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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2021-0240

REBUTTAL TESTIMONY

OF

MARK C. BIRK

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

**St. Louis, Missouri
October, 2021**

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REBUTTAL TESTIMONY

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1

I. INTRODUCTION

2

Q. Please state your name and business address.

3

A. My name is Mark C. Birk. My business address is One Ameren Plaza, 1901
4 Chouteau Ave., St. Louis, Missouri.

5

Q. By whom are you employed and what is your position?

6

A. I am employed by Union Electric Company d/b/a Ameren Missouri
7 ("Company" or "Ameren Missouri") as Senior Vice President, Customer and Power
8 Operations.

9

**Q. Please describe your educational background and employment
10 experience.**

11

A. I received my Bachelor of Science degree in Electrical Engineering from
12 the University of Missouri-Rolla in 1986 and my Master of Science in Electrical
13 Engineering from the same institution in 1991. In 2009, I also received a Master of
14 Business Administration from Washington University in St. Louis. I am a licensed
15 professional engineer in the State of Missouri. I began my employment with Union Electric
16 Company in 1986 as an assistant engineer in the nuclear function. In 1989, I transferred to
17 Union Electric's Meramec Power Plant as an electrical engineer. In 1996, I transferred to
18 the Energy Supply Operations Group and became a Power Supply Supervisor. I became
19 Manager of Energy Supply Operations in the spring of 2000. I became General Manager

1 of Energy Delivery Technical Services in the fall of 2001 and Vice President of that
2 department in 2002. I became Vice President of Ameren Energy, Inc., Ameren
3 Corporation's short-term trading affiliate, in the fall of 2003 and assumed the position with
4 Ameren Missouri as Vice President of Power Operations in September of 2004. In 2012,
5 I was promoted to Senior Vice President of Corporate Planning and Business Risk
6 Management, and in 2015, I became Senior Vice President of Corporate Safety, Planning,
7 and Operations Oversight. I assumed my current position in 2017.

8 **Q. Please summarize your duties and responsibilities as Senior Vice**
9 **President, Customer and Power Operations for Ameren Missouri.**

10 A. In this position, I am responsible for Generation and Trading Operations,
11 Energy Delivery Electric and Gas Operations, Planning and Engineering Design, along
12 with Customer Experience and call center operations for Ameren Missouri.

13 **Q. To what testimony or issues are you responding?**

14 A. My testimony responds to concerns or issues raised by Office of the Public
15 Counsel witness Dr. Geoff Marke's testimony in a section of his direct testimony he labeled
16 "Plant in Service Accounting ('PISA')".

17 **Q. More specifically, what do you understand Dr. Marke's concerns or issues**
18 **to be?**

19 A. As I read Dr. Marke's testimony, he is concerned about what he characterizes as
20 a lack of "transparency" or "accountability" about the investments in the grid that we are making
21 as part of the Smart Energy Plan ("SEP") we undertook at the beginning of 2019.

1 **II THE COMPANY'S ENERGY DELIVERY INVESTMENTS**

2 **Q. Do you agree with Dr. Marke's concerns?**

3 A. No, I do not, but before getting into the details of why Dr. Marke's viewpoint
4 on these issues is incorrect, I would like to first make sure the Commission has a complete
5 understanding of why the Company has substantially increased its energy delivery system
6 investments since the passage of S.B. 564.¹

7 **Q. Please elaborate.**

8 A. To understand why we are making these investments to better support
9 customers now, one needs to understand some history about our energy delivery system and our
10 investments in it in the past.

11 For many years prior to the passage of S.B. 564, which as I discuss further below
12 enabled us to implement the SEP, Ameren Missouri operated and maintained its energy delivery
13 system – and replaced certain components of it after they had degraded or even failed – in a
14 much more reactive manner which often led to longer customer outages and lower resiliency
15 and reliability. We did so at a level of capital investment that while sufficient at the time to
16 maintain a reasonably reliable system, was not sustainable over the long term. While we were
17 able to deliver safe and adequate service, our investments in the system and our approach to
18 operations at that time meant the system had less ability to withstand severe weather, continued
19 to age further past the design life of many of its components, and overall, the system was not
20 capable of serving our customers in a manner that they expect today, much less in the future.
21 While we did the best we could to meet customer expectations, there were significant limits to

¹ Enacting, among other things, RSMo Section 393.1400, which is commonly referred to as the “PISA” statute.

