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FILE NO. ER-2022-0337

DIRECT TESTIMONY

OF

JEFFREY R. HOLMSTEAD

ON

BEHALF OF

UNION ELECTRIC COMPANY

d/b/a AMEREN MISSOURI

**St. Louis, Missouri
August, 2022**

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jeffrey R. Holmstead. My business address is 201 M Street NW, Washington, D.C., 20036.

Q. What is your occupation?

A. I am an environmental lawyer and a partner at the law firm of Bracewell LLP, where I co-chair the firm’s Environmental Strategies Group.

Q. Please describe your educational background and relevant work experience.

A. I received my B.A. in Economics, *summa cum laude*, from Brigham Young University in 1984, and my J.D. from Yale Law School in 1987. From 1987 to 1988, I served as a law clerk to Judge Douglas H. Ginsburg on the U.S. Court of Appeals for the District of Columbia Circuit.

I began working on federal Clean Air Act (“CAA”) issues in 1989, when I joined the White House Staff of President George H.W. Bush. In the campaign leading up to the 1988 election, then Vice-President Bush had promised to push through new legislation to modernize the CAA, which had essentially remained unchanged since 1977. As a result of this campaign promise, the White House staff was very involved in the discussions that ultimately led to passage of the 1990 Amendments to the CAA, which created the current

1 version of the CAA. Because of my role in the White House, I was deeply involved in
2 efforts to implement the new 1990 CAA Amendments. From 1990 to early 1993, I was one
3 of two White House staffers assigned to work with EPA on various CAA regulations.

4 I left the White House in early 1993 and shortly thereafter joined the law firm of
5 Latham & Watkins, where I became a partner in the firm's environmental group. I was in
6 this position until 2001, when I was appointed as the Assistant Administrator for Air and
7 Radiation at the U.S. Environmental Protection Agency ("EPA"). I served in this position
8 until August of 2005. In this capacity, I was the senior official in charge of implementing
9 all the regulatory and permitting programs of the CAA. During my tenure at EPA, I
10 oversaw and was intimately involved in developing a number of CAA regulations,
11 including some of the New Source Review ("NSR") regulations at issue in the Ameren
12 Missouri litigation in the U.S. District Court for the Eastern District of Missouri.

13 Since 2006, I have been a partner at Bracewell LLP, where my practice is focused
14 on issues arising under the CAA, including the NSR program. A copy of my CV is attached
15 as Schedule JRH-D1.

16 **Q. How long have you been working on issues related to the federal Clean**
17 **Air Act?**

18 A. Since 1989, I have spent most of my professional career working on CAA
19 issues.

20 **II. PURPOSE OF TESTIMONY**

21 **Q. Why have you been asked to testify in this proceeding?**

22 A. I have been asked to testify regarding Ameren Missouri's decisions not to
23 seek NSR permits when it undertook the projects at the Rush Island Plant that gave rise to

1 the District Court’s decision – namely, (1) the projects performed during the Unit 1 outage
2 in early 2007 (“Unit 1 Projects”); and (2) the projects performed during the Unit 2 outage
3 in early 2010 (“Unit 2 Projects”). I will refer to the Unit 1 Projects and the Unit 2 Projects
4 collectively as “the Rush Island Projects.”

5 **Q. Please provide a summary of your testimony and opinions.**

6 A. I can summarize my testimony and opinions as follows:

7 • I have reviewed a number of documents related to Ameren Missouri’s
8 determinations that it did not need to obtain NSR permits for the Rush Island
9 Projects. As reflected in these materials, the Company had three independent
10 reasons for these determinations:

11 1. Under the applicable Missouri regulations as they had been interpreted
12 by the Missouri Department of Natural Resources (“DNR”), an NSR
13 permit was not required unless a project would cause an increase in
14 “potential emissions” at a facility, and none of the Rush Island Projects
15 would increase potential emissions.

16 2. None of the Rush Island Projects would be expected to cause an increase
17 in actual annual emissions and thus would not trigger NSR.

18 3. These same types of projects were done routinely throughout the
19 industry. The Rush Island Projects were therefore considered “routine
20 maintenance, repair and replacement” (“RMRR”), which is explicitly
21 exempt from NSR.

22 • When Ameren Missouri determined that it did not need NSR permits for any of
23 the Rush Island Projects, each of these conclusions was reasonable, given what

1 Ameren Missouri knew or should have known at the time. Ameren Missouri
2 was not alone in determining that it did not need NSR permits for the types of
3 projects the Company undertook at Rush Island between 2005 and 2010. Many
4 other companies that owned or operated coal-fired power plants had done the
5 same types of projects at their plants, and none of them had ever applied for or
6 obtained an NSR permit for any of these projects. Based on the materials I have
7 reviewed and my knowledge of EPA’s regulations, if I had been advising
8 Ameren Missouri at the time, I would have agreed that the Company did not
9 need an NSR permit for any of the Rush Island Projects.

10 **III. THE CLEAN AIR ACT AND ITS NEW SOURCE REVIEW PROGRAM**

11 **Q. What is the federal Clean Air Act?**

12 A. The Clean Air Act (CAA for short) was originally enacted in 1970,
13 expanded in 1977, and substantially expanded in 1990. Under the CAA, EPA and states
14 regulate virtually every imaginable source of air pollution, including both “stationary
15 sources” (such as power plants, industrial facilities and dry-cleaning operations) and
16 “mobile sources” (such as cars, trucks, buses, and construction equipment). There are also
17 CAA regulations that cover things such as leaf blowers, lawn mowers, paints and coatings,
18 and consumer products such as hair spray and deodorant.

19 **Q. Who is charged with implementing the Clean Air Act’s requirements?**

20 A. EPA implements some programs directly, but a number of CAA programs
21 are based on the principle of “cooperative federalism,” under which EPA provides broad
22 standards and individual states have considerable discretion in choosing how to meet these
23 standards. States develop their own versions of the basic federal programs and submit

1 them to EPA for approval. Once EPA reviews and approves these programs, they become
2 part of the “state implementation plans” (known as SIPs) that are a key feature of the CAA.
3 Once these state programs are approved by EPA, the requirements of these programs
4 displace the federal regulations that would otherwise apply in the individual states, and
5 industrial facilities within each state are governed by the EPA-approved state programs.
6 This was the case for Missouri, which administered the CAA under an EPA’s approved
7 SIP.

8 **Q. What is the CAA’s New Source Review program?**

9 A. As its name implies, the New Source Review program is focused primarily
10 on new sources of emission and ensures that new power plants and other new industrial
11 sources are designed and built with modern pollution controls. It does so by requiring a
12 permit for construction of new major sources of emissions. In issuing that permit for
13 construction, the permitting authority (usually a state environmental agency) will identify
14 the “best available control technology” (“BACT”) that can be used to control emissions
15 and then determine the emission limit that the source can meet by using that technology.
16 This emission limit is incorporated as a legal requirement in the source’s NSR permit.

17 The NSR program also applies to existing power plants, but only if they undergo a
18 major modification that will cause a significant increase in emissions. There are many other
19 CAA programs that are specifically designed to reduce emissions from existing power
20 plants.

21 There are actually two different parts of the NSR program: (1) the Nonattainment
22 New Source Review (“NNSR”) program, which applies to plants located in nonattainment
23 areas (i.e., areas with air quality that does not meet the EPA national ambient air quality

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1 standards); and (2) the Prevention of Significant Deterioration (“PSD”) program, which
2 applies to plants located in attainment areas (i.e., areas that meet the EPA’s air quality
3 standards). During the relevant time period, the area around the Rush Island Plant met the
4 EPA’s air quality standards for all pollutants, so it was subject only to the PSD program.
5 The main purpose of the PSD program is to ensure that new plants or major modifications
6 at existing plants will not cause a “significant deterioration” of air quality in areas that meet
7 EPA’s air quality standards.

8 Regulators and others who work on CAA issues often refer to both the PSD and the
9 NNSR programs together as “the NSR program.” I will adopt this custom and refer
10 generally to the “NSR program” and the “NSR requirements,” even though the Rush Island
11 Plant was subject only to the PSD requirements of the NSR program during the relevant
12 time period (because the air quality in the area around the plant met all EPA air quality
13 standards).

14 **Q. At an existing source like the Rush Island Plant, when would the NSR**
15 **program apply?**

16 A. The NSR program is referred to as a “construction” or “pre-construction”
17 permitting program. If a company wants to build a facility that will be a “major source” of
18 emissions as defined under the Clean Air Act, then that company must obtain an NSR
19 permit before it can begin construction on the facility. The same requirement applies to
20 any company that wants to make a modification to an existing plant that will cause a
21 significant increase in emissions – known as a “major modification” under EPA’s NSR
22 regulations. The company must go through the NSR permitting process and obtain a permit
23 before it can begin construction on the major modification. In either case—construction

1 of a new source of emissions or a “major modification” of an existing source of
2 emissions—the NSR program requires the permit to incorporate emissions limits based on
3 up-to-date pollution control technology.

4 **Q. What does the Clean Air Act say about when an existing source, like**
5 **Rush Island, must get an NSR permit?**

6 A. The statutory language of the CAA simply says that an NSR permit is
7 needed for any “modification” of an existing source, and modification is defined as “any
8 physical change in, or change in the method of operation of, a stationary source which
9 increases the amount of any air pollutant emitted by such source or which results in the
10 emission of any air pollutant not previously emitted.” 42 U.S.C. § 7411(a)(4). As EPA
11 has noted, this definition essentially creates a two-part test that a plant operator must use
12 in order to determine the applicability of NSR requirements to any particular project at an
13 existing stationary source: (1) is there a physical or operational change? and (2) would that
14 change cause the specified emission increase? 67 Fed. Reg. 80186, 80187 (Dec. 31, 2002)
15 (preamble to proposed rule). Although there are a few regulatory complexities that
16 sometimes come into play, if the answers to both questions are “yes,” then that project is
17 said to “trigger” NSR and permitting is required.

18 **Q. What steps has EPA taken to explain and implement that NSR trigger?**

19 A. Over the last 30 years, EPA has issued a number of rules regarding the types
20 of projects at existing sources that “trigger” the need for an NSR permit. These rules all
21 deal with the question of “applicability” – how to determine if an NSR permit is needed
22 for a particular project or activity at an existing plant. EPA’s NSR rules implement the
23 basic two-part definition of “modification” in the CAA that I mentioned above. As EPA

1 has explained:

2 The reference to “any physical change * * * or change in the method
3 of operation” in section 111(a)(4) of the Act [42 U.S.C. §
4 7411(a)(4)] could—read literally—encompass the most mundane
5 activities at an industrial facility (even the repair or replacement of
6 a single leaky pipe, or an insignificant change in the way that pipe
7 is utilized). However, the EPA has recognized that Congress did not
8 intend to make every activity at a source subject to major new source
9 requirements As a result, the EPA has adopted several
10 exclusions from the “physical or operational change” component
11 of the definition. For instance, the EPA has specifically recognized
12 that routine maintenance, repair and replacement, and changes in
13 hours of operation or in the production rate are not by themselves
14 considered a physical change or change in the method of operation
15 within the definition of major modification. The EPA has likewise
16 limited the reach of the second step of the statutory definition of
17 modification by excluding all changes that do not result in an
18 emissions increase above “significance” levels for the pollutant in
19 question. Taken together, these regulatory limitations restrict the
20 application of the NSR program . . . to only “**major modifications**”
21 at existing major stationary sources.

