Simple Average	\$ 0.0284	\$ 0.0406	\$ 0.0372	31%

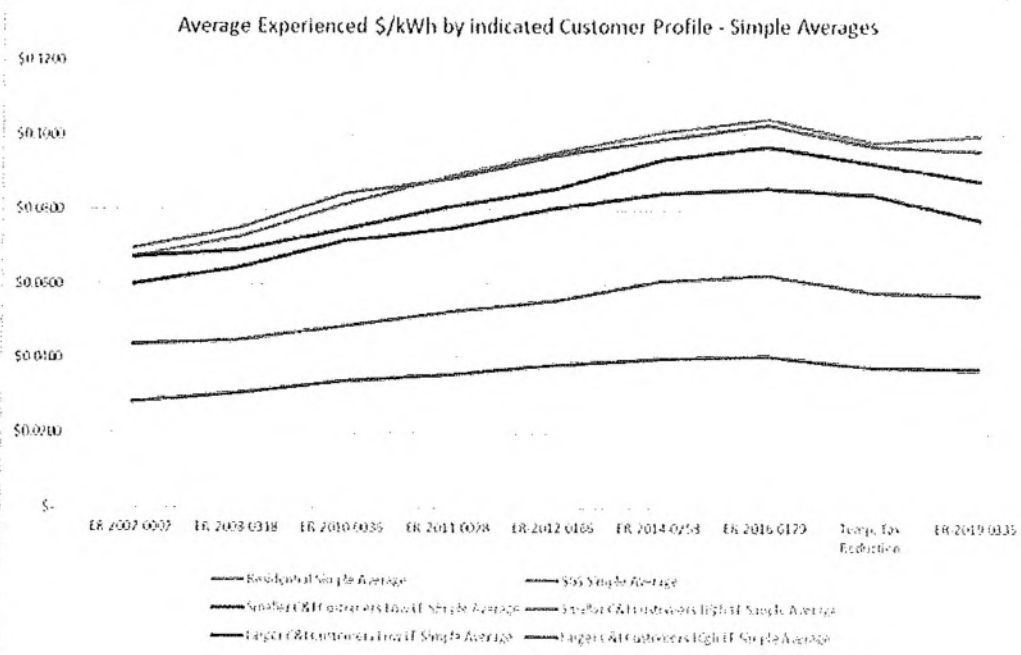
1

2

3

4

The Residential and SGS simple averages are graphed below, with the LGS/SPS/LPS simple averages stratified by overall size and load factor:



5

6

Q. What immediate conclusions can one draw from this information?

Rebuttal Testimony of
Sarah L.K. Lange

1 A. The Larger C&I customers experienced lower average \$/kWh throughout the
2 study period. While the experienced average \$/kWh associated with these customers is
3 increasing (excepting the impacts of the Temporary Tax Reduction) it is at a lower rate than
4 those experienced by the other profiles. Lower load factor C&I customers regardless of size
5 are experiencing increases of magnitudes approaching that experienced by the SGS and
6 Residential simple averages.⁸

7 Q. What changes to the LGS rate elements have occurred since Case No.
8 ER-2007-0002?

9 A. The LGS rate structure with the rate of each element since July 2007 are
10 provided below:

11

Large General Service																
Customer Charge	\$	66.79	\$	67.11	\$	72.26	\$	79.39	\$	83.04	\$	92.35	\$	94.51	94.51	94.51
Low - Income Program Charge							\$	0.50	\$	0.50	\$	0.50	\$	0.56	0.56	0.78
Summer Energy Charge																
First 150 kWh per kW of billing demand	\$	0.0751	\$	0.0751	\$	0.0809	\$	0.0889	\$	0.0930	\$	0.1034	\$	0.1058	0.1058	0.0969
Next 200 kWh per kW of billing demand	\$	0.0565	\$	0.0566	\$	0.0609	\$	0.0669	\$	0.0700	\$	0.0778	\$	0.08	0.0796	0.0729
All Over 350 kWh per kW of billing demand	\$	0.0380	\$	0.0380	\$	0.0410	\$	0.0450	\$	0.0470	\$	0.0523	\$	0.0535	0.0535	0.0491
Summer Demand Charge	\$	3.51	\$	3.51	\$	3.78	\$	4.15	\$	4.34	\$	4.83	\$	5.40	5.4	5.4
Winter Energy Charge																
First 150 kWh per kW of billing demand	\$	0.0473	\$	0.0473	\$	0.0509	\$	0.0560	\$	0.0586	\$	0.0651	\$	0.0665	0.0665	0.0609
Next 200 kWh per kW of billing demand	\$	0.0351	\$	0.0351	\$	0.0378	\$	0.0415	\$	0.0434	\$	0.0483	\$	0.0494	0.0494	0.0452
All Over 350 kWh per kW of billing demand	\$	0.0276	\$	0.0276	\$	0.0297	\$	0.0326	\$	0.0341	\$	0.0380	\$	0.0389	0.0389	0.0356
Seasonal Energy Charge	\$	0.0276	\$	0.0276	\$	0.0297	\$	0.0326	\$	0.0341	\$	0.0380	\$	0.0389	0.0389	0.0356
Winter Demand Charge	\$	1.30	\$	1.30	\$	1.40	\$	1.54	\$	1.61	\$	1.79	\$	2.00	2.00	2.00