1 how much capital we could reasonably invest in the system given the disincentive to invest in
2 electric utility infrastructure that existed prior to the passage of S.B. 564.

3 **Q. How did S.B. 564 enable Ameren Missouri to increase its investments in**
4 **ways that would address the kind of energy delivery system concerns you just mentioned?**

5 A. While we still have limits on what we can invest, both to balance system needs
6 with customer affordability and to avoid the negative impacts of remaining regulatory lag on
7 the Company, S.B. 564 created a tool designed by the legislature to remove the disincentive to
8 investment that existed under traditional regulatory treatment of investments, that tool being
9 plant-in-service accounting, or "PISA". As the Commission knows, the PISA mechanism
10 allows utilities like us to defer to a regulatory asset the return and depreciation expense on 85%
11 of prudent investments in qualifying electric plant (most energy delivery system investments
12 qualify) that we would otherwise lose forever between rate cases, and then recover the deferred
13 sums through base rates over 20 years. Regulatory lag exists on the remaining 15% of our capital
14 investment. And there is even some lag on the 85%, due to the impact of certain accounting
15 rules around what return can be recorded to earnings at the time of the deferral, although that
16 portion of the return is eventually recovered.² The legislature's purpose was to substantially
17 remove the disincentive to invest so that utilities like us could provide better, more reliable and
18 resilient service by investing more heavily in our systems for the long-term benefit of our
19 customers and the state – but the legislation purposefully retained some of the regulatory lag
20 inherent in traditional ratemaking to maintain the incentive to make those investments
21 prudently. These investments also provide the ancillary benefit of creating jobs, economic
22 activity, and a greater tax base in the state.

² PISA applies to investments other than energy delivery investments but my focus here is on the energy delivery system.

1 By mitigating the regulatory lag and mitigating the disincentive to invest, S.B. 564
2 enables us to deploy more capital into our aged energy delivery system for the long-term benefit
3 of our customers, and that is what we are doing.

4 **Q. You earlier talked about what it appears could be characterized as some**
5 **shortcomings in the existing system given the capital constraints in the past that you**
6 **discussed. Why do those shortcomings exist?**

7 A. To put this issue in context, please note that Ameren Missouri has more than 30,000
8 miles of distribution circuits spread across 62 of Missouri's 114 counties (including the City of
9 St. Louis). Much of it was built-out in the 1950s and 1960s and even though replacements and
10 upgrades have occurred, especially after storms damaged or destroyed the original equipment,
11 our system is very much showing its age. For example, when SEP investments began in 2019,
12 over 250 of our distribution substations (we have over 500 such substations) contain critical
13 operating components, either a transformer or circuit breaker that was installed more than 50
14 years ago. These substations with aged critical components serve over 500,000 of our 1.2
15 million customers, meaning many of our critical substation components are well beyond their
16 design life, which increases safety and reliability concerns; they simply need to be replaced. If
17 we had not begun upgrading our substation fleet in 2019, by 2023 over 50 additional distribution
18 substations serving an additional 200,000 customers would have a critical component reach 50
19 years of age. This means, in total, that 700,000 of our 1.2 million customers would have been
20 served by a substation with critical components that are at least 50 years old. Upgrading and
21 modernizing this critical infrastructure will improve safety for Ameren Missouri coworkers
22 and customers while also improving reliability and resilience to meet the needs and
23 expectations of our customers over the long term.

1 These issues go beyond our substations. Many of the system's 34 kilovolt ("kV") and
2 69 kV sub-transmission circuits were installed in that 1950's and 1960's timeframe I
3 mentioned earlier, utilizing construction approaches and technology from that time period.
4 Those assets are both past their design lives and inferior from a safety, operating, and
5 performance perspective when compared to today's construction standards and technology
6 (composite poles, standoff insulators, wind resistant conductors, OPGW shield wire, etc.).
7 Other parts of our system are even older. We have nearly 3,700 miles of cable across the
8 system that is also past its design life with some vintages dating as far back as the 1920's,
9 much of which is at least 40 years old. Not only is it old, but much of it was buried directly
10 in the ground without protective conduit and the impact from the direct contact with the
11 soil has degraded the cable more quickly than originally expected, resulting in higher risk
12 of failure compared with modern cable properly installed in protective conduit. In fact, our
13 customers experience a failure rate of this older cable that is double the failure rate of newer
14 cable installed after 1984.