22 61 Fed. Reg. at 38,250 (July 23, 1996) (preamble to proposed rule) (internal citations
23 omitted, emphasis added).

24 **Q. How has EPA applied the regulatory definition of “major**
25 **modification” to activities at existing power plants?**

26 A. Prior to 1988, EPA and the power industry generally viewed all replacement
27 of existing plant components with functionally equivalent components as “routine
28 maintenance, repair and replacement” (RMRR) and thus excluded from NSR. Before that
29 time, there had never been an instance in which EPA, a state agency, or any court had found
30 that an NSR permit was required for the replacement of functionally equivalent
31 components at an operating power plant, even though such replacements were common in
32 the industry.

1 In September of that year, however, EPA staff evaluated the applicability of the
2 NSR program to a project to be undertaken at a Wisconsin Electric Power Company
3 (“WEPCO”) power plant and determined that it would be a major modification. This is
4 known as the WEPCO decision and was the first time that an existing power plant was
5 required to get an NSR permit.

6 **Q. What was the WEPCO decision?**

7 A. WEPCO had proposed to undertake a large project that involved replacing
8 a number of components at a power plant that consisted of five coal-fired boilers, and EPA
9 was asked to determine whether the proposed project would trigger NSR. The EPA staff
10 determined that the project was not RMRR and that it would cause an increase in emissions
11 that would exceed EPA’s “significance” levels and would thus be a “major modification”.
12 The Company appealed this “applicability determination” to the EPA Administrator (the
13 head of EPA), arguing that it was simply replacing old components with functionally
14 equivalent components, but in October 1988 he reaffirmed the EPA staff determination,
15 noting that the project was very extensive and could not be viewed as routine. As described
16 by EPA, the project that WEPCO had proposed for five different generating units at the
17 plant consisted of the following:

18 Each unit was rated at 80 megawatts of electrical output capacity.
19 The activity involved the replacement of numerous major
20 components. The information submitted by WEPCO showed that
21 the company intended to replace several components that are
22 essential to the operation of the Port Washington plant. In particular,
23 WEPCO sought to replace the rear steam drums on the boilers at
24 units 2, 3, 4, and 5. According to WEPCO, these steam drums were
25 a type of “header” for the collection and distribution of steam
26 and/or water within the boilers. WEPCO viewed their replacement
27 as necessary to continue operation of the units in safe condition. In
28 addition, at each of the emissions units, WEPCO planned to repair
29 or replace several other integral components, including replacement

1 of the air heaters at units 1, 2, 3, and 4. WEPCO also planned to
2 renovate major mechanical and electrical auxiliary systems and
3 common plant support facilities. WEPCO intended to perform the
4 work over a 4-year period, utilizing successive 9-month outages at
5 each unit. The cost of the activity was estimated in 1988 to be \$87.5
6 million. . . . EPA concluded at the time this activity was
7 unprecedented in that EPA did not find a single instance of
8 renovation work at any electric utility generating station that
9 approached this activity in nature, scope and extent.

10 68 Fed. Reg. at 61,256–61,257. In reaching the decision that the WEPCO project was
11 unprecedented in the electric utility industry, and therefore not RMRR, EPA “weigh[ed]
12 the nature, extent, purpose, frequency, and cost of the work, as well as other relevant
13 factors, to arrive at a common-sense finding” that the proposed project was not routine in
14 the industry. The Administrator also agreed that the proposed project would result in a
15 significant emission increase, thus making it a “major modification” that would require an
16 NSR permit.

17 **Q. What happened next?**

18 A. The company appealed the Administrator’s decision to the U.S. Court of
19 Appeals for the Seventh Circuit. The court upheld EPA’s determination that the project
20 proposed by WEPCO was not routine replacement (i.e., not RMRR). On the other hand,
21 the Court disagreed with the method EPA had used to determine whether the project would
22 cause an increase in emissions and remanded this issue back to the Agency.

23 The utility industry expressed concern that the WEPCO decision on RMRR might
24 result in many component-replacement projects, which they viewed as routine, being
25 regulated by the NSR program. The WEPCO decision came out during the congressional
26 deliberations over the 1990 CAA Amendments, and a number of members of Congress
27 raised these concerns as part of this process. In response, the Government Accountability
28 Office (“GAO”) did a study which found that the WEPCO project was highly unusual and

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1 that most power plant replacement and repair projects would be less extensive. The
2 Chairman of the House Energy and Commerce Committee (which was responsible for
3 overseeing EPA) also sent a letter to EPA asking EPA to explain the scope of the WEPCO
4 applicability determination and its implications for other power plants.

5 In his response to this letter, the then-EPA Assistant Administrator for Air and
6 Radiation, the senior EPA official in charge of implementing the CAA (and one of my
7 predecessors at EPA), reassured the Chairman and other member of Congress that the
8 WEPCO decision would not have a significant impact on other power plants. His letter
9 stated:

10 As indicated in the GAO report, it is expected that most utility
11 projects will not be similar to the WEPCO situation. That is, EPA
12 believes that most utilities conduct an ongoing maintenance
13 program at existing plants which prevents deterioration of
14 production capacity and utilization levels.

15 He went on to state that “the ruling is not expected to significantly affect power
16 plant life extension projects” and that “EPA’s WEPCO decision only applies to utilities
17 proposing ‘WEPCO type’ changes.” Letter dated June 19, 1991, from EPA Assistant
18 Administrator William Rosenberg to Chairman John Dingell.

19 **Q. How did EPA respond to the WEPCO decision?**

20 A. EPA issued a new rule in response to the decision known as the “WEPCO
21 Rule.” Although the Seventh Circuit had upheld EPA’s determination that the project
22 proposed by WEPCO was not RMRR, it disagreed with EPA’s approach for determining
23 whether the project would result in a significant emission increase (and thus be a “major
24 modification” that required an NSR permit). As noted above, the utility industry also had
25 concerns that the approach EPA used for WEPCO might cause many equipment-
26 replacement projects, which they viewed as routine, to be regulated by the NSR program.

1 To address both these issues (as well as to adjust the NSR program to reflect the recently
2 enacted 1990 CAA Amendments), EPA went through notice-and-comment rulemaking to
3 clarify the way the federal NSR program would apply to existing power plants, including
4 its approach to RMRR. The final WEPCO Rule was issued in 1992.

5 On the issue of RMRR, EPA deferred promulgating a formal regulatory definition
6 of RMRR under the WEPCO Rule. Instead, EPA noted that:

7 the issue has an important bearing on today's rule because a project
8 that is determined to be routine is excluded by EPA regulations from
9 the definition of major modification. For this reason, EPA plans to
10 issue guidance on this subject as part of a NSR regulatory update
11 package which EPA presently intends to propose by early summer.
12 In the meantime, EPA is today clarifying that the determination of
13 whether the repair or replacement of a particular item of equipment
14 is "routine" under the NSR regulations, while made on a case-by-
15 case basis, must be based on the evaluation of whether that type of
16 equipment has been repaired or replaced by sources within the
17 relevant industrial category.

18 57 Fed. Reg. 32,314, 32,326 (July 21, 1992) (preamble to final rule).

19 **Q. What did the WEPCO Rule say about how to determine whether a**
20 **project would result in a significant increase in emissions?**

21 A. The WEPCO Rule clarified the way in which companies and regulators
22 should determine whether projects at existing power plants (referred to as “electric utility
23 steam generating units”) would result in an emission increase. For one thing, the Rule
24 explicitly reaffirmed EPA’s view that a project would trigger NSR only if it “caused” an
25 increase in emissions. Here is the way EPA discussed this issue in the Rule:

26 The NSR regulatory provisions require that the physical or
27 operational change "result in" an increase in actual emissions in
28 order to consider that change to be a modification [see e.g., 40 CFR
29 52.21(2)(i)]. In other words, NSR will not apply unless EPA finds
30 that there is a causal link between the proposed change and any post-
31 change increase in emissions.

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1 * * * * *

2 Consequently, where projected increased operations are in response
3 to an independent factor, such as demand growth, which could have
4 occurred and affected the unit's operations during the representative
5 baseline period even in the absence of the physical or operational
6 change, the increased operations cannot be said to result from the
7 change and therefore may be excluded from the projection of the
8 unit's future actual emissions.

9 57 Fed. Reg. at 32,326, 32,327.

10 The WEPCO Rule also clarified the way in which post-project emissions should be
11 calculated at existing power plants. See 67 Fed. Reg. at 80,188. In the WEPCO case, EPA
12 had argued that a plant owner had to assume that, after any type of change, the plant would
13 operate at full capacity, 24-hours-a-day, 365-days-a-year. Thus, post-project emissions at
14 existing power plants were based on the unit's maximum "potential-to-emit" after the
15 change. To determine whether a project would cause a significant increase in emissions,
16 the annual emissions that would occur if the plant operated at full capacity for 365-days-a-
17 year were compared to the plant's actual annual emissions prior to the change. This is
18 referred as the "actual-to-potential test." Under this test, any project is predicted to result
19 in an emission increase because no unit actually operates round the clock for 365-days-a-
20 year, meaning that future emissions are always predicted to be higher than past emissions.

21 The WEPCO court found that this test was unreasonable and that past actual
22 emissions had to be compared with projected actual emissions in the future. The WEPCO
23 Rule provided that pre-project actual emissions (often referred to as "baseline emissions"
24 or the "baseline") should be compared to the emissions that were actually expected to occur
25 in the future, referred to under the rule as "representative actual annual emissions." 57 Fed.
26 Reg. at 32,337.

1 **Q. Did EPA issue any subsequent NSR regulations that are relevant here?**

2 A. Yes. In the 2002 NSR Reform Rule, EPA clarified how to compare past
3 emissions with future emissions for purposes of determining whether a project (*i.e.*, a
4 physical change at a facility) would cause an emission increase and thus potentially trigger
5 NSR. When it comes to past annual emissions, power plants can select the highest total
6 emissions during any consecutive 24-month period in the five years leading up to the
7 change, and then divide that number by two to calculate “baseline emissions.” This number
8 represents past annual emissions.

9 When estimating future annual emissions (*i.e.*, what the annual emissions will be
10 after the change), the rules are less prescriptive. They say that the plant must project what
11 annual emissions will be for every 12-month period, on a rolling basis, for at least five
12 years after the change. If a change will increase the capacity of the unit, then the plant
13 must estimate future emissions on a 12-month rolling basis for 10 years after the change.
14 If the projected future annual emissions in all the 12-month periods are always lower than
15 the baseline emissions, then that’s the end of the analysis. If estimated future emissions in
16 any 12-month period are higher than the baseline emissions, you then move on to the next
17 step in the applicability analysis, which is designed to determine whether this increase is
18 caused by the project.