12

13 **DISTRIBUTION ALLOCATIONS**

14 Q. Ameren Missouri witness Mr. Hickman states "In this case, as it did in the
15 Company's prior electric general rate case, the Company has used the 'Minimum-Size Method'
16 which is outlined in the National Association of Regulatory Utility Commissioners ("NARUC")

⁸ The Customer Profiles and experienced average \$/kWh provided above are illustrative of the variation that occurs in bills among Ameren Missouri's customers.

1 January 1992 Cost Allocation Manual.”⁹ How does the 1992 NARUC Manual summarize the
2 minimum-size method?

3 A. The 1992 NARUC Manual provides “[c]lassifying distribution plant with the
4 minimum-size method assumes that a minimum size distribution system can be built to serve
5 the minimum loading requirements of the customer. The minimum-size method involves
6 determining the minimum size pole, conductor, cable, transformer, and service that is currently
7 installed by the utility. Normally, the average book cost for each piece of equipment determines
8 the price of all installed units. Once determined for each primary plant account, the minimum
9 size distribution system is classified as customer-related costs. The demand-related costs for
10 each account are the difference between the total investment in the account and the customer-
11 related costs. Comparative studies between the minimum-size and other methods show that it
12 generally produces a larger customer component than the zero-intercept method....”¹⁰

13 Q. How did Ameren Missouri’s minimum system study vary from this description?

14 A. Ameren Missouri’s variations to the NARUC descriptions fall into two broad
15 categories – first, Ameren Missouri based its study on the minimum-size poles, conductors,
16 cables, and devices associated with the portions of its distribution system that operate at primary
17 voltage; second, Ameren Missouri performed its calculations in a sequence that resulted in
18 factoring-up the customer-related costs when finding the difference between the total
19 investment in the account and the customer-related costs.

20 Q. Is it necessarily concerning for a CCoS analyst to vary a method described in a
21 CCoS manual when conducting a given CCoS Study?

⁹ Hickman Direct, page 10.

¹⁰ NARUC Manual at page 91

1 A. No. CCoS Studies are very data intensive and are also subject to system-specific
2 considerations as well as jurisdiction-specific requirements that may apply. However,
3 Mr. Hickman did not identify these variances in his testimony and they became apparent only
4 through review of his workpapers and responses, when provided, to data requests.

5 Ameren Missouri performed its calculations in a sequence that resulted in factoring-up
6 the customer-related costs when finding the difference between the total investment in the
7 account and the customer-related costs.

8 Q. How does the sequence of calculations affect the final allocation of plant
9 and expense?

10 A. In this case, Mr. Hickman's workpapers indicated his calculation of the
11 minimum-size systems-per account using a version of the Continuing Property Record
12 with data as of roughly 1/1/2021. For each account (except Account 366 – Conduit) he found
13 the percentage of minimum-size system based on the total of the CPR costs, excluding
14 non-unitized costs and miscellaneous costs.¹¹ For example, in Account 365 – Overhead
15 Conductors & Devices, Mr. Hickman reviewed plant records and calculated a minimum system
16 cost of \$777,463,914, and the account balance after Mr. Hickman removed non-unitized and
17 miscellaneous costs was \$1,368,414,640. Mr. Hickman used these numbers to create a
18 percentage of 56.8149%, which he decided to use as the “365 Allocator.” However, he applied
19 this percentage to the gross balance of this account in the Ameren Missouri CCoS Study of
20 \$1,752,037,567. 56.8149% of \$1,752,037,567 is not \$777,463,914, it is \$995,332,542.
21 \$995,332,542 is \$217,868,628 more than \$777,463,914.

¹¹ Mr. Hickman's workpapers state that he relied on his calculations for Account 367 – Underground Conductors & Devices, for Account 366 – Conduit.

Rebuttal Testimony of
Sarah L.K. Lange

1 Q. Are the CPR amounts studied by Mr. Hickman reflective of the Gross Plant
2 amounts allocated by Mr. Hickman?

3 A. This varies by account. Overhead conductors and devices, AMI Meters, Meter
4 Installations, Poles Towers & Fixtures, and Lighting are particularly concerning.