15 To put these needs into perspective, we estimate that through 2030 it will take
16 approximately \$11 billion (in 2021 dollars) of investments in our distribution system to
17 address all of the aged infrastructure, complete the effort of hardening those portions of the
18 sub-transmission system that most need it against severe weather, deploying Distribution
19 Automation ("DA") across the system and the associated circuit upgrades needed to take
20 advantage of DA, and address capacity constraints across the system that limit operating
21 flexibility and delay restoration time in contingent scenarios, among other needs.

22 Ameren Missouri is not alone in facing these issues and we are not the only ones who
23 recognize the problem. According to the American Society of Civil Engineers, "most of the

1 nation's transmission and distribution lines were constructed in the 1950s and 1960s, with
2 a 50-year life expectancy, meaning they have reached or surpassed their intended
3 lifespan.”³ That assessment is very much true of our system, and it is a key reason why we
4 are prioritizing distribution investments.

5 In addition to just the basic need to replace aging infrastructure as a means to de-risk the
6 system against what would inevitably be more frequent and lengthy outages and higher costs to
7 replace equipment reactively instead of doing so in an orderly and planned fashion, we also need
8 to be ready to meet the needs of the grid in the future, including issues created by things like the
9 greater proliferation of distributed energy resources ("DER") and the need for two-way power
10 flows. We will also need many more monitoring and sensing devices to be ready to
11 accommodate changes in policy, such as we are seeing in the FERC's recent issuance of Order
12 2222.

13 **Q. So how are you attacking the problem?**

14 A. The first thing we are doing is we are making what I would call "foundational"
15 investments to upgrade and modernize the grid using construction approaches and
16 components manufactured and installed to today's standards. By "foundational", I mean
17 those assets that are required for the basic movement of electrons from a generation
18 location to the customer premise including poles, wires, transformers, cables, substation
19 replacement program, etc. Much of this infrastructure both supports and benefits from its
20 part of the integrated grid. Ameren Missouri relies on field personnel and Ameren Missouri
21 subject matter experts in areas of distribution planning and operations who have detailed
22 knowledge in the daily operation of the grid to make the best judgment, based on their

³ American Society of Civil Engineers, "Failure to Act: Electric Infrastructure Investment Gaps in a Rapidly Changing Environment," 2020.

1 expertise, in identifying investments to upgrade and modernize the distribution system.
2 These experts who identify investments for the distribution system consider a number of
3 factors when proposing a project, such as age of assets, safety, historical reliability
4 measures, worst performing circuits, number of customers impacted, operating experience
5 in the field, operating performance during storms, asset loading, expected future load
6 growth, voltage conditions, and many others. Specifically, on an annual basis a team of
7 distribution planning engineers examine the recent and five-year projected peak loading of
8 all circuits and substations on the system for any limitations to serve the peak load.
9 Additionally, the distribution planning engineers evaluate system losses and system
10 voltage levels in their annual evaluation of the overall system.

11 **Q. Is it appropriate to require that benefits that can be quantified reach a**
12 **certain threshold for projects to be executed?**

13 A. No, it is often not possible to accurately quantify discrete financial benefits,
14 and even if estimations can be made for some projects, the discrete quantifiable benefits of
15 an individual project may or may not meet a 1.0 threshold.⁴ However, when looking at the
16 grid as a whole and taking all of the factors listed above into account, the need for a project
17 becomes clear in order to maintain or improve continued safe and reliable service for our
18 customers. To justify every project on an individual basis via just determining quantifiable
19 benefits, Ameren Missouri would likely have to wait until customers have experienced a
20 certain number and length of outages and also increased maintenance on the assets before
21 a given project could "pass" a prescriptive cost/benefit test, which would almost always
22 rely on a set of assumptions that may or may not be very accurate. To put it another way,

⁴ A "1.0 threshold," meaning quantified benefits exceed quantified costs.