19 When EPA proposed these rules, it got public comments asking the agency to
20 specify particular methods that should be used to estimate future emissions. EPA decided
21 that doing so would not be feasible. As EPA explained when responding to these
22 comments, environmental regulators could never understand all the factors that might
23 affect future emissions because this would depend in large part on business issues. EPA

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1 did, however, require companies to take a number of specific factors into account when
2 projecting future emissions. The regulations provide that:

3 In determining the projected actual emissions . . . (before beginning
4 actual construction), the owner or operator of the major stationary
5 source:

6 (a) Shall consider all relevant information, including but not limited
7 to, historical operational data, the company's own representations,
8 the company's expected business activity and the company's highest
9 projections of business activity, the company's filings with the State
10 or Federal regulatory authorities, and compliance plans under the
11 approved State Implementation Plan.

12 67 Fed. Reg. at 80,277 (preamble to final rule).

13 While the rules require consideration of these factors, it is important to note that
14 EPA did not prescribe a particular methodology or formula that must be used in projecting
15 future emissions. In fact, EPA specifically declined to do so. The understanding was that,
16 if companies made such projections after considering all the relevant factors, regulators
17 would not second guess them as long as these projections were reasonable. Technical
18 Support Document (Response to Comments) for the Prevention of Significant
19 Deterioration and Nonattainment Area New Source Review Regulations (Nov. 2002), at I-
20 5-27, *available at* [https://www.epa.gov/sites/default/files/2015-12/documents/nsr-tds_11-](https://www.epa.gov/sites/default/files/2015-12/documents/nsr-tds_11-22-02.pdf)
21 [22-02.pdf](https://www.epa.gov/sites/default/files/2015-12/documents/nsr-tds_11-22-02.pdf).

22 **Q. Is this the end of the applicability analysis?**

23 A. As I said, if the projected future annual emissions in all future 12-month
24 periods are always lower than the baseline emissions, then that's the end of the analysis.
25 Otherwise, the next step is to consider whether the projected increase in emissions is
26 actually caused by the project.

1 Annual emissions at an industrial facility change from year to year for reasons that
2 have nothing to do with any changes at the facility itself. Emissions might increase
3 substantially from one year to the next even though the facility remains entirely unchanged.
4 At a power plant, annual emissions depend primarily on how often and how hard it is called
5 upon to operate, which depends on a number of things, including weather, the number and
6 operating status of other power plants in the area, the transmission infrastructure, and
7 overall economic activity. The Clean Air Act is clear that a project will trigger NSR only
8 if it will “cause” an emission increase. So, if an emission increase is not caused by the
9 project, it does not trigger NSR.

10 The 2002 NSR Reform Rule addresses this causation requirement with an
11 additional step. If your projections show an increase above baseline emissions after a
12 proposed project, you must subtract the emissions that (1) “could have been accommodated
13 during the baseline period” and (2) “that are also unrelated to the particular project,
14 including any increased utilization due to product demand growth.” *Id.* at 80,277.

15 **IV. NSR APPLICABILITY AND APPROVED STATE PROGRAMS**

16 **Q. Do all state programs have identical NSR applicability provisions?**

17 A. No. As noted above, individual states are given the opportunity to develop
18 their own unique NSR programs. If EPA approves these programs as part of the State’s
19 SIP, then the State’s regulations displace EPA’s NSR regulations and apply to all facilities
20 located within that state, which, as noted earlier, was the case in Missouri when Ameren
21 Missouri was undertaking the Rush Island Projects. Over the years, individual states have

1 developed their own NSR applicability provisions that in some cases are different from
2 those in EPA’s regulations, and these provisions have been incorporated into SIP-approved
3 NSR programs.

4 **Q. Can you provide some examples of the variability in NSR applicability**
5 **provisions in different state programs?**

6 A. One example is the Clark County, Nevada SIP. From 1981 to 2004, the
7 approved Clark County SIP included a “potential-to-potential” test for determining
8 whether a project would be a modification for purposes of NSR. It defined a
9 “modification” as “any physical change in or change in the method of operation of an
10 existing stationary source which increases or may increase *the potential to emit* for any air
11 contaminant by any emission unit in the stationary source” District Board of Health
12 Clark County Air Pollution Control Regulations Section 1.58 (emphasis added) (Revised
13 9/3/81). “Potential to emit” was defined as “the maximum capacity of a stationary source
14 to emit a pollutant under its physical and operational design” Id. at Section 1.80
15 (Revised 9/3/81).

16 In my experience, some regulators prefer this “potential-to-potential” approach
17 because it is an objective test that is easy to apply. If a project changes the physical
18 characteristics of an emission unit in a manner that would increase its size or capacity to
19 emit, it is reasonable to assume that it would likely cause an emission increase and should
20 go through further regulatory analysis. If a project does not increase the size or capacity
21 of an existing unit, it is “screened out” and there is no need to do a projection of future
22 emissions.

1 By the mid-1990s, EPA began to urge Clark County to eliminate the potential-to-
2 potential test. In the meantime, EPA developed the NSR Reform Rule and promulgated
3 changes to the emissions applicability test at the end of 2002. In 2004, Clark County
4 submitted a new SIP that EPA found would “establish the more inclusive test (‘actual to
5 potential’) for evaluating source modifications and thereby replace the existing SIP NSR
6 program’s ‘potential-to-potential’ test, with the result that a greater number of source
7 modifications would be subject to new source review.” 69 Fed. Reg. at 31,064. However,
8 the existing “potential-to-potential” applicability provision remained part of the SIP-
9 approved program until September 2004, when the revised regulations were approved by
10 EPA and incorporated into the Clark County SIP. 69 Fed. Reg. at 54,006.

11 The State of Connecticut also had a similar (but more complicated) set of
12 applicability provisions in its SIP-approved NSR program. Under the 1989 Connecticut
13 regulations, “modify” or “modification” means “any physical change in, change in the
14 method of operation of, or addition to a stationary source which: (i) increases the potential
15 emissions of any individual air pollutant from a stationary source by five (5) tons per year
16 or more; or (ii) increases the maximum rated capacity of the stationary source unless the
17 owner or operator of the stationary source demonstrates to the commissioner’s satisfaction
18 that such increase is less than fifteen percent (15%) and the change or addition does not
19 cause an increase in the actual emissions or the potential emissions; or (iii) increases the
20 potential emissions above [certain levels].” EPA approved these definitions into the state’s
21 SIP-approved NSR program in 1993. 58 Fed. Reg. 10,957, 10,963 (Feb. 23, 1993). As was
22 the case in Nevada, EPA later urged the state to change its applicability provisions, and

1 EPA ultimately approved a SIP that changed the State’s definition of modification. As

2 EPA explained in proposing to approve the new definition,

3 [Connecticut’s] existing SIP-approved rules use a different
4 approach for calculating the emission increase from a modification.
5 Instead of the actual-to-potential test, the DEP uses the potential-to-
6 potential test. This method compares the emission unit’s potential
7 before the modification with its potential after the modification. The
8 DEP also does not allow sources the option to take credit for
9 emission changes occurring source-wide. Adopting provisions that
10 reflect the EPA rules that are currently in effect significantly
11 improves Connecticut’s program.

12 68 Fed. Reg. 2722, 2724 (Jan. 21, 2003). EPA approved the revised SIP shortly after its
13 proposal. 68 Fed. Reg. 9009 (Feb. 27, 2003).

14 **Q. And Missouri also has a SIP-approved NSR program?**

15 A. Yes. The Missouri Department of Natural Resources, usually referred to as
16 the Missouri DNR, is responsible for implementing Missouri’s SIP-approved NSR
17 program

18 **Q. Please describe the NSR applicability provisions in Missouri’s SIP-**
19 **approved program.**

20 A. Missouri’s SIP-approved NSR program, 10 CSR 10-6.060 and 10-6.061,
21 contains the permitting regulations that applied to Rush Island during the relevant time
22 period. Not all projects undertaken at a source like Rush Island are subject to permitting
23 requirements. Missouri’s construction permit rules serve to identify “sources which are
24 required to obtain permits to construct” and “establish[] requirements to be met prior to
25 construction or modification of any of these sources.” 10 CSR 10-6.060 (Purpose) (Nov.
26 30, 2006). The construction permit rules include applicability provisions to establish when

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1 sources are required to obtain permits to construct, including minor (referred to as “de
2 minimis”) permits, nonattainment NSR permits, PSD permits, and hazardous air pollutant
3 permits.

4 The threshold applicability provisions for Missouri’s permitting program are set
5 forth under the heading, “Construction Permits Required – Applicability.” Section (1)(C)
6 of these regulations state that “[n]o owner or operator shall commence construction or
7 modification of any installation subject to this rule . . . without first obtaining a permit from
8 the permitting authority under this rule.” 10 CSR 10-6.060(1)(C) (emphasis added) (Nov.
9 30, 2006). This tells us that construction permits (whether de minimis, nonattainment, PSD
10 or hazardous) are required only when there will be “construction” or “modification” of a
11 facility covered by the rule. Conversely, if the project or activity in question does not
12 constitute “construction” or “modification,” then the rules do not apply and the activity
13 does not require any form of construction permit.

14 Under the Missouri SIP, a “modification” occurs only when the project will cause
15 an increase in potential emissions. Similar to the Nevada program, the Missouri SIP defines
16 “modification” as a physical or operational change of “a source operation” that causes an
17 “increase in potential emissions of any air pollutant emitted by the source operation.” 10
18 CSR 10-6.020(2) (M)(10)(emphasis added) (Nov. 30, 2006). “Source operation” is defined
19 as “[a]ny part or activity of an installation that emits or has the potential to emit any
20 regulated air pollutant or any pollutant listed under section 112(b) of the Act.” 10-
21 6.020(2)(E)(4), (2)(S)(16) (Nov. 30, 2006). The Missouri SIP defines potential emissions
22 as “[t]he emission rates of any pollutant at maximum design capacity.” 10 CSR 10-
23 6.020(2)(P)(19) (Nov. 30, 2006). Thus, a project is a modification only if it will cause an

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1 increase in the emission rate when the source is operating at its maximum design capacity.
2 If not, then the regulations tell us that the project is not subject to Missouri's construction
3 permitting regulations, meaning that the source is not required to obtain a construction
4 permit for the project before beginning construction or modification. Thus, the project is
5 "screened out" at this point.

6 After this step, the Missouri NSR program is essentially the same as the EPA NSR
7 program because the State, in 2006, incorporated the regulatory language from EPA's 2002
8 NSR Reform Rules into its SIP-approved program. Thus, if a project will cause an increase
9 in potential emissions (and will therefore be a "modification"), the source must then
10 determine whether it will cause a significant increase in actual emissions and therefore be
11 a "major modification" that requires an NSR permit under 10 CSR 10-6.060(8). As
12 discussed below, when Ameren Missouri determined that it did not need NSR permits for
13 the Rush Island Projects, this is how the Missouri DNR applied the EPA-approved SIP
14 permitting rules, as Ameren Missouri was well aware.

15 In the NSR enforcement case against Ameren Missouri, however, the EPA
16 enforcement office argued, and the District Court found, that a project could be a "major
17 modification" even if it was not a "modification." But just because a court adopted this
18 interpretation of the SIP years after Ameren Missouri completed the Rush Island Projects
19 does not mean that the reading of the SIP that I have outlined above was unreasonable
20 before that time. To the contrary, the Missouri DNR, which is responsible for implementing
21 the State's NSR program, read them the same way at that time, as discussed below, and it
22 was the Missouri DNR that had responsibility for administering the CAA under the

1 Missouri SIP that EPA had approved. Those were the facts in front of Ameren Missouri
2 and upon which it made its decision that NSR permits were not required.