5

Account	Description	CPR Total	Ameren Direct	Difference \$	Difference %
364	Poles, Towers, & Fixtures - DP	\$ 1,253,077,844	\$ 1,282,350,821	\$ 29,272,977	2%
365	Overhead Conductors & Devices - DP	\$ 1,420,249,106	\$ 1,752,037,567	\$ 331,788,461	23%
366	Underground Conduit - DP	\$ 591,799,313	\$ 591,799,313	\$ 0	0%
367	Underground Conductors & Devices - DP	\$ 955,320,836	\$ 955,320,836	\$ (0)	0%
368	Line Transformers - DP	\$ 521,169,770	\$ 521,169,770	\$ (0)	0%
369.1	Services - Overhead - DP	\$ 214,886,697	\$ 214,886,697	\$ 0	0%
369.2	Services - Underground - DP	\$ 182,120,703	\$ 182,120,703	\$ 0	0%
370	Meters - DP	\$ 103,632,157	\$ 103,632,157	\$ (0)	0%
370.1	AMI Meters	\$ 49,460,710	\$ 94,675,627	\$ 45,214,917	91%
371	Meter Installations - DP	\$ 135,359,360	\$ 164,613	\$ (135,194,747)	-100%
373	Street Lighting and Signal Systems - DP	\$ 53,927,096	\$ 189,286,456	\$ 135,359,360	251%

6

7 Q. Could it be reasonable to factor up the minimum-size-derived amount under
8 certain circumstances, and what circumstances caused the variation between the amount
9 Ameren Missouri used to find the customer percentage and the account balance reflected in the
10 Ameren Missouri CCoS study?

11 A. Yes. If, for example, Ameren Missouri purchased a system from another utility
12 it may be reasonable to assume the same proportion of minimum system is associated with the
13 additional plant as the studied plant if there was not time or documentation to study the
14 additional plant composition. However, the cause of the growth in Accounts 365 between the
15 time of Mr. Hickman's minimum-size study and his CCoS Study is related to reconductoring
16 of existing line miles and to the installation or upgrade of devices such as switches and
17 lightning arrestors. Additional variation in the balance used to derive the customer percentage
18 and the balance used in the CCoS was introduced by Mr. Hickman's decision to remove the

Rebuttal Testimony of
Sarah L.K. Lange

1 portion of the CPR balance associated with non-unitized plant. Non-unitized plant is included
2 in the CCoS account balances, so removing it from the CPR balance used to find the customer
3 percentage exacerbated the overstatement of customer-related costs in the Ameren Missouri
4 CCoS Study.

5 Q. What is the impact of this order of calculations on the amount of distribution
6 plant allocated on customer counts, and the amount of distribution plant allocated as
7 demand-related?

8 A. On a net-plant basis, approximately \$167,173,289 of Accounts 364-367 that
9 should have been allocated as demand-related were allocated to the classes based on customer
10 counts. This is about 7% of the net plant associated with these accounts.

Account	Calculated Minimum System	Amount Allocated as Customer- Related	Total Account Gross Plant in CCoS Study	Gross Amount Over- Allocated	Net Plant in CCoS Study	Net Plant as % of Gross	Net Amount Over- Allocated
364 - Poles, Tower & Fixtures	\$ 750,137,286	\$ 786,126,910	\$ 1,282,350,821	\$ 35,989,624	\$ 151,910,646	12%	\$ 4,263,425
365 - Overhead Conductors & Devices	\$ 777,463,914	\$ 995,332,542	\$ 1,752,037,567	\$ 217,868,628	\$ 1,193,332,398	68%	\$ 148,392,761
366 - Conduit		\$ 181,268,130	\$ 591,799,313	\$ 5,606,119	\$ 459,220,581	78%	\$ 4,350,200
367 - Underground Conductors & Devices	\$ 277,958,892	\$ 292,614,772	\$ 955,320,836	\$ 14,655,880	\$ 662,713,833	69%	\$ 10,166,903

11
12
13 Ameren Missouri's reliance on the distribution plant allocation to allocate distribution expense
14 also results in an overallocation of distribution expenses to classes with large numbers of
15 customers such as SGS and Residential, and an underallocation of distribution expenses to
16 classes with relatively few customers, such as LPS.

17 Q. How does the RAP Manual address the relationship between the calculated
18 minimum-size cost for a given account and the total account balance?

19 A. On page 146 the RAP Manual states "The minimum system method attempts to
20 calculate the cost (in constant dollars) if the utility's installed units (transformers, poles, feet of
21 conductors, etc.) were each the minimum-sized unit of that type of equipment that would ever
22 be used on the system. The analysis asks: How much would it have cost to install the same

Rebuttal Testimony of
Sarah L.K. Lange

1 number of units (poles, feet of conductors, transformers) but with the size of the units installed
2 limited to the current minimum unit normally installed? This minimum system cost is then
3 designated as customer-related, and the remaining system cost is designated as demand-related.
4 The ratio of the costs of the minimum system to the actual system (in the same year's dollars)
5 produces a percentage of plant that is claimed to be customer-related."

6 This description emphasizes the importance of recognizing that the CPR cost-per-unit
7 of retirement units currently being installed will reflect current pricing, while the other plant in
8 the account will reflect the installed costs of the time it was installed.¹² A simplified example
9 is provided below:

Retirement Unit	Year Installed	Number of Units	Total Cost	Cost per Unit
100' tower	1980	100	\$ 1,000,000	\$ 10,000
100' tower	2020	2	\$ 40,000	\$ 20,000
40' pole	1980	10	\$ 5,000	\$ 500
40' pole	2020	5,000	\$ 5,000,000	\$ 1,000
		5,112	\$ 6,045,000	

11
12 In this example, the system contains 5,112 poles and towers. Most of the 100' towers were
13 installed in 1980, and most of the 40' poles were installed in 2020. The actual system cost is
14 \$6,045,000.