1 essentially what we are in the midst of doing is replacing the old, outdated past-its-design-
2 life system with a better and more modern robust system to lay the foundation for a more
3 reliable grid over time and for the current and future electrical needs of our customers that
4 will better prevent or limit interruptions and longer outages.

5 **Q. What structure exists around this effort?**

6 A. To execute on these investments, we developed a structure to categorize and
7 then prioritize projects based on the varied need being addressed by the required
8 improvement, creating six categories of investments, as follows:⁵

9 ***Grid Resiliency*** – This category primarily supports maintaining and
10 improving customer reliability. This is achieved by building in the needed
11 capability to support switching activities that allow Ameren Missouri to
12 restore a larger number of customers more quickly through alternate grid
13 configurations during various outage scenarios. Some resiliency projects
14 might also include work that hardens the system or adds smart grid
15 technology.

16 ***Smart Grid*** – Ameren Missouri's grid currently relies on manual
17 intervention to determine the cause and location of outages and then
18 subsequent switching to repair and restore the grid. To reduce the need for
19 manual intervention and ultimately to improve reliability (fewer outages or
20 shorter outages when they happen), we are investing in technologies which
21 will enable new digital grid management capabilities to support more

⁵ There is some overlap between the categories, but projects are categorized into a given category based upon the predominant purpose of the project, as identified by planners and field personnel when the projects are developed.

1 efficient switching of the flow of electricity and quicker outage restoration.
2 Working together, these smart switching devices, grid-edge sensing
3 devices, and communication technologies enable new capabilities such as
4 real-time grid visibility, remote control options, enhanced data collection,
5 and self-healing capabilities. Projects in this category are primarily
6 identified based on reliability history and operating considerations.

7 ***Substation CBM*** –Substations play a critical role in delivering customers
8 safe, reliable, and affordable energy as the midpoint between high voltage,
9 long distance transmission lines and the distribution lines that deliver
10 energy to customers' homes and businesses. The substation condition-based
11 modernization ("CBM") strategy is a critical element of a comprehensive
12 substation asset management plan. Projects in this category are primarily
13 identified based on addressing end-of-life assets that contribute to reliability
14 and maintenance related issues, i.e., we are attacking the high age of our
15 substations as discussed earlier. We also take into account the operational
16 and maintenance historical performance when making replacement or
17 upgrade decisions on some of these substation assets.

18 ***System Hardening*** –The System Hardening category includes both
19 replacing the aged assets I spoke of earlier and the upgrading of assets
20 because construction practices and equipment standards have improved
21 from when the asset was originally installed 40 plus years ago.

22 ***Underground Cable*** –This category targets aged underground direct buried
23 cable infrastructure outside of downtown St. Louis and Clayton – the 3,700

1 miles of cable I mentioned earlier - to address the aged condition of the
2 cable and reliability concerns that have arisen or that will continue to arise
3 from defects in the cable, as well as the occasional safety issues when the
4 cable fails.

5 ***Underground Revitalization*** – This category targets aged underground
6 infrastructure in downtown St. Louis and Clayton with a history of failures.
7 Most of this system is over 50 years old. Given the criticality and size of
8 many downtown customers, a comprehensive multiyear plan was
9 established and is being executed to replace all of the cables running under
10 the streets in downtown St. Louis. The plan includes redesigning the layout
11 of cables across downtown St. Louis to increase the route diversity and
12 mitigate the risks of multiple outages from many cables following the same
13 pathway and being impacted when a single cable in the path fails. We are
14 also installing modern cable, manhole and conduit technology to replace the
15 aged infrastructure in downtown St. Louis, and using remote controlled
16 switching devices to speed restoration activities in the event of future
17 planned or unplanned outages. In addition to installing an improved system
18 from an operational and outage mitigation standpoint, the upgrade reduces
19 existing safety risks arising from deteriorated manholes and cable and splice
20 conditions.