3 Based on my experience as the head of EPA's Air Office and someone who has
4 worked on Clean Air Act regulations for more than 30 years, the reading I have outlined
5 above is how I would have read and understood the regulations before the District Court's
6 decision in the enforcement case. And as I mentioned, this reading was also supported by
7 MDNR. I believe that, before the District Court's later decision, this was clearly the most
8 reasonable way to interpret the NSR permitting regulations in the Missouri SIP.

9 **Q. How would you apply this reading of the Missouri SIP to make an NSR**
10 **applicability determination concerning a project at an existing power plant?**

11 A. In any NSR applicability determination, there are basically two questions:
12 (1) Will a proposed project be a "physical change or change in the method of operation"?
13 and (2) will the project cause an increase in emissions? You don't trigger NSR unless the
14 answer to both questions is "yes." Although you can conclude that an NSR permit is not
15 required if the answer to either question is "no," sources generally examine both questions
16 out of an abundance of caution.

17 **Q. How does an owner or operator determine if there will be a physical**
18 **change at a facility?**

19 A. As I testified earlier, EPA has repeatedly said that "physical change or
20 change in the method of operation" is a broad concept that could conceivably cover almost
21 anything done at a facility, like changing out a filter. So the analysis of whether a particular
22 project or activity is a physical or operational change is primarily an analysis of whether
23 the project falls within one of the exclusions found in the SIP-approved NSR rules. Under

1 the SIP-approved Missouri NSR rules, the excluded project categories include an increase
2 in hours of operation or production rates (if not explicitly prohibited by permit) and, most
3 importantly, RMRR. When evaluating the type of maintenance and repair work typically
4 performed during an outage, the question of whether such work constitutes a “physical
5 change” turns on whether it qualifies as RMRR.

6 **Q. If a proposed project is not RMRR (and thus is a physical change), how**
7 **does the owner or operator determine whether the project will cause the necessary**
8 **increase in emissions?**

9 A. As discussed above, before the District Court’s ruling in the Ameren
10 Missouri case, the Missouri rules were read to establish a two-step process. Under Step
11 One, the owner or operator must determine whether the project constitutes a “modification
12 of any installation subject to this rule” in accordance with 10 CFR 10-6.060(1)(C). The SIP
13 defines “modification” as a physical or operational change of a source operation that causes
14 an increase in potential emissions from the source. *See* 10 CFR 10-6.020(2) (emphasis
15 added). Potential emissions are defined as the emission rate of a pollutant “at maximum
16 design capacity.” 10 CFR 10-6.020(2)(P)(19). If a project doesn’t increase the emissions
17 at maximum design capacity, then the regulations tell us that it is screened out at this step.
18 Again, I recognize that the District Court later determined that this step does not apply to
19 NSR permitting, and the U.S. Court of Appeals for the Eighth Circuit affirmed that result
20 on appeal. But that does not change my opinion that this was the most reasonable reading
21 of the Missouri SIP at the time Ameren Missouri made its preconstruction decisions. This
22 is how MDNR had interpreted and applied the SIP prior to the time Ameren Missouri made
23 its decisions. As someone who has been involved in drafting and interpreting

1 environmental regulations for more than 30 years, I would have agreed with the state's and
2 Ameren Missouri's readings at that time.

3 Step Two under the Missouri SIP mirrors EPA's 2002 NSR Reform Rule. The
4 regulations tell us that if a project is deemed a "modification" in Step One (because it will
5 increase potential emissions), then the project must be evaluated to determine if it is a
6 "major modification" under the Missouri SIP.

7 As I testified earlier, EPA's 2002 NSR Reform Rule codified a framework for
8 evaluating whether a physical or operational change will cause a significant emission
9 increase. That framework compares the baseline actual emissions prior to the change to the
10 projected actual emissions after the change. The actual-to-projected-actual methodology
11 from the NSR Reform Rule was adopted into the Missouri SIP in 2006 and was available
12 for use by Ameren Missouri in evaluating the Rush Island Projects.

13 As noted, the 2002 NSR Reform Rule does not prescribe a particular calculation or
14 formula that must be used for these analyses. EPA explicitly declined to do so and
15 recognized that owners and operators will have discretion in making these calculations,
16 provided that they satisfy the objective requirements of the rule.

17 While EPA did not specify a calculation method that must be used with the actual-
18 to-projected-actual emissions test, EPA did attempt to ensure that the calculated increase
19 between the baseline emissions (pre-change) and projected actual emissions (post-change)
20 focuses on the increase *caused by* the change. For example, if a source experiences an
21 increase in emissions after a project, but that increase is unrelated to the change – for
22 example, if the source experiences increased utilization due to demand growth, and the
23 source was capable of operating at that increased utilization level prior to the change – that

1 unrelated emission increase must be excluded when comparing the project emission
2 increase to the applicable significance threshold.

3 If a project is a physical or operational change that causes an increase in emissions,
4 and the difference between the source's baseline actual emissions and projected actual
5 emissions exceeds the applicable significance threshold, that change is a "major
6 modification" that triggers NSR.

7 **Q. Will an owner or operator be required to exercise engineering
8 judgment or discretion in making this determination?**

9 A. Yes. In comments on the proposed 2002 NSR reforms, some parties argued
10 that EPA should include a specific methodology for projecting future emissions. EPA
11 explained, however, that this was not appropriate or even feasible and instead recognized
12 that companies would be in the best position to make such projections.

13 **V. AMEREN MISSOURI'S APPLICABILITY DETERMINATIONS**

14 **Q. Have you been asked to evaluate some of Ameren Missouri's past NSR
15 applicability determinations for this proceeding?**

16 A. Yes.

17 **Q. What information have you relied upon in evaluating these
18 determinations?**

19 A. I have relied on:

- 20 • the text of the Missouri SIP-approved NSR regulations;
- 21 • the history of the NSR program, including the WEPCO decision, the WEPCO
- 22 rule, and the 2002 NSR Reform Rule;

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- 1 • the implementation of the NSR program by Missouri and other states through
2 SIPs;
- 3 • the interpretations and actions by Missouri DNR concerning its SIP and NSR
4 requirements under that SIP;
- 5 • the state of the law at the time the decisions were made;
- 6 • the testimony and declarations of Ameren Missouri employees and MDNR
7 representatives in the underlying District Court litigation; and
- 8 • my more than 30 years of experience dealing with NSR issues as a government
9 official and a lawyer in private practice.

10 I am not relying upon any privileged or confidential information as support for my
11 opinions.

12 **Q. Who are the key Ameren employees whose testimony and declarations**
13 **you reference?**

14 **A.** Steven Whitworth and David Boll. Mr. Whitworth leads Ameren
15 Missouri's Environmental Services Department and has done so since 2007. Schedule
16 JRH-D2 (Whitworth Declaration) ¶ 2. The Environmental Services Department had
17 responsibility for determining whether permits were required for the Rush Island Projects.
18 Whitworth Declaration ¶ 3. The Environmental Services Department did so through
19 collaborative discussion involving engineers in other departments who had knowledge
20 about and responsibility for the projects. Whitworth Declaration ¶¶ 3-6. David Boll, a
21 licensed professional engineer in Ameren Missouri's Environmental Project Engineering
22 Department, was one such individual. Mr. Boll's responsibilities included supervising the
23 work for the component replacement projects at issue at Rush Island and assessing the

1 impact component replacements were expected to have on unit operations. Schedule JRH-
2 D3 (Boll Declaration) ¶¶ 2-3. As their declarations describe, Messrs. Whitworth and Boll
3 have personal knowledge of the permitting decisions Ameren Missouri made concerning
4 the Rush Island Projects.

5 **Q. Can you identify the projects and applicability determinations that you**
6 **have been asked to evaluate?**

7 A. I have been asked to evaluate Ameren Missouri's NSR applicability
8 determinations for the Rush Island Projects.

9 **Q. What permitting determinations did Ameren Missouri make for those**
10 **projects?**

11 A. Ameren Missouri determined that it did not need to obtain NSR permits for
12 any of the Rush Island Projects.

13 **Q. Do you know the basis for those determinations?**

14 A. As I mentioned, I have reviewed a number of documents related to Ameren
15 Missouri's determinations, all of which I understand were produced in the Ameren
16 Missouri litigation in the U.S. District Court for the Eastern District of Missouri. As
17 reflected in these documents, the Company had three basic reasons for these
18 determinations:

- 19 • Under the applicable regulations in the Missouri SIP, as I read them and as they
20 had been interpreted by the Missouri Department of Natural Resources, an NSR
21 permit was not required unless a project would cause an increase in "potential
22 emissions" at a facility, and none of the Rush Island Projects would increase
23 potential emissions.

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1 • Under the 2002 NSR rules incorporated into the Missouri SIP, none of the Rush
2 Island Projects would be expected to cause an increase in actual emissions and
3 thus would not trigger NSR.

4 • Because these same types of projects were done routinely throughout the
5 industry, they were considered “routine maintenance, repair and replacement”,
6 which is explicitly exempt from NSR.

7 Whitworth Declaration ¶¶ 7-15.

8 **Q. Can you summarize your opinion regarding the reasonableness of the**
9 **permitting determinations made by Ameren Missouri for those projects?**

10 A. At the times when Ameren Missouri determined that it did not need NSR
11 permits for the Rush Island Projects, each of these was a valid reason for making this
12 determination. Based on the regulations, regulatory interpretations, and guidance
13 documents available at the time, and the state of the law as it existed then, if I had been
14 advising Ameren Missouri at the time, I would have advised the Company that it did not
15 need NSR permits for any of the projects.

16 Before the Rush Island Projects, many other companies that owned or operated
17 coal-fired power plants had done the same types of projects at their plants, and none of
18 them had ever applied for or been required to obtain an NSR permit for any of these
19 projects. Ameren Missouri was certainly not alone in believing that it did not need NSR
20 permits for the types of projects the Company undertook at Rush Island in 2007 and 2010,
21 and its belief was reasonable given what it knew or should have known.

1 **Q. Why do you say, if you had been advising Ameren Missouri “at the**
2 **time”?**

3 A. I understand that the question in this proceeding is whether Ameren
4 Missouri acted reasonably when it decided that it didn’t need NSR permits for projects
5 performed during the Unit 1 or and Unit 2 outages. In retrospect, it’s easy to criticize those
6 decisions in light of the protracted litigation that ultimately found that the Company should
7 have obtained NSR permits. But if you look at the regulatory and legal landscape at the
8 time that Ameren Missouri made its compliance decisions, those decisions were entirely
9 reasonable.

10 I’ve been dealing with NSR issues and power companies for more than 30 years as
11 either a government official or an attorney in private practice. Based on this experience, I
12 don’t think any other company in Ameren Missouri’s position would have made a different
13 decision based on the regulatory landscape and the state of the law that existed in 2005 –
14 2010.