15 The minimum-size system cost would be calculated by finding the average per-unit cost
16 of 40' pole, then multiplying that cost by the 5,112 poles in the system, as provided below:

Retirement Unit	Year Installed	Number of Units	Total Cost	Cost per Unit
100' tower	Average Cost	102	1,040,000	\$ 10,196
40' pole	Average Cost	5,010	5,005,000	\$ 999
		Minimum-Size System \$:	\$ 5,106,898	
		Minimum-Size System %:	84%	

17
18
19 Note that \$5,106,898 is 84% of the actual system cost of \$6,045,000.

¹² Mr. Hickman does include a step recognizing that some per-unit costs are less than the selected minimum-size per unit cost.

Rebuttal Testimony of
Sarah L.K. Lange

1 However, the RAP Manual suggests bringing the dollars associated with each
2 retirement unit to a consistent basis. This could be done various ways, depending on the data
3 available. In this example, the most straightforward approach would be to multiply the
4 number of 100' towers by the 2020 average cost for 100' towers, and to multiply the number
5 of 40' poles by the 2020 average cost for 40' poles, as provided below:

6

Retirement Unit	Year Installed	Number of Units	Total Cost	Cost per Unit
100' tower	Adjusted Cost	102	\$ 2,040,000	\$ 20,000
40' pole	Adjusted Cost	5,010	\$ 5,010,000	\$ 1,000
		Adjusted System Total \$:	\$ 7,050,000	
		Minimum-Size System \$:	\$ 5,112,000	
		Minimum-Size System %:	73%	

7

8 Note that when the Minimum-Size dollars are quantified as a percentage of the Adjusted System
9 Total dollars, the resulting percentage is reduced to 73%, however, this approach may result in
10 a higher or lower percentage relative to the first calculation, depending on the average age of
11 system components and the average age of the minimum-size component.

12 Q. Would the customer-related component found in Ameren Missouri's
13 minimum-size study be expected to be increased or decreased had this analysis been performed?

14 A. Staff reviewed the average age of poles and towers in Account 364. The average
15 age of 40' wood poles was 22 years. The average of age of poles that had a lower per-unit cost
16 than 40' wood poles was 37 years. The average age of poles that had a higher per-unit
17 cost than 40' wood poles was 27 years. In other words, the per-unit cost of the selected
18 minimum-size unit of 40' wood poles were not in consistent dollars with the balance of the
19 account. This indicates that Ameren Missouri's method classified more costs as
20 customer-related and over-allocated distribution costs and expenses to classes with high
21 customer numbers while under-allocating distribution costs and expenses to classes with lower

1 customer numbers than adherence to a minimum-size method conducted pursuant to the
2 RAP Manual.

3 Ameren Missouri based its study on the minimum-size poles, conductors, cables, and
4 devices associated with the portions of its distribution system that operate at primary
5 voltage.

6 Q. Was it reasonable to rely on primary voltage components for a “minimum-size”
7 classification of the distribution system?

8 A. No, 1,294,668 of million Ameren Missouri’s 1,295,396 customers are served at
9 secondary voltage. As discussed in Staff’s CCoS and Rate Design Report, it is unreasonable to
10 use primary-size components as the basis for a minimum-size study without significant
11 adjustments.

12 Q. How does Ameren Missouri’s reliance on primary voltage components for its
13 “minimum-size” study affect the evidentiary reliability of its results?

14 A. Ameren Missouri’s distribution allocation is not based on a reliable analysis
15 under the circumstances. Data availability and limitation are always factors in the design and
16 conduction of CCoS Studies. However, Ameren Missouri is responsible for the maintenance
17 and organization of Ameren Missouri’s plant data, and Ameren Missouri has unique access to
18 the operation and design of the Ameren Missouri distribution system. Ameren Missouri’s
19 CCoS results in an overallocation of distribution plant and expenses to classes with large
20 numbers of customers such as SGS and Residential, and an underallocation of distribution
21 expenses to classes with relatively few customers, such as LPS, such that it cannot provide
22 evidentiary support for increasing the revenue responsibility of classes with large numbers of
23 customers, nor decreasing the revenue responsibility of classes with relatively few customers.

Rebuttal Testimony of
Sarah L.K. Lange

1 Q. Is Mr. Hickman's testimony describing the minimum-size study factually
2 accurate?

3 A. Based on Ameren Missouri's data request responses, portions of Mr. Hickman's
4 testimony are not factually accurate, and mischaracterize the nature of the plant
5 discussed and the degree of input of the Ameren Missouri Distribution Planning Group to the
6 minimum-size study.

7 Q. What is the minimum-size retirement unit actually installed by Ameren Missouri
8 for each of the distribution accounts?