21 **Q. The above discussion suggests that there have been and are more**
22 **system needs than there is or has been capital to address those needs. Is that a fair**
23 **interpretation?**

1 A. Yes, it is. The work we are doing is not "gold plating" or " nice to have"
2 work but rather it is work that our system planners and those that operate and maintain the
3 system on a day-to-day basis have determined should be done to have a reliable system
4 that will meet the needs and ever-increasing expectations of our customers. While there are
5 assets on the system that have operated beyond their intended design life, like any other
6 mechanical device, they cannot be expected to last forever, and the risk of malfunction and
7 mis-operation increases the longer they remain on the grid.

8 **Q. Which brings us back to what appears to be Dr. Marke's main**
9 **contention, that is, that he desires to see some kind of quantifiable metrics relating to**
10 **the energy delivery system investments the Company is making. How do you**
11 **respond?**

12 A. Dr. Marke's primary focus is on having a "cost/benefit analysis" underlying
13 our energy delivery projects. By that I take it he means we should estimate the cost of a
14 project, then make assumptions about benefits that (based on those assumptions) could be
15 quantified, and then make a "go or no go" decision only if the calculated cost/benefit ratio
16 is at least 1.0. Such an approach is inappropriate (and we are not taking it) for the energy
17 delivery system investments we are making.

18 **Q. Why is such an approach inappropriate?**

19 A. Because one cannot make the decisions we need to make to address the
20 needs of our aging system, expectations of our customers, or to address acute problems on
21 the system via a quantification exercise. Instead, we have system needs and problems that
22 need to be addressed and solved. To do so, we must prioritize the most pressing needs and
23 problems, as identified by those with responsibility for operating and maintaining the

1 system, and then choose the best solution to solve the problem, regardless of whether some
2 kind of "pass-fail" quantification test would theoretically be met, so long as we can do so
3 consistent with the capital we have available each year, subject to practical considerations
4 and constraints such as limited equipment and or limits on the availability of labor.

5 **Q. Please explain how decisions on the investments do need to be, and are**
6 **being, made.**

7 A. Aside from the fact that we know that there are large areas and components
8 of our energy delivery system that are at, near, or past their design lives, and that we need
9 to modernize and upgrade them or risk a significant degradation in our system reliability
10 (and to arrest what would otherwise be the continued aging of the system), we also identify
11 projects based on specific needs identified within each district by our engineers and field
12 personnel, and based upon the judgment of subject matter experts in areas of distribution
13 planning and operations who have detailed knowledge in the daily operation and
14 maintenance of the grid. Collectively, these coworkers identify potential projects for the
15 distribution system based upon a number of considerations (and this varies depending on
16 the need/problem being addressed/solved), including, but not limited to, age of assets,
17 safety, historical reliability measures, worst performing circuits, number of customers
18 impacted, operating experience in the field, operating performance during storms, asset
19 loading, expected future load growth, and many others. While the subject matter experts
20 and the owners of the categories I listed earlier in my testimony do consider costs and
21 benefits, this is not the overriding factor by any means.

22 **Q. Are there other drivers of the need for greater investment in the system**
23 **that come to mind?**

1 A. One obvious one is the increased severity and frequency of major weather
2 events which can have a profound effect on reliability year-to-year. A consensus certainly
3 appears to exist that we have seen and will be seeing storms with greater frequency and
4 intensity. Even a system that may have performed reasonably well during storms
5 historically – especially before it became aged – will face more performance challenges in
6 the harsher environment we are seeing, especially when coupled with customers' ever-
7 increasing expectations. However, as I described previously, we are upgrading the system
8 to better withstand the impact of these weather events.

9 **Q. Do you have a specific instance where these upgrades have benefited**
10 **customers after a storm?**

11 A. Yes, a very recent one. On August 12, 2021, a very severe storm rolled over a
12 significant part of Ameren Missouri's service territory interrupting service for an extended
13 period to nearly 94,000 customers. As we recovered from the storm it was clear that circuits
14 that had been upgraded with automated switching capabilities along with the necessary
15 line, tie, and substation upgrades prevented an extended outage for an additional 8,500
16 customers. This means that circuit and substation upgrades of the type we are implementing
17 resulted in an 8% reduction in the number of customers who experienced an extended
18 outage from this one storm. Moreover, the totality of our upgrades discussed in this
19 testimony allowed us to restore 56% of the customers who did experience an extended
20 outage within 12 hours and 80% of those customers within 24 hours, which in my
21 experience is significantly faster than we would have been able to achieve had a similar
22 storm occurred ten years ago. For example, on May 31, 2013 at a time when there was little
23 to no automated switching capability on the system, a storm interrupted service for 94,000

1 customers and only 15% of them were restored within 12 hours, and just 36% within 24
2 hours.