15 **Q. You mention three reasons why Ameren Missouri decided that it didn’t**
16 **need NSR permits. Let us take them one at a time. The first reason was that none of**
17 **the projects would increase “potential emissions” at either of the Units. Can you**
18 **explain why this was reasonable?**

19 A. Earlier in this testimony, I explained in detail the Missouri NSR regulations
20 (which had been approved by EPA) and how the different provisions regarding
21 “modification” and “major modification” could be read to work together. This is certainly
22 how I would have interpreted these regulations before the court’s ruling in the Ameren
23 Missouri enforcement case. More importantly, this is also how the Missouri DNR

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1 understood and interpreted these regulations (its own regulations) at the time when Ameren
2 Missouri did the Rush Island Projects.

3 In summary, under the Missouri SIP rules, the understanding was that an
4 owner/operator didn't need to get any kind of construction permit, including an NSR
5 permit, for a project at an existing emission unit unless it would be a "modification" of the
6 unit; a project is a modification only if it will cause "an increase in potential emissions"
7 from the unit; and potential emissions are defined as "[t]he emission rate of any pollutant
8 at maximum design capacity." 10 CSR 10-6.020(2) (Nov. 30, 2006). Thus, the
9 understanding was that a project is a modification only if it will cause an increase in the
10 emission rate when the source is operating at its maximum design capacity. None of the
11 projects at issue in this case increased the emission rate of either Unit 1 or Unit 2 when it
12 was operating at its maximum design capacity. Boll Declaration ¶¶ 7-8. Because none of
13 the projects was a "modification," Ameren Missouri's understanding was that none of the
14 projects would trigger NSR for that reason alone. Whitworth Declaration ¶¶ 9, 13. This
15 was a reasonable understanding at the time.

16 In fact, MDNR shared this understanding. Testifying on behalf of the Department
17 in the Ameren Missouri litigation in the U.S. District Court for the Eastern District of
18 Missouri, a senior MDNR official explained how all the permitting programs in the
19 approved Missouri SIP were read together. These explanations are a bit dense for anyone
20 not steeped in the permitting world, but she explained what I have summarized above. She
21 mentioned a number of different types of "construction permits," which include NSR
22 permits, but she said that you don't need to worry about any of the these permits unless
23 you trigger the applicability provisions of Section 10 CSR 10-6.020(2), which I have

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1 quoted above. This provision says that a project at an existing unit is not a modification
2 unless it will increase the “potential emissions” of that unit. According to MDNR, if it’s
3 not a modification, you don’t need to get any of the state’s construction permits, including
4 an NSR permit.

5 To understand this testimony, you need to know that the requirements for different
6 types of construction permits are covered in sections 5–8 of the regulations, and NSR
7 permits are covered in sections 7 and 8. The Company’s attorney asked MDNR’s
8 designated witness:

9 So am I correct that the process that MDNR has employed for
10 applicability assessments and then related permitting is, step one,
11 you look at the definition of modification and determine if there’s a
12 physical or operation change that would cause an increase in
13 potential emissions . . . and then, step two, if the answer is yes, you
14 look to section 5, 6, 7, and 8 of the construction permitting rules to
15 determine what the permitting requirements would be for the
16 required permit, is that correct?

17 Moore Dep. at 87. She confirmed that yes, this is correct. In another part of her testimony,
18 when the attorney was asking a complicated question about a step in the NSR applicability
19 test, she answered:

20 Well, the simplest matter is to look at the potential emissions of the
21 project, and if that by itself does not trigger any permitting action,
22 you don’t need to [go to that step].

23 Moore Dep. at 82-83. The attorney then said: “So just to clarify, that if you have no
24 potential project emission increases, you never need to get to the step two” Moore
25 Dep. at 83. Again, she confirmed that this is correct.

26 This same MDNR official later discussed a formal applicability determination that
27 the Department made in 2006 when asked about the replacement of some large components
28 at another coal-fired power plant in Missouri, the Thomas Hill Plant. Moore Dep. at 100 –

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1 102. The company had asked whether a proposed project to replace two cyclone burners
2 at the plant at a cost of approximately \$25 million would trigger permitting requirements.
3 After the company responded to several information requests from MDNR officials,
4 MDNR sent a formal applicability determination letter to the company stating:

5 Since there will be no increase in the potential to emit, according to
6 the applicant, the change can not be considered a modification, per
7 Missouri State Rule. Therefore, since replacement of the cyclone
8 burners does not meet the definition of . . . modification, the
9 replacement is exempt from permitting requirements.

10 Letter dated July 21, 2006 from Kyra Moore, Missouri DNR Permits Section Chief, to
11 Todd A. Tolbert, Associated Electric Cooperative, Inc., attached as Schedule JRH-D4.

12 Further supporting the reasonableness of this understanding of the Missouri SIP is
13 the fact that other states had followed this same basic approach. As I mentioned above,
14 both Nevada and Connecticut had similar applicability provisions in their SIP-approved
15 NSR programs. In both cases, before the states considered whether there was a “major
16 modification” that would trigger NSR, they first determined whether there would be a
17 “modification,” which was only the case if a physical change to a unit would increase its
18 potential emissions. If not, an NSR permit was not required.

19 In 2015, Steven Whitworth, the Senior Director for Environmental Policy and
20 Analysis at Ameren Missouri, signed a sworn declaration on behalf of the Company
21 regarding the Company’s pre-construction evaluations of the Unit 1 and Unit 2 Projects.
22 After noting that he had worked in the Company’s Environmental Services Department for
23 over 16 years, he stated:

24 Based on our considerable experience with NSR permitting under
25 the Missouri SIP, and the language of the SIP, we understand that
26 such projects would not increase the unit’s annual rate of potential
27 emissions, and therefore did not constitute “modifications” under
28 the Missouri SIP. Accordingly, we determined that such Projects

1 would not trigger the application of the Missouri Construction
2 Permit Rule, meaning no construction permit was required.

3 Whitworth Decl. ¶¶ 9, 13. Ameren Missouri’s approach to the Missouri SIP was entirely
4 reasonable at the time. In fact, given that the state permitting agency had the same
5 understanding of these regulations, I do not believe that any environmental specialist or
6 lawyer at a power company would have reached a different conclusion.

7 **Q. You mentioned a second reason why Ameren Missouri determined that**
8 **it did not need NSR permits for the Unit 1 or Unit 2 Projects—that none of them**
9 **would be expected to cause an increase in actual annual emissions from Rush Island.**
10 **How does a company determine whether a particular project at a power plant will**
11 **cause an annual emission increase for purposes of NSR?**

12 A. As I explained in detail earlier, you have to start by determining your
13 baseline emissions. Under the 2002 NSR Reform Rule incorporated into the Missouri SIP,
14 power plants can select the highest total emissions during any consecutive 24-month period
15 in the five years leading up to the project and then divide that number by two to calculate
16 their annual “baseline” emissions.

17 When it comes to projecting future annual emissions (*i.e.*, what the annual
18 emissions will be after the project), the NSR rules are necessarily less prescriptive. They
19 simply say that the company, after taking a number of factors into account, must project
20 annual emissions for the plant for every 12-month period, on a rolling basis, for at least 5
21 years after the change. If a change will increase the capacity of the unit, then the company
22 must project future emissions for the plant on a 12-month rolling basis for 10 years after
23 the change. If the projected future annual emissions in any of the 12-month periods are
24 higher than the baseline emissions (*i.e.*, there is a projected increase in emissions over the

1 baseline), then the next step is to subtract the amount of the increase that (1) “could have
2 been accommodated during the baseline period” and (2) is also “unrelated to the particular
3 project, including any increased utilization due to product demand growth.” 40 CFR
4 52.21(b)(41)(ii)(c).

5 These regulations were understood as simply a more structured way of considering
6 whether a particular project could actually cause an emission increase. This approach
7 recognizes that emissions may go up after a project for reasons that have nothing to do with
8 the project itself, often because of “demand growth.” If there is more demand for electricity
9 in the future compared to the baseline period, the plant may be called upon to operate more
10 in the future to meet this demand (depending on the availability of other power plants in
11 the area that can also meet this demand). If the plant had enough excess capacity during
12 the baseline period to meet the increased demand, this was understood to mean that a
13 projected increase in emissions “could have been accommodated during the baseline
14 period” because the plant could have operated more to satisfy this demand even if the
15 project hadn’t happened. If, after subtracting the emissions that “could have been
16 accommodated” and are unrelated to the project, there is still a projected increase, then that
17 remaining projected increase may be understood to result from the project.

18 **Q. Do the rules require a company to do numerical calculations to show**
19 **that a project will not cause an emission increase?**

20 A. The 2002 version of the NSR rules incorporated into the Missouri SIP did
21 not require numerical calculations. Companies often relied on their knowledge of their
22 operations and market to make these assessments. In many cases, making these
23 assessments could be very easy. As long as the particular project will not increase the

1 capacity of a plant or result in a material change in its efficiency, a company can usually
2 determine that the expected increase in emissions is “unrelated to the particular project” as
3 long as the plant “could have accommodated” those emissions before the project.

4 **Q. Have you evaluated Ameren Missouri’s determinations that none of the**
5 **Rush Island Projects would cause an increase in actual annual emissions?**

6 A. Yes.

7 **Q. Were those determinations reasonable?**

8 A. Yes, they were. I have reviewed the transcripts of depositions and
9 testimony regarding this evaluation, and the best summary of Ameren Missouri’s approach
10 comes from Mr. Whitworth’s 2015 declaration, where he says the following:

11 In addition to assessing the applicability of the Missouri SIP and
12 whether the 2007 Projects constituted routine maintenance repair
13 and replacement, Ameren also assessed any impact of the Projects
14 on projected actual future emissions. We had experience with and
15 knowledge of the similar projects described above, and were
16 familiar with the Rush Island units’ operational characteristics. This
17 included our knowledge that Ameren’s coal-fired generating units
18 operate below their available capacity and thus have a large amount
19 of unused capacity to generate. Based on these and other
20 considerations derived from our experience, knowledge and
21 judgment, and based on the judgment of Ameren’s engineering
22 personnel, we in Environmental Services concluded that the 2007
23 Projects would not cause actual emissions to increase.

24 Whitworth Decl. ¶ 11. Ameren Missouri reached the same conclusion concerning the 2010
25 Projects. Whitworth Decl. ¶ 15. Ameren Missouri’s approach was consistent with what I
26 have seen from other companies, including companies in the power sector. If a particular
27 project or set of projects will not increase the capacity of a unit or result in a material
28 change in its efficiency, and the unit had plenty of excess capacity before the project, it is
29 easy to conclude that the project will not cause an emission increase. Boll Decl. ¶ 15.

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1 No matter how sophisticated the analysis, projections of future emissions at a power
2 plant are always uncertain because they depend on many factors that are outside the
3 company’s control, including the weather, actions of other companies, and overall
4 economic activity in the area served by the plant. Emissions of SO₂ from Rush Island varied
5 considerably from year to year both before and after the Rush Island Projects occurred.
6 Whitworth Declaration ¶¶ 30-33. If company experts know that, for technical reasons, a
7 particular project or set of projects will not have any impact on how often a unit will operate
8 or how much it will be able to produce (and therefore emit) in future years, they can
9 reasonably conclude that the project or set of projects will not cause any increase in
10 emissions without any calculations. That is the case here. Boll Declaration ¶¶ 7-19;
11 Whitworth Declaration ¶¶ 11, 15. In my opinion, the Company’s determination that the
12 Rush Island Projects would not cause an increase in actual annual emissions was
13 reasonable.