9 A. Ameren Missouri has not provided this information to date. Staff requested
10 this information in its DR 533.1, issued June 22, 2021. Ameren Missouri's July 26, 2021
11 response, ATTACHED, did not answer this question. This response also stated that
12 "Mr. Hickman's informal conversations with the Distribution Planning Group were focused on
13 reviewing the reasonableness of retirement unit selections previously made. Specific
14 alternatives and selection parameters were not specifically a part of these conversations, as
15 those would have been discussed at the time of the original study. The conversations included
16 the purpose of the minimum distribution study, how it is utilized in cost of service, and whether
17 the previously selected minimum size items were reasonable in the context of the study. There
18 are no specific notes, presentations, or documents from these conversations." In contrast,
19 Mr. Hickman's testimony at page 10 provides:

20 Q. How were the customer-related costs of FERC Account
21 364—poles, towers, and fixtures — determined using the
22 minimum-size method?

23 A. First, the average installed book cost of the minimum height pole
24 currently being installed for the Company's distribution system was
25 determined through discussions with Ameren Missouri's Distribution
26 Planning Group. Then, the average book cost was multiplied by the
27 number of poles to find the customer-related cost component. Poles with

Rebuttal Testimony of
Sarah L.K. Lange

1 average book cost less than the minimum height pole are included at their
2 lower cost...."

3 Tom Hickman's testimony at page 11 is:

4 Q. How were the customer-related costs of FERC Account
5 365—overhead conductors and devices — determined?

6 A. The current minimum size conductor being installed was determined
7 through discussions with the Distribution Planning Group. A weighted
8 average cost of conductor was developed by including every foot of
9 conductor with an average book cost greater than or equal to the average
10 book cost of the minimum size conductor at the average book cost of the
11 minimum size conductor....

12 Tom Hickman's testimony at page 12 is

13 Q. How were the customer-related costs of FERC Accounts 366 and
14 367—underground conduits, conductors and devices — determined?

15 A. For Account 367 (underground conductors and devices), the average
16 minimum size underground conductor was determined through
17 discussions with the Distribution Planning Group. A weighted average
18 cost of conductor was developed consistent with the process described
19 for Account 365 above....

20 Tom Hickman's testimony at page 12 is

21 Q. How were the customer-related costs of FERC Account 368 — line
22 transformers — determined?

23 A. The cost of a minimum size transformer currently being installed was
24 determined through discussions with the Distribution Planning Group.
25 The average cost of the minimum size transformer was multiplied by the
26 number of transformers in the plant account to determine the current cost
27 of the minimum-size system....

28 Q. At what voltage do the retirement units selected by Mr. Hickman operate?

29 A. In its response to DR 533.1, Ameren Missouri represented that the
30 following retirement units operate at the voltages indicated, with the predominant voltage of
31 operation specified:

32 364 Poles – POLE,WOOD,40' – 240V, 480V, 4160V, 12000V, 12470V,
33 13200V, 13800, 25000V – Predominantly 12000V

Rebuttal Testimony of
Sarah L.K. Lange

1 365 Overhead Conductor & Device – WIRE,1/0,ALUMINUM - 240V, 480V,
2 4160V, 12000V, 12470V, 13200V, 13800, 25000V, 34500V – Predominantly
3 12000V

4 367 Underground Conductor & Device – CABLE, 5KV,1-2,RUBBER,CONC
5 NEUT –4160V

6 368 Line Transformers – TRANSFORMER,0025KVA,1PH,7200V – 12000V

7 All of these items operate exclusively or predominantly at primary voltage. Further, in its
8 June 15, 2021 response to Staff’s May 18, 2021 Data Request 474, Ameren Missouri stated
9 “For a typical installation of 40’ poles and 1/0 AAAC wire, this conductor could and would be
10 operated at 4.16kV or 12.47kV, based on current Ameren Missouri construction standards.”

11 Q. What rationale does Mr. Hickman provide for his choice to use primary system
12 components as the minimum-size component in his minimum-size system?

13 A. No explanation was provided.

14 Q. How much of each distribution account is sized to operate at secondary voltage?

15 A. Staff does not have access to that information and attempts to obtain that
16 information from Ameren Missouri have largely been unsuccessful. On September 8, 2021,
17 Ameren Missouri provided a supplemental response¹³ to Staff’s DR 104.9, issued July 2, 2021¹⁴
18 indicating that “a very rough guess of miles of overhead secondary would be a range 50%

¹³ “There would not be much mileage of overhead secondary circuit alone. Overhead secondary would most likely be collocated with overhead primary in the areas where primary exists. Secondary would exist in areas that have a higher customer density. Very little overhead secondary would exist in rural areas due to distance between customers. Based this assumption, a very rough guess of miles of overhead secondary would be a range 50% to 60% of the miles of overhead primary. Please note that this is a very subjective estimate, and as we get our secondary into the mapping system over time this information should be updated. The miles of underground secondary should be able to be derived fairly closely from the information on retirement units in the 367 accounts.”