3 **Q. Dr. Marke uses the term "performance metrics", suggesting those have**
4 **a role in deciding on system investments. Please comment.**

5 A. While Dr. Marke may make it sound simple, that is, to set some quantifiable
6 target and make investment decisions based on that target, as I discussed earlier ensuring
7 that we have a robust distribution system that will meet the long-term needs of our
8 customers is not that simple. We do of course track certain reliability metrics and we have
9 established short- to intermediate-term targets for them. Specifically, performance targets
10 for SAIFI and SAIDI⁶ are set each year. Continuous improvement is the primary driver
11 behind both the one- and five-year targets. An example was when setting the 2020-2024
12 SAIFI targets, a five-year average was used from 2014-2018 that excluded the anomaly of
13 2019 and was set at .74 with a target to achieve a .01 decrease in each of the following
14 years. The one- and five-year targets are updated annually with previous year's results taken
15 into consideration. In 2021 the following targets were set:

16 SAIFI - .73, each customer would have on average less than one outage a year.

17 SAIDI – 86, each customer would experience an outage lasting no more than 86
18 minutes on average.

19

20 In addition to the 2021 targets that are described above, five-year targets are also
21 established for these reliability metrics. As shown below, a continuous improvement is
22 applied to the annual targets each year through 2025. These metrics are calculated using

⁶ System Average Interruption Frequency Index and System Average Interruption Duration Index, respectively.

1 industry standard Institute of Electrical and Electronics Engineers ("IEEE") methodologies
2 that exclude major event days as determined by historical reliability data.

Measurement	2021	2022	2023	2024	2025
SAIDI	86.1	85.0	83.8	82.6	81.4
SAIFI	.73	.72	.71	.70	.69

3

4 **Q. Dr. Marke throws out a possible metric where one would compare the**
5 **distribution rate base per customer nationally to energy sales and system peaks, and**
6 **then cross-reference those numbers to metrics like SAIDI and SAIFI. What are your**
7 **views about such a comparison?**

8 A. There are several reasons why such comparisons are not meaningful and
9 end up amounting to a numbers-crunching exercise that does not tell us much of anything
10 useful about how we should maintain, replace, and upgrade our distribution system. While
11 it is true as I discussed earlier that there is a general consensus that distribution systems
12 across the country are aged and a lot of the assets are in need of replacement, the situation
13 on the ground for every utility is drastically different. This means comparing metrics from
14 one utility to the next isn't going to produce valid comparisons. Utilities along the coasts
15 that have experienced repeated (and ever-increasing and extensive) hurricanes and tropical
16 storms have likely "refreshed" much larger parts of their distribution systems than we have
17 and may have lower ongoing needs now than we do. Utilities in areas with much lower tree
18 density will also perform much differently from an outage perspective during storm events.
19 Investment levels are also driven by terrain, density of customers, how far-reaching a
20 service territory is, population trends, labor rates in given areas, and many other factors.
21 Investment needs are also not necessarily correlated to energy sales or system peaks. A
22 utility could have flat sales or a flat or even declining peak but if its system needs

1 significant replacement and upgrade, it still should be completing that work to maintain or
2 improve reliability and functionality for the load that it's required to serve on its system.
3 Also, reliability metrics are lagging indicators that only indicate a need to invest after
4 customers have experienced outages.

5 **Q. Dr. Marke expresses worry about "gold-plating" of the distribution**
6 **system. How do you respond?**

7 A. Replacing an aging system, modernizing it so that it can serve customers
8 for decades into the future, and thereby laying the foundation for a more reliable system
9 that can accommodate DERs and other growing needs, including increasing customer
10 expectations over time, is not "gold-plating," as I addressed in detail above. One only has
11 to look at our system to realize we are not "gold plating" anything but making decisions to
12 provide the best service to customers while always balancing the need for customer
13 affordability.