14 Based on my experience with the power sector, I think any other power company
15 would have made the same determination.¹

16 **Q. Finally, you mentioned that Ameren Missouri also relied on the RMRR**
17 **exclusion when it determined that it didn’t need NSR permits. Can you explain why**
18 **this was also reasonable?**

19 A. As I mentioned earlier, both the federal NSR regulations and the State’s
20 SIP-approved NSR regulations have an explicit NSR exemption for projects that qualify as
21 RMRR. NSR applies to an existing unit only if there is “a physical or operational change”

¹ I am also aware that Ameren Missouri performed some emissions calculations for the Unit 2 Projects after that work commenced. Whitworth Declaration ¶¶ 16-26. Although I am not relying on those calculations for my opinion that Ameren Missouri’s pre-project applicability determinations were reasonable, I conclude that Ameren Missouri’s post-project calculations for Unit 2 were reasonable as well.

Direct Testimony of
Jeffrey R. Holmstead

1 at the unit that results in a significant emission increase. Any type of maintenance, repair
2 or replacement project that qualifies as RMRR is explicitly excluded from the definition of
3 a physical or operational change.

4 All federal and state NSR programs have an exception or an exclusion from NSR
5 for routine maintenance, repair and replacement on existing units, and other permitting and
6 regulatory programs do as well. In my experience, whenever an industrial facility is doing
7 significant maintenance work during an outage, it will consider whether the work should
8 be considered RMRR. In the vast majority of cases, operators simply rely on their
9 experience with the ongoing maintenance of their facilities and their knowledge of
10 maintenance practices within the industry to determine whether particular projects should
11 be viewed as RMRR.

12 It is clear from the documents I have reviewed that, before undertaking the Rush
13 Island Projects, Ameren Missouri considered whether they qualified as RMRR. They were
14 aware of the maintenance, repair and replacement practices at the many different power
15 plants they operate, and of those across the industry as well. Again, I will quote from Mr.
16 Whitworth's declaration, where he made the following statement regarding both sets of
17 projects:

18 As explained in Mr. Boll's declaration, Ameren engineering
19 personnel had also determined that the [Unit 1 and 2] Projects were
20 routine in nature because, among other reasons, they were like-kind
21 replacements of existing components with new components that
22 were functionally equivalent. Ameren was aware that such
23 replacements were commonly performed throughout the industry. I
24 and my colleagues in Environmental Services knew that Ameren
25 had conducted dozens of similar component replacements at its
26 other generating units in prior years. Accordingly, I and my
27 colleagues in Environmental Services determined, prior to the [Unit
28 1 and 2] Projects, that Ameren's routine boiler component
29 replacements such as the [Unit 1 and 2] Projects constituted routine

1 maintenance repair and replacement activities that are excluded
2 from NSR permitting under the Missouri SIP.

3 Whitworth Decl. ¶¶10, 14. See also Boll Decl. ¶ 14. Ameren Missouri’s determinations
4 that the Rush Island Projects were RMRR were certainly reasonable at the time they were
5 made.

6 By that time, many such projects (the replacement of boiler components such as
7 reheaters, economizers, air preheaters, and boiler tubes) had been made throughout the
8 industry. This is clear from a 2000 report titled *Routine Maintenance of Electric*
9 *Generating Stations* that was issued by the Tennessee Valley Authority (“TVA”). The
10 TVA report was based on an industry-wide survey and was explicitly noticed in the *Federal*
11 *Register*. 65 Fed. Reg. 35154 (June 1, 2000). It reviews TVA and general industry
12 experience with regard to a number of component replacement projects that were the same
13 or similar to the Rush Island Projects and found that several hundred of them had been
14 done on coal-fired power plants prior to 1999. TVA itself had done a number of them, but
15 neither TVA (the federal government’s public utility) nor anyone else had ever applied for
16 an NSR permit for any such project or group of projects. Even considering all the Rush
17 Island Projects together, they were much less extensive than the “WEPCO type” changes
18 that EPA had said were unprecedented and the only type of component replacement project
19 that would trigger NSR.

20 Thus, it was reasonable for Ameren Missouri to rely on the RMRR exclusion, and
21 EPA’s statements concerning its scope, in determining that the company was not required
22 to seek NSR permits for any of the Rush Island Projects. At the time Ameren Missouri
23 made these determinations, I don’t believe that any power company in the country would

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1 have taken a different position. Even today, I believe that many power companies would
2 make the same determination for such projects.

3 **Q. Does this conclude your direct testimony?**

4 **A.** Yes, it does.

DIRECT TESTIMONY OF JEFFREY R. HOLMSTEAD
CASE NO. ER-2022-0337
SCHEDULES

Index

| Schedule | Description |
|-----------------|---|
| JRH-D1 | Curriculum Vitae of Jeffrey R. Holmstead |
| JRH-D2 | U.S. v. Ameren Missouri, ECF 568-1, Declaration of Steven Whitworth (without exhibits)* |
| JRH-D3 | U.S. v. Ameren Missouri, ECF 568-4, Declaration David Boll (without exhibits)* |
| JRD-D4 | EXCERPTED Exhibit 7 (Applicability Determination Request) to Videotaped 30(b)(6) Deposition of Kyra Moore, <u>United States v. Ameren Missouri</u> , (Sept. 18, 2013) |

*As noted on the face of Schedule JRH-D2 and Schedule JRH-D3, these declarations were redacted pursuant to the protective order, governing the use of confidential business information, entered by the U.S. District Court for the Eastern District of Missouri. The versions of these declarations provided here are the redacted versions, without exhibits, filed in the District Court.

JEFFREY R. HOLMSTEAD

2001 M Street, NW, Suite 500 | Washington, D.C. 20036 | 202.828.5852 |
jeff.holmstead@bracewellllaw.com

Professional Experience

Bracewell LLP, Washington, D.C. Office 2006-Present

Partner and Head of the Environmental Strategies Group

The Environmental Strategies Group (ESG) is a multi-disciplinary group that includes environmental and energy attorneys, public policy advocates, and strategic communications experts – many of whom have had high-level government experience. As head of the ESG, Mr. Holmstead represents companies, business groups, and not-for-profit organizations on a wide range of environmental and energy-related issues related to the Clean Air Act.

United States Environmental Protection Agency 2001-2005

Assistant Administrator for Air and Radiation

Appointed by President George W. Bush and confirmed by the U.S. Senate to oversee all regulatory and permitting programs created under the Clean Air Act. During his tenure at EPA, Mr. Holmstead was the architect of several of the Agency’s most important initiatives, including the Clean Air Interstate Rule, the Clean Air Diesel Rule, the Mercury Rule for power plants, and the reform of the New Source Review program. He also oversaw the development of the Bush Administration’s Clear Skies Legislation and key parts of its Global Climate Change Initiative.

Latham & Watkins, Washington, D.C. Office 1993-2001

Associate and then Partner

As a member of the firm’s Environmental Group, Mr. Holmstead represented a wide variety of companies and trade associations dealing with issues arising under several environmental statutes. Much of his work involved the Clean Air Act and, in particular, regulatory issues arising from the 1990 Amendments to the Clean Air Act.

The White House 1989-1993

Associate Counsel to President George H.W. Bush

Served on the White House Staff as a member of the White House Counsel’s Office. In this capacity, Mr. Holmstead was involved in discussions that led to passage of the Clean Air Act Amendments of 1990. After the Amendments were adopted, he was involved in the interagency review process for all major EPA rules arising under the Clean Air Act.

Davis, Polk, and Wardwell LLP, Washington, D.C. Office 1988-1989

Associate

Worked on securities offerings and advised companies on a range of regulatory issues.

U.S. Court of Appeals for the District of Columbia Circuit 1987-1988

Law Clerk to Judge Douglas H. Ginsburg

Education

J.D., Yale Law School, 1987

B.A., *summa cum laude*, Brigham Young University, 1984

Noteworthy

- Chambers & Partners, *Chambers USA*, Climate Change, 2010-present; Environment, 2008-present
- Woodward/White, Inc., *Best Lawyers*, Environmental Law, 2008-present
- *US Legal 500*, Environment: Litigation, 2012

Congressional Testimony by Jeffrey R. Holmstead

- U.S. House Committee on Energy and Commerce
Subcommittee on Environment
Hearing entitled "Legislation Addressing New Source Review Permitting Reform" May 16, 2018
- U.S. House Committee on Energy and Commerce
Subcommittee on Environment
Hearing entitled "New Source Review Permitting Challenges for Manufacturing and Infrastructure" February 14, 2018
- U.S. House Committee on Science, Space and Technology
Hearing entitled "Making EPA Great Again" February 7, 2017
- U.S. House Committee on Science, Space and Technology
Hearing entitled "EPA's 2015 Ozone Standard: Concerns Over Science and Implementation" October 22, 2015
- U.S. Senate Committee on Environment and Public Works
Hearing entitled "Road to Paris: Examining the President's International Climate Agenda and Implications for Domestic Environmental Policy" July 8, 2015
- U.S. House Committee on Science, Space and Technology
Hearing entitled "EPA's Carbon Plan: Failure by Design" July 30, 2014
- U.S. House Committee on Science, Space, and Technology
Subcommittee on Environment
Hearing entitled "Background Check: Achievability of New Ozone Standards" June 12, 2013
- U.S. House Energy and Commerce Committee
Subcommittee on Energy and Power
Hearing entitled "Implications of EPA's Proposed National Ambient Air Quality Standards (NAAQS) for Fine Particles (PM2.5)" June 28, 2012
- U.S. Senate Committee on Environment & Public Works
Subcommittee on Clean Air and Nuclear Safety
Hearing entitled "Review of Mercury Pollution's Impacts to Public Health and the Environment" April 17, 2012
- U.S. House Judiciary Committee
Subcommittee on Courts, Commercial and Administrative Law
Hearing entitled "Cost-Justifying Regulations: Protecting Jobs and the Economy by Presidential and Judicial Review of Costs and Benefits" May 4, 2011
- U.S. House Select Committee on Energy Independence & Global Warming Dec. 11, 2008

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Hearing regarding the Administrative Procedure Act and “midnight” regulations

- U.S. House Committee on Energy Independence and Global Warming June 26, 2008
Hearing entitled “\$4 Gasoline and Fuel Economy: Auto Industry at a Crossroads”
- U.S. Senate Committee on Environment and Public Works Jan. 24, 2008
Hearing entitled “Oversight of EPA’s Decision to Deny California Waiver Request”
- U.S. House Committee on Energy and Commerce May 26, 2005
Subcommittee on Energy and Air Quality
Hearing on the President’s Clear Skies Act, and the reduction of emissions of sulfur dioxide (SO₂), nitrogen oxides (NO_x) and mercury from power plants
- U.S. Senate Committee on Environment and Public Works March 20, 2003
Subcommittee on Clean Air, Climate Change, and Nuclear Safety
Hearing on alternative fuels and fuel additives
- U.S. House Committee on Energy and Commerce March 2, 2005
Subcommittee on Energy and Air Quality
Hearing entitled “Clean Air Act Transportation Conformity Provisions Contained in H.R.3, Transportation Equity Act: A Legacy for Users”
- U.S. House Committee on Health, Education, Labor, and Pensions Sept. 3, 2002
Subcommittee on Public Health
Hearings concerning proposed improvements to the New Source Review (NSR) program under the Clean Air Act
- U.S. Senate Committee on Environment and Public Works July 30, 2002
Hearing on the Congestion Mitigation and Air Quality Improvement program (CMAQ)
- U.S. Senate Committee on Environment and Public Works July 16, 2002
U.S. Senate Committee on the Judiciary
Joint hearing on New Source Review policy, regulations, and enforcement activities
- Senate Committee on Energy and Natural Resources May 23, 2002
Hearing concerning EPA’s role in setting public health and environmental radiation protection standards for the proposed spent nuclear fuel and high-level radioactive waste repository at Yucca Mountain, Nevada
- U.S. House Committee on Energy and Commerce May 1, 2002
Subcommittee on Energy and Air Quality
Hearing entitled “Accomplishments of the Clean Air Act, as amended by the Clean Air Act Amendments of 1990”
- U.S. House Committee on Energy and Commerce April 18, 2002
Subcommittee on Energy and Air Quality

Hearing entitled “A Review of the President’s Recommendation to Develop a Nuclear Waste Repository at Yucca Mountain, Nevada”

U.S. Senate Committee on Environment and Public Works

Nov. 1, 2001

Hearing on S. 556 on its impact on the environment and the economy and any improvements or amendments that should be made to the legislation

**UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION**

UNITED STATES OF AMERICA,)

Plaintiff,)

v.)