¹⁴ DR 104.9, “Refer to company’s response to DR 104.5. Please confirm whether the company operates any circuits below 2.4 kV. If the company does operate circuits below 2.24 kV please provide a list of such circuits and identify the voltage at which it operates, the length of each circuit underground and length of each circuit overhead. Please identify the number of customers served on each such circuit. Please identify the accounts to which assets associated with these circuits are recorded. Please provide any information available that quantifies the value of assets associated with these circuits.”

Rebuttal Testimony of
Sarah L.K. Lange

1 to 60% of the miles of overhead primary.” This “very rough guess” indicates approximately
2 11,000 miles of overhead secondary system exists. However, on September 13, 2021,
3 Ameren Missouri provided a supplemental response¹⁵ to Staff’s DR 104.9, issued July 2, 2021.
4 This response provided a list of retirement unit names in accounts 365 and 367 which “could
5 be used for Secondary Voltages (600v and below). Please note, a few of these retirement units
6 may have mixed used, but the majority would be used for secondary exclusively.” Using the
7 version of the CPR contained in Mr. Hickman’s workpapers, these retirement units comprise
8 \$10,628,489, (approximately 0.75%) of the account balance of Account 365, Overhead
9 Conductors & Devices. By length, these retirement units comprise about 1.6 million feet of
10 secondary distribution system, or about 315 miles.

11 However, Mr. Hickman’s CCoS is based on the valuations of the secondary
12 system --beyond the level included in the customer-related portion of each account – indicated
13 in the following table:

14

Account	Account % of Dollars Deemed Secondary	Non-Customer % of Account Deemed Secondary	Gross Plant \$ Deemed Secondary
364 - Poles, Tower & Fixtures	9.72%	25.11%	\$ 124,601,778
365 - Overhead Conductors & Devices	1.69%	3.91%	\$ 29,609,435
366 - Conduit	19.37%	27.92%	\$ 114,631,527
15 367 - Underground Conductors & Devices	19.37%	27.92%	\$ 185,045,646

16 Q. What explanation did Mr. Hickman provide for representing that
17 primary-voltage components were the “minimum size” component “currently being installed”
18 while simultaneously classifying at least \$453,888,386 in assets as secondary voltage?

¹⁵ “Please see the attached excel file MPSC 104.9s2 Response.xlsx. Each tab contains the retirement units for the respective major which could be used for Secondary Voltages (600v and below). Please note, a few of these retirement units may have mixed used, but the majority would be used for secondary exclusively.”

Rebuttal Testimony of
Sarah L.K. Lange

1 A. No explanation was provided. The concept of using primary-sized components
2 of the distribution system for a minimum-size study because there is minimal investment in a
3 secondary distribution system is inconsistent with the practice of classifying significant portions
4 of the distribution accounts as secondary. The logical inconsistency is compounded by failing
5 to net the secondary-deemed portion from the customer-related allocation. For example, if the
6 customer-related portion is assumed to replace the entire distribution system as-built with the
7 “minimum-size” component, but the minimum-size component is bigger than the system
8 as-built, then the cost of those components that are smaller than the minimum-size component
9 should be assumed to be subsumed into the minimum-size system.

10 Q. What explanation did Mr. Hickman provide for treating all lightening arrestors
11 and essentially all switches and reclosers as customer-related?

12 A. On page 10 Mr. Hickman states “Also included in the minimum-size
13 distribution system costs are safety/reliability equipment, like protective relays and lightning
14 arrestors as well and other basics like land and fencing — essentials necessary for providing
15 electrical service regardless of customer usage characteristics.” He provides no further
16 explanation, and his explanation does not account for the differences in cost for a device sized
17 to operate at secondary voltage versus a higher voltage.¹⁶ Aside from an adjustment to the cost
18 of 1,131 out of 424,449 devices to adjust their costing from three phase to one phase, no other
19 adjustments were made in the Ameren Missouri minimum-size study to account for costs
20 differences between devices rated for operation at primary or HV voltage versus what those
21 device costs would have been at secondary voltage.

¹⁶ In DR 477 Staff inquired as to the situations in which distribution poles are fenced on Ameren Missouri’s system and Ameren Missouri responded that “there is no typical situation in which a distribution pole would be fenced on the Ameren Missouri system.” This is apparently inconsistent with the inclusion of the fencing in the poles account as customer-related by Mr. Hickman and his reference to this fencing as essential.

1 **SUMMARY AND CONCLUSION REGARDING DISTRIBUTION ALLOCATION**

2 Q. Did Staff's adjustments to Ameren Missouri's distribution account allocators
3 correct for these issues?

4 A. Not fully. Staff did not have access to data in Ameren Missouri's possession,
5 and eventually ran out of time to perform the adjustments necessary to correct for the issues
6 with Ameren Missouri's allocators. In addition to the issues described above, as discussed in
7 the Staff CCOS and Rate Design Report, Ameren Missouri's study reliability is undermined by
8 the following factors:

9 1. Ameren Missouri made no attempt to assign or allocate the costs of
10 customer-specific distribution lines or equipment to customers served by
11 those lines and equipment at primary,

12 2. Solar infrastructure was allocated as though it was a distribution
13 system "device."