14 **Q. Putting aside some of the specifics of Dr. Marke's testimony on this**
15 **topic, he seems to take issue with the information the Company has provided about**
16 **its distribution system (and its overall SEP investments) in the docket the Commission**
17 **created when the Company elected to utilize PISA. Please comment.**

18 A. S.B. 564 requires that we submit detailed information to the Commission—
19 at the project level for the prompt year - and at an aggregate level for the succeeding four
20 years. We have done this each and every year – in 2019, 2020, and 2021. As an example,
21 the detailed listing submitted to the Commission in File No. EO-2019-0044 and available
22 to all stakeholders for 2021 is attached to my testimony as Schedule MCB-R1. The statute
23 also requires that we hold a stakeholder meeting about this information each year. We have

1 also done this each year along with providing a separate update to the Commission at its
2 Agenda. In summary, we have done exactly what the General Assembly required and aside
3 from Dr. Marke's general complaints in a couple of questions and answers in our last rate
4 review (cut and pasted into his testimony in this case) no party – not the Staff or anyone
5 else – has ever claimed that anything more is needed. In fact, Dr. Marke and OPC have not
6 taken the opportunity given them to ask detailed questions about the investments Dr. Marke
7 is now questioning during the stakeholder meeting or in the two rate reviews that have
8 occurred since we elected to utilize PISA. I should note that Staff opined that our process
9 for identifying the need for projects and how we evaluate them appeared to Staff to be
10 reasonable.

11 **Q. I take it you disagree with Dr. Marke's "encouragement" appearing at**
12 **page 15, ll. 8-9 of his direct testimony?**

13 A. Yes, I do for the reasons discussed above. These quantifications and metrics
14 that Dr. Marke seems to think are the only means of deciding upon investments in our
15 distribution system largely do not make sense for those investments, as I have testified.
16 There were not "omissions" in our filing in this case. We are making investments in the
17 system as we have always done based upon the experience, knowledge and feedback of
18 those who operate and maintain the system, but at a higher investment level than in the past
19 because we can do so as a result of the passage of S.B. 564, just as the legislature expected
20 and intended when it passed the statute. We are also in full compliance with what the
21 legislature said was an appropriate level of reporting and data submission.

22 **Q. Is there a role for certain metrics in assessing ongoing system needs and**
23 **prioritization of investments?**

1 A. I believe there is, including continuing to assess how we are doing on the
2 reliability metrics I discussed earlier, continuing to evaluate whether we should target even
3 greater improvements in those metrics, and working to assess the impacts of investments
4 that we have made in the past two or three years – and that we will continue to make – on
5 system reliability and performance. However, for several reasons it takes a significant
6 amount of time to see the effects of investments in the metrics. For example, not all circuits
7 are impacted by a given storm, or impacted in the same way by the same storm. Moreover,
8 storms vary in intensity. While some locations may experience multiple severe storm
9 events in a given year, others may go many years without any impact. In order to really
10 gauge the impact of system hardening, making the system more resilient, and improving
11 its switching capabilities, we must have enough time and data to normalize for these
12 variations, among other things. We are working on improving our use of data analytics to
13 assess investment impacts over time and as we get better and better data, we will use it to
14 inform future investment strategies and project decisions.

15 **Q. Dr. Marke takes one other approach in questioning the system**
16 **investments that are being made, that is, he implies that because of the existence of**
17 **the Covid-19 pandemic or general economic conditions among low-income customers**
18 **perhaps investments should not be made. Please address Dr. Marke's testimony in**
19 **this area.**

20 A. First, let me be clear that the Company is aware that some customers face
21 greater difficulty in paying their utility bills than others. We have many programs including
22 many funded with shareholder dollars to assist low-income customers. Ameren Missouri
23 witness Warren Wood discusses many of these in his direct testimony, and Page Selby