AMEREN MISSOURI,)

Defendant.)

**Case No. 4:11-CV-00077-RWS
Judge Rodney W. Sippel**

AMEREN MISSOURI'S SUMMARY JUDGMENT MOTIONS

EXHIBIT A1

PORTIONS REDACTED PURSUANT TO ECF # 90

PART 1 OF 3

JRH-D2

**UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION**

| | | |
|----------------------------------|---|--|
| UNITED STATES OF AMERICA, |) | |
| |) | |
| Plaintiff, |) | |
| |) | |
| v. |) | |
| |) | |
| AMEREN MISSOURI, |) | |
| |) | |
| Defendant. |) | |
| |) | |

Case No. 4:11-CV-00077-RWS

Judge Rodney W. Sippel

DECLARATION OF STEVEN WHITWORTH

I, Steven Whitworth, am over 18 years of age and make the following declaration pursuant to 18 U.S.C. § 1746:

1. I make this declaration on behalf of Ameren Missouri (“Ameren”) based on my personal knowledge, and the records of Ameren or information available through employees of Ameren. I am prepared to testify to the following facts if called as a witness.

2. I am employed by Ameren Services Company, which provides services to Ameren Corporation’s operating companies, including Ameren Missouri (which I will generally refer to below as “Ameren”). I have worked in Ameren’s Environmental Services Department for over 16 years, and since 2007 I have managed and directed that Department. My title is Senior Director, Environmental Policy and Analysis. I am familiar with Ameren’s emissions assessments for the 2007 and 2010 Projects at issue in this case.

Assessment of Projects for Construction Permitting Applicability

3. Ameren’s Environmental Services Department (“Environmental Services”) plays a lead role in evaluating whether environmental permits are required for activities Ameren

undertakes, including whether major New Source Review (“NSR”) or other construction permits are required under the Missouri State Implementation Plan (“SIP”) Construction Permitting Rule, 10 C.S.R. 10-6.060. Typically, we reach a consensus decision within Environmental Services on permit applicability through collaborative discussion.

4. To assess the nature of a project and to determine whether it should be considered for air construction permitting, Environmental Services typically works in conjunction with Ameren engineering personnel in the Project Engineering and Performance Engineering departments. We will also consult other Ameren departments (for example, Corporate Planning) as needed.

5. Environmental Services staff have considerable knowledge and experience with assessing permit applicability regarding all manner of projects at Ameren, including component replacements at Ameren’s power plants, like Rush Island. We used that prior experience with similar activities in assessing any emission impact of the 2007 and 2010 Projects.

6. Environmental Services also relies on the subject matter expertise of our engineering colleagues to identify projects that have the potential, from an engineering point of view, to result in emissions increases, due to their nature and scope. Ameren had conducted dozens of similar boiler component replacement projects at its other plants prior to performing the 2007 and 2010 Projects. Our experience with and knowledge gained from those similar projects informed our decision-making and analysis with respect to the 2007 and 2010 Projects.

7. Ameren assesses the impact that a project is expected to have on unit operations well before beginning construction, as part of its project planning and justification processes. Consistent with normal practice, Ameren assessed the expected impact of the 2007 and 2010 Projects before beginning construction of those projects.

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Ameren's Emissions Assessment for the 2007 Projects at Rush Island Unit 1

8. Ameren conducted a planned unit outage at Rush Island Unit 1 from approximately February to May 2007. During this outage, I understand that Ameren performed nearly 100 discrete projects. I understand that just four of those projects are at issue in this case: the replacements of the reheater, economizer, lower slope and air preheater components (the "2007 Projects"). While Ameren made emissions assessments with respect to all of the activities taking place during the 2007 Outage as a whole, to simplify the following discussion, I will refer to the 2007 Projects.

9. I understand from David Boll, currently Ameren's Consulting Engineer in Ameren's Environmental Project Engineering Department, that before the 2007 Outage, Ameren engineering personnel assessed the nature and scope of the 2007 Projects and the other projects planned to be undertaken during the 2007 Outage, and concluded that none of those projects would increase the unit's maximum annual rated design capacity given continuous year-round operations. Based on our considerable experience with NSR permitting under the Missouri SIP, and the language of the SIP, we understand that such projects would not increase the unit's annual rate of potential emissions, and therefore did not constitute "modifications" under the Missouri SIP. Accordingly, we determined that such Projects would not trigger the application of the Missouri Construction Permit Rule, meaning no construction permit was required.

10. As explained in Mr. Boll's declaration, Ameren engineering personnel had also determined that the 2007 Projects were routine in nature because, among other reasons, they were like-kind replacements of existing components with new components that were functionally equivalent. Ameren was aware that such replacements were commonly performed throughout the industry. I and my colleagues in Environmental Services knew that Ameren had conducted

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dozens of similar component replacements at its other generating units in prior years. Accordingly, I and my colleagues in Environmental Services determined, prior to the 2007 Projects, that Ameren's routine boiler component replacements such as the 2007 Projects constituted routine maintenance repair and replacement activities that are excluded from NSR permitting under the Missouri SIP.

11. In addition to assessing the applicability of the Missouri SIP and whether the 2007 Projects constituted routine maintenance repair and replacement, Ameren also assessed any impact of the Projects on projected actual future emissions. We had experience with and knowledge of the similar projects described above, and were familiar with the Rush Island units' operational characteristics. This included our knowledge that Ameren's coal-fired generating units operate below their available capacity and thus have a large amount of unused capacity to generate. Based on these and other considerations derived from our experience, knowledge and judgment, and based on the judgment of Ameren's engineering personnel, we in Environmental Services concluded that the 2007 Projects would not cause actual emissions to increase.

Ameren's Emissions Assessment for the 2010 Projects at Rush Island Unit 2

12. Ameren conducted a planned unit outage at Rush Island Unit 2 from approximately January to April 2010. During this outage, I understand that Ameren performed over 100 discrete projects. I understand that only 3 of these projects are at issue: the replacements of the reheater, economizer, and air preheater components of Rush Island Unit 2 (the "2010 Projects"). While Ameren made emissions assessments with respect to all of the activities taking place during the 2010 Outage as a whole, to simplify the following discussion, I will refer only to the 2010 Projects.

13. I understand from Mr. Boll that before the 2010 Outage, Ameren engineering personnel assessed the nature and scope of the 2010 Projects and the other projects planned to be

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undertaken during the 2010 Outage, and concluded that none of those projects would increase the unit's maximum annual rated design capacity given continuous year-round operations. Based on our considerable experience with NSR permitting under the Missouri SIP, and the language of the SIP, we in Environmental Services understand that such projects would not increase the unit's annual rate of potential emissions, and therefore did not constitute "modifications" under the Missouri SIP. Accordingly, we determined that such Projects would not trigger the application of the Missouri Construction Permit Rule, meaning no construction permit was required.

14. As explained in Mr. Boll's declaration, Ameren engineering personnel had also determined that the 2010 Projects were routine in nature because, among other reasons, they were like-kind replacements of existing components with new components that were functionally equivalent. Ameren was aware that such replacements were commonly performed throughout the industry. I and my colleagues in Environmental Services knew that Ameren had conducted dozens of similar component replacements at its other generating units in prior years. Accordingly, I and my colleagues in Environmental Services determined, prior to the 2010 Projects, that Ameren's routine boiler component replacements such as the 2010 Projects constituted routine maintenance repair and replacement activities that are excluded from NSR permitting under the Missouri SIP.

15. In addition to assessing the applicability of the Missouri SIP and whether the 2010 Projects constituted routine maintenance repair and replacement, Ameren also assessed any impact of the Projects on projected actual future emissions. We had experience with and knowledge of the similar projects described above, and were familiar with the Rush Island units' operational characteristics. This included our knowledge that Ameren's coal-fired generating

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units operate below their available capacity and thus have a large amount of unused capacity to generate. Based on these and other considerations derived from our experience, knowledge and judgment, and based on the judgment of Ameren's engineering personnel, we in Environmental Services concluded that the 2010 Projects would not cause actual emissions to increase.

16. In addition to the foregoing assessment of actual emissions, Ameren also documented an assessment of whether there was a reasonable possibility, within the meaning of the relevant rules, that the 2010 Projects would increase emissions from the unit. The Missouri state permitting rules had changed in late 2009, requiring Missouri operators to perform in certain instances a numerical calculation of emissions, a requirement that had not applied under either the applicable state or federal regulations prior to that. While we believed (see above) that no construction permit of any kind was required under the Missouri Construction Permitting Rule, and that the 2010 Projects were excluded from New Source Review permitting because they constituted routine maintenance repair and replacement, we nonetheless prepared a numerical calculation out of an abundance of caution.

17. To determine whether there was a reasonable possibility of an emissions increase from the 2010 Outage, Environmental Services prepared a numerical emissions projection. A true and correct copy of the results of that projection, titled "Rush Island Unit 2 – Spring 2010 Outage – Reasonable Possibility Analysis Summary" is attached hereto as Attachment 1. (The document attached as Attachment 1 is the summary or conclusion page of a much larger document containing all the details of Ameren's analysis. Ameren produced the entire analysis during discovery in this case, but given its volume has not attached it here. Ameren stands ready to provide it to the Court upon request.)

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18. Pursuant to 40 C.F.R. 52.21(b)(48) (as incorporated by reference in the Missouri SIP at 10 C.S.R. 10-6.060(8)), Ameren first calculated Unit 2's "baseline actual emissions" rate by taking the average annual rate from the 24-month period of April 2005 through March 2007. That rate was 14,288 tons per year.