14 3. Obvious misrecordings were discussed in the CCoS and Rate
15 Design Report concerning the underground services account and indicate
16 concerns with the thoroughness and accuracy of Ameren Missouri's review
17 of the accounts for allocation.

18 Q. Are the effects of these issues consistent in direction of impact, or offsetting?

19 A. These issues consistently result in overallocation of revenue responsibility to
20 Res and SGS, and under allocation to LPS and to a lesser extent SPS.

21 Q. What is the purpose of classifying the distribution accounts by secondary,
22 primary, and HV voltage?

23 A. This classification process is performed so that customers served at primary and
24 HV do not contribute to the revenue requirement of secondary voltage assets.

1 Q. What is the purpose of classifying the distribution accounts to identify a
2 customer-related portion?

3 A. The purpose of this step is to identify a level of distribution costs, if any,
4 to allocate to the classes on the basis of customer count. The RAP Manual is generally
5 critical of the minimum-size approach and recommends the basic customer method as best
6 practice.¹⁷ Concerning the minimum system approach, the RAP Manual offers the
7 following critique at page 146 et seq:

8 This minimum system analysis does not provide a reliable basis for
9 classifying distribution investment and vastly overstates the portion of
10 distribution that is customer-related. Specifically, it is unrealistic to
11 suppose that the mileage of the shared distribution system and the number
12 of physical units are customer-related and that only the size of the
13 components is demand-related, for at least eight reasons.

14 1. Much of the cost of a distribution system is required to cover an area
15 and is not sensitive to either load or customer number. The distribution
16 system is built to cover an area because the total load that the utility
17 expects to serve will justify the expansion into that area. Serving many
18 customers in one multifamily building is no more expensive than serving
19 one commercial customer of the same size, other than metering. The
20 shared distribution cost of serving a geographical area for a given load is
21 roughly the same whether that load is from concentrated commercial or
22 dispersed residential customers along a circuit of equivalent length and
23 hence does not vary with customer number.¹⁴⁹ Bonbright found that there
24 is “a very weak correlation between the area (or the mileage) of a
25 distribution system and the number of customers served by the system.”
26 He concluded that “the inclusion of the costs of a minimum-sized
27 distribution system among the customer-related costs seems ... clearly
28 indefensible. [Cost analysts are] under impelling pressure to fudge their

¹⁷ Under the basic customer method, only those costs that actually vary with the number of customers are classified as customer-related. The RAP Manual recommends that the analyst divide the vast majority of distribution costs between demand-related and energy-related using an energy weighted method, such as the average-and-peak method under which demand-related distribution costs are allocated using appropriately broad peak measures that capture the hours with high usage for the relevant system elements while appropriately accounting for diversity in customer usage.

1 cost apportionments by using the category of customer costs as a dumping
2 ground” (1961, p. 348).

3 2. The minimum system approach erroneously assumes that the minimum
4 system would consist of the same number of units (e.g., number of poles,
5 feet of conductors) as the actual system. In reality, load levels help
6 determine the number of units as well as their size. Utilities build an
7 additional feeder along the route of an existing feeder (or even on the same
8 poles); loop a second feeder to the end of an existing line to pick up some
9 load from the existing line; build an additional feeder in parallel with an
10 existing feeder to pick up the load of some of its branches; and upgrade
11 feeders from single-phase to three-phase. As secondary load grows, the
12 utility typically will add transformers, splitting smaller customers among
13 the existing and new transformers.¹⁵⁰ Some other feeder construction is
14 designed to improve reliability (e.g., to interconnect feeders with
15 automatic switching to reduce the number of customers affected by
16 outages and outage duration).

17 3. Load can determine the type of equipment installed as well. When load
18 increases, electric distribution systems are often relocated from overhead
19 to underground (which is more expensive) because the weight of lines
20 required to meet load makes overhead service infeasible. Voltages may
21 also be increased to carry more load, requiring early replacement of some
22 equipment with more expensive equipment (e.g., new transformers,
23 increased insulation, and higher poles to accommodate higher voltage or
24 additional circuits). Thus, a portion of the extra costs of moving equipment
25 underground or of newer equipment may be driven in part by load.

26 4. The “minimum system” would still meet a large portion of the average
27 residential customer’s demand requirements. Using a minimum system
28 approach requires reducing the demand measure for each class or
29 otherwise crediting the classes with many customers for the load-carrying
30 capability of the minimum system (Sterzinger, 1981, pp. 30-32).

31 5. Minimum system analyses tend to use the current minimum-sized unit
32 typically installed, not the minimum size ever installed or available. The
33 current minimum unit is sized to carry expected demand for a large
34 percentage of customers or situations. As demand has risen over time, so
35 has the minimum size of equipment installed. In fact, utilities usually stop
36 stocking some less expensive small equipment because rising demand
37 results in very rare use of the small equipment and the cost of maintaining
38 stock is no longer warranted.¹⁵¹ However, the transformer industry could

1 produce truly minimum-sized utility transformers, the size of those used
2 for cellular telephone chargers, if there were a demand for these.