1 addresses some of these programs in her rebuttal testimony. Second, our statutory
2 obligation is to provide safe and adequate service, and it is our belief – and we firmly
3 believe the Commission would agree with this – that we need to maintain and operate a
4 system that provides a level of reliability consistent with the needs and expectations of all
5 of our customers, consistent with us being able to have a reasonable opportunity to earn a
6 fair return. I have outlined in detail above why the investments we are making are needed
7 to meet that obligation. Finally, the pandemic has shone an even brighter light on just how
8 critical highly reliable electricity is for everyone – including for low-income customers.
9 Many customers still work from home, at least a part of the time. Their devices will not
10 work if the power is not on, and they will not work right if the power quality is poor. Most
11 of their kids had to be schooled from home for long periods of time during the pandemic,
12 and while this is less true today, it remains true for many. Overall, consider that virtually
13 all of our customers depend on a digital world today – computers, appliances, electronics,
14 etc. They have much less tolerance for even momentary outages, which used to be normal,
15 as any outages at all are far more disruptive to customers than they used to be. This is not
16 the time *not* to invest in the system. It should also be kept in mind that we are investing at
17 a time when the cost of capital to do so is quite low by historical standards. Our authorized
18 weighted average cost of capital was set by the Commission in 2015 at 7.911%. It dropped
19 in our 2019 case (using the midpoint of the return on equity underlying the settlement of
20 our 2019 rate case, it was 7.116%), and it has dropped further given that our request in the
21 case is for an authorized weighted average cost of capital of 6.995%. Just as this has been
22 a good time for customers to improve their homes by taking advantage of low borrowing

1 rates, this too has been a good time to invest in the system at a cost of capital that is roughly
2 80 to 100 basis points lower than it was just a few years ago.

3 **Q. Aside from his overall expression of concerns, Dr. Marke notes three**
4 **specific areas of distribution system investments, undergrounding part of the system,**
5 **replacing 4kV substations, and voltage reduction programs. Please address each of**
6 **those topics.**

7 A. Dr. Marke appears to confuse the *replacement* of 400 miles of *existing* but
8 old, and as I discussed earlier degraded and flawed underground cable, with a plan that
9 does not exist to take existing overhead circuits and instead underground them.⁷ According
10 to a data request response from Dr. Marke, perhaps the wording of one of our SEP
11 publications gave him the wrong impression (it referred to "400 miles of new underground
12 cable"). Regardless, the cable would be new, but it *replaces* existing, old underground
13 cable.

14 **Q. What about replacing 4 kV substations?**

15 A. Early in the planning of the SEP, Ameren Missouri did consider whether it
16 should convert all its 4 kV substations to 12 kV in an effort to streamline operations and
17 achieve efficiencies. However, as part of our ongoing evaluation of projects, we determined
18 that conversions should only occur when (a) load is projected to grow beyond the capacity
19 that can be supported by the 4 kV system or voltage challenges exist with the 4kV system,
20 or (b) to eliminate "voltage islands." These islands represent parts of the system served at
21 a nonstandard voltage (2.4 kV for instance) from legacy systems acquired by Ameren

⁷ There may be isolated instances where a specific overhead circuit has significant reliability problems and where the only way to address the issue is to underground a part of that circuit, but there is no large-scale plan to underground existing overhead circuits.

1 Missouri in the past or 4 kV systems geographically surrounded by 12 kV systems which
2 we can't easily back up. These voltage islands present operating challenges as specialized
3 knowledge is needed in operating them and at times specialized equipment is needed to
4 repair the assets, which may prolong the length of an outage and also requires Ameren
5 Missouri to maintain additional equipment in inventory for these voltages outside the
6 standard 4 kV and 12 kV. Another significant problem with these voltage islands is that
7 when outages occur, there are limited to no rapid restoration abilities since we are unable
8 to tie an adjacent circuit at a different voltage together to restore service. We are not,
9 however, doing a wholesale replacement of 4 kV substations.

10 **Q. What about voltage reduction?**

11 A. Company witness James Huss addresses Dr. Marke's suggestion that
12 Ameren Missouri implement a voltage reduction program in his rebuttal testimony,
13 explaining why doing so does not make sense for Ameren Missouri.

14 **Q. Does this conclude your rebuttal testimony?**

15 A. Yes, it does.

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