3 6. Adding customers without adding peak demand or serving new areas
4 does not require any additional poles or conductors. For example, dividing
5 an existing home into two dwelling units increases the customer count but
6 likely adds nothing in utility investment other than a second meter.
7 Converting an office building from one large tenant to a dozen small
8 offices similarly increases customer number without increasing shared
9 distribution costs. And the shared distribution investment on a block with
10 four large customers is essentially the same as for a block with 20 small
11 customers with the same load characteristics. If an additional service is
12 added into an existing street with electrical service, there is usually no
13 need to add poles, and it would not be reasonable to assume any pole
14 savings if the number of customers had been half the actual number.

15 7. Most utilities limit the investment they will make for low projected sales
16 levels, as we also discuss in Section 15.2, where we address the
17 relationship between the utility line extension policy and the utility cost
18 allocation methodology. The prospect of adding revenues from a few
19 commercial customers may induce the utility to spend much more on
20 extending the distribution system than it would invest for dozens of
21 residential customers.

22 8. Not all of the distribution system is embedded in rates, since some
23 customers pay for the extension of the system with contributions in aid of
24 construction, as discussed in Section 15.2. Factoring in the entire length
25 of the system, including the part paid for with these contributions,
26 overstates the customer component of ratepayer-funded lines. Thus, the
27 frequent assumption that the number of feet of conductors and the number
28 of secondary service lines is related to customer number is unrealistic. A
29 piece of equipment (e.g., conductor, pole, service drop or meter) should
30 be considered customer-related only if the removal of one customer
31 eliminates the need for the unit. The number of meters and, in most cases,
32 service drops is customer-related, while feet of conductors and number of
33 poles are almost entirely load-related. Reducing the number of customers,
34 without reducing area load, will only rarely affect the length of lines or the
35 number of poles or transformers. For example, removing one customer
36 will avoid overhead distribution equipment only under several unusual
37 circumstances.¹⁵² These circumstances represent a very small part of the
38 shared distribution cost for the typical urban or suburban utility,

Rebuttal Testimony of
Sarah L.K. Lange

1 particularly since many of the most remote customers for these utilities
2 might be charged a contribution in aid of construction. These
3 circumstances may be more prevalent for rural utilities, principally
4 cooperatives.

5 ¹⁴⁹ As noted above, for some rural utilities, particularly cooperatives that
6 extend distribution without requiring that the extension be profitable, a
7 portion of the distribution system may effectively be customer-specific.

8 ¹⁵⁰ Adding transformers also reduces the length of the secondary lines
9 from the transformers to the customers, reducing losses, voltage drop or
10 the required gauge of the secondary lines.

11 ¹⁵¹ For example, in many cases, utilities that make an allocation based on
12 a minimum system use 10-kVA transformers, even though they installed
13 3-kVA or 5-kVA transformers in the past some utilities also have used
14 conductor sizes and costs significantly higher than the actual minimum
15 conductor size and cost on their systems.

16 ¹⁵² These circumstances are: (1) if the customer would have been the
17 farthest one from the transformer along a span of secondary conductor that
18 is not a service drop; (2) if the customer is the only one served off the last
19 pole at the end of a radial primary feeder, a pole and a span of secondary,
20 or span of primary and a transformer; and (3) if several poles are required
21 solely for that customer.

22 Q. As it relates to the distribution plant and expense accounts, what considerations
23 should the Commission keep in mind when interpreting the Ameren Missouri CCoS Study
24 results?

25 A. Staff has several concerns with the study and notes that generally the
26 deficiencies of the study relate to Ameren Missouri's inability or unwillingness to provide
27 (1) the data necessary to differentiate the costs of primary assets, HV assets, and secondary
28 assets to insulate customers served at HV and primary voltages from the costs of the secondary
29 system, (2) the data necessary to perform a minimum-size study,¹⁸ and (3) the customer-specific

¹⁸ Under a best practices approach as described in the RAP manual, these first two sets of data may be unnecessary.

Rebuttal Testimony of
Sarah L.K. Lange

1 assets that are recorded in accounts other than the meters accounts and services accounts. In
2 general, these deficiencies shift revenue responsibility to the residential and SGS classes, and
3 away from the LPS, SPS, and to a lesser extent, the LGS classes. If Ameren Missouri continues
4 to allocate assumed secondary costs away from higher-voltage customers and continues to rely
5 on an approach other than the basic customer approach, Staff notes that identification of the
6 assets or the book value of the assets of (1) the secondary-voltage components of each account,
7 (2) the primary-voltage components of each account, and (3) the HV components of each
8 account is essential. Regardless of whether the RAP best practice is implemented, identification
9 of the customer-specific assets that are recorded in accounts other than the meters accounts and
10 services accounts remains necessary.

11 Q. Does this conclude your rebuttal testimony?

12 A. Yes.