19. Pursuant to 40 C.F.R. 52.21(b)(41)(i) (incorporated by reference in the Missouri SIP at 10 C.S.R. 10-6.060(8)), Ameren then determined Unit 2's "maximum annual rate" of future actual emissions in the five years following the date Unit 2 would resume regular operation after the 2010 Outage. That maximum annual rate was 16,818.88 tons per year. In Attachment 1, this is shown under the column labeled "Projected Actual Emissions (tons/year)." This calculation of emissions following the Projects did not yet account for causation, which the NSR regulations require be accounted for through application of the "capable of accommodating" provision.

20. We did not believe that any relevant fugitive emissions were quantifiable, and so did not project them according to 40 C.F.R. 52.21(b)(41)(ii)(b) (incorporated by reference in the Missouri SIP at 10 C.S.R. 10-6.060(8)). Emissions associated with startups, shutdowns and malfunctions were included in the projection of the maximum annual rate of projected future emissions following the 2010 Outage.

21. Finally, as required pursuant to the "capable of accommodating" provision (sometimes called the demand growth provision), 40 C.F.R. 52.21(b)(41)(ii)(c) (as incorporated by reference in the Missouri SIP at 10 C.S.R. 10-6.060(8)), Ameren determined the amount of emissions following the 2010 Projects that was unrelated to the 2010 Projects. We initially determined the amount of emissions that Unit 2 could have accommodated during the baseline period above and beyond those it actually emitted during the baseline period. That amount was

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3,275.11 tons per year. In Attachment 1, this is shown under the column labeled “Capable of Accommodating Emissions (tons/year).”

22. Ameren determined that additional amount of SO₂ emissions (3,275 tons per year) was unrelated to the Projects because it could have been emitted during the baseline period and was related to: (a) increased utilization due to increased market demand, up to a level not exceeding the unused capacity that actually was available during the baseline period; and/or (b) normal variations in hourly emissions rates due to a combination of factors unrelated to the 2010 Projects, none of which were expected to affect hourly emissions rates.

23. To determine the amount of emissions (if any) following the Projects that were related to the Projects, Ameren then excluded (*i.e.*, subtracted) a portion (2,531.15 tons per year, “Excluded Emissions” on Attachment 1) of the unrelated SO₂ emissions from the difference between baseline emissions (14,287.73 tons per year) and the emissions following the Projects (16,818.88 tons per year).

24. The result of this calculation was zero, and is shown as the “Net Change” on Attachment 1. Stated mathematically: $16,818.88 \text{ minus } 14,287.73 \text{ minus } 2,531.15 \text{ equals } 0.00$, the emissions related to the Project. (We did not subtract all 3,275.11 tons per year of unrelated emissions because that would have resulted in a negative number.)

25. Because, after following the requirements of the regulation, any amount of projected SO₂ emission increase related to the 2010 Projects was less than the 40-ton significance threshold for SO₂, Ameren determined that the 2010 Projects (and the 2010 Outage as a whole) would not cause a significant increase in emissions of SO₂.

26. Pursuant to 40 C.F.R. 52.21(b)(41)(ii)(a) (incorporated by reference in the Missouri SIP at 10 C.S.R. 10-6.060(8)), when determining the annual rate of “projected actual

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emissions,” (as defined under 40 C.F.R. 52.21(b)(41)(i), Ameren considered all relevant information. In addition to the considered judgment and expertise of Environmental Services, we relied (as described above) on the judgment and expertise of Ameren’s engineering personnel, performance engineering personnel, and Corporate Planning department, among others. Ameren considered all relevant information regarding Unit 2’s historical operational data, Unit 2’s expected business activity and Ameren’s highest projections of business activity. Ameren also considered the amount of unused, but available generating capacity that was available to it during the baseline period, and which Unit 2 could have utilized had the market called upon it to do so. Ameren also considered the normal variations in hourly emission rates that occur during the normal operations of Unit 2.

27. Ameren retained records of this calculation. Since well before the Projects took place, Ameren reports the SO₂ emissions from both Rush Island units to EPA as part of its submission of CEMS data (see below).

Rush Island Emissions and Generation Over Time

28. Ameren’s Environmental Services Department plays a role in monitoring the emissions of each of Ameren’s plants, including Rush Island.

29. Rush Island’s Continuous Emissions Monitor Systems (CEMS) measure and record emissions data on a continuous basis during Rush Island’s operations. Ameren gathers that data and reports it to EPA. EPA keeps this data in databases and publishes it on the internet, where it can be accessed by the general public. The CEMS data contains multiple data points in addition to emissions, including gross generation. I am familiar with CEMS Data and use it routinely in carrying out my job responsibilities.

30. I reviewed the CEMS data for SO₂ emissions, NO_x emissions, and gross generation over time. As the below table demonstrates, compared to 1990 levels, Rush Island’s

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annual emissions of SO₂ in 2014 were just 39% of their 1990 levels, a decrease of over 27,500 tons per year. That decrease came about even though Rush Island’s annual generation of electricity has increased and is now 152% of their 1990 levels, an increase of over 3 gigawatt-hours per year. Likewise, Rush Island’s emissions of NO_x are at just 28% of their 1995 levels, a decrease of nearly 9,000 tons per year.

Rush Island Generation and Emissions 1990-2014

| Year | Unit 1 Generation (MWH) | Unit 1 SO ₂ (TPY) | Unit 1 NO _x (TPY) | Unit 2 Generation (MWH) | Unit 2 SO ₂ (TPY) | Unit 2 NO _x (TPY) |
|------|-------------------------------|------------------------------------|------------------------------------|-------------------------------|------------------------------------|------------------------------------|
| 1990 | 2,786 | 21,343 | - | 3,101 | 23,609 | - |
| 1995 | 3,614 | 21,412 | 4,593 | 2,821 | 22,209 | 7,734 |
| 1996 | 3,401 | 13,225 | 4,077 | 3,917 | 14,044 | 3,922 |
| 1997 | 3,735 | 13,484 | 3,826 | 3,222 | 11,659 | 3,032 |
| 1998 | 3,936 | 13,485 | 3,396 | 4,281 | 13,924 | 3,710 |
| 1999 | 3,721 | 12,653 | 2,711 | 4,276 | 14,543 | 2,981 |
| 2000 | 4,228 | 13,643 | 2,801 | 4,107 | 13,257 | 2,589 |
| 2001 | 3,169 | 8,963 | 1,824 | 3,794 | 10,912 | 2,295 |
| 2002 | 4,426 | 12,744 | 2,092 | 3,506 | 10,511 | 1,900 |
| 2003 | 4,565 | 13,127 | 1,928 | 3,797 | 11,866 | 1,856 |
| 2004 | 3,916 | 11,725 | 1,602 | 3,995 | 11,193 | 1,665 |
| 2005 | 4,467 | 14,070 | 1,971 | 4,952 | 14,315 | 2,098 |
| 2006 | 4,613 | 14,584 | 1,991 | 4,638 | 14,090 | 1,976 |
| 2007 | 2,936 | 9,126 | 1,268 | 4,484 | 13,336 | 2,019 |
| 2008 | 4,794 | 15,492 | 2,086 | 4,456 | 14,102 | 2,106 |
| 2009 | 4,484 | 14,754 | 1,927 | 4,000 | 13,573 | 1,934 |
| 2010 | 4,506 | 14,964 | 1,935 | 3,360 | 11,103 | 1,449 |
| 2011 | 3,802 | 12,272 | 1,587 | 4,853 | 15,764 | 1,853 |
| 2012 | 4,455 | 10,642 | 1,549 | 4,097 | 9,780 | 1,405 |
| 2013 | 4,359 | 9,595 | 1,525 | 4,581 | 9,992 | 1,542 |
| 2014 | 4,161 | 8,846 | 1,456 | 4,171 | 8,598 | 1,394 |

Rush Island Emissions Variations Over Time

31. The amount of SO₂ emitted at Rush Island varies significantly from year to year. In my experience, such fluctuations are normal at coal-fired power plants and are caused by a variety of factors including variations in market demand. I have reviewed the emissions data for Rush Island for the decade from 1996 to 2006. I then determined the changes in emissions from year-to-year. Below is an accurate summary of the amount of SO₂ emitted at Rush Island from 1996 to 2006.

Rush Island SO₂ Emissions Variations Over Time

| | Unit 1 | | Unit 2 | |
|------|---------------------------|---------------------------|---------------------------|---------------------------|
| Year | SO ₂ Emissions | Change from previous year | SO ₂ Emissions | Change from previous year |
| 1996 | 13,225 | -- | 14,044 | -- |
| 1997 | 13,484 | 259 | 11,659 | -2,385 |
| 1998 | 13,485 | 1 | 13,924 | 2,265 |
| 1999 | 12,653 | -832 | 14,543 | 619 |
| 2000 | 13,643 | 990 | 13,257 | -1,286 |
| 2001 | 8,963 | -4,680 | 10,912 | -2,345 |
| 2002 | 12,744 | 3,781 | 10,511 | -401 |
| 2003 | 13,127 | 383 | 11,866 | 1,355 |
| 2004 | 11,725 | -1,402 | 11,193 | -673 |
| 2005 | 14,070 | 2,345 | 14,315 | 3,122 |
| 2006 | 14,584 | 514 | 14,090 | -225 |

32. I reviewed the SO₂ emissions data for Rush Island Unit 1 for 2007 to 2014. I have provided a chart of the SO₂ emissions by year for the unit, below. The data for 2007 only includes a partial year of service because the plant was not operating during the Spring 2007 outage. Annual emissions are now about 5,000 tons per year below their averages before the 2007 Projects.

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Unit 1 SO₂ Emissions After the 2007 Projects

| Year | SO₂ (TPY) |
|-------------|---------------------------------|
| 2007 | 9,126 |
| 2008 | 15,492 |
| 2009 | 14,754 |
| 2010 | 14,964 |
| 2011 | 12,272 |
| 2012 | 10,642 |
| 2013 | 9,595 |
| 2014 | 8,846 |

33. I reviewed the SO₂ emissions data for Rush Island Unit 2 for 2010 to 2014. I have provided a chart of the SO₂ emissions by year for the unit, below. The data for 2010 only includes a partial year of service because the plant was not operating during the Spring 2010 outage. As with Unit 1, annual emissions are now about 5,000 tons per year below their averages before the 2010 Projects.

Unit 2 SO₂ Emissions After the 2010 Projects

| Year | SO₂ (TPY) |
|-------------|---------------------------------|
| 2010 | 11,103 |
| 2011 | 15,764 |
| 2012 | 9,780 |
| 2013 | 9,992 |
| 2014 | 8,598 |

Title V

34. Environmental Services is responsible for obtaining and securing the renewal of Title V Permits for the Rush Island plant. The applicable permit for the Rush Island units at the

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time of the 2007 and 2010 outages, Operating Permit No. OP2000061, was issued on May 18, 2000. A true and correct copy of the Title V permit is attached hereto as Attachment 2 (AM-02511339).

35. It is my understanding that before issuing a Title V Permit, the Missouri Department of Natural Resources provides the draft permit to EPA for comment or objection. EPA did not make any objection to Ameren's Title V operating permit before it was issued on May 18, 2000.

36. Generally, Title V permits have a 5-year term length. Although Title V permits must be renewed before they expire, because of permitting delays, permit renewals often take years to complete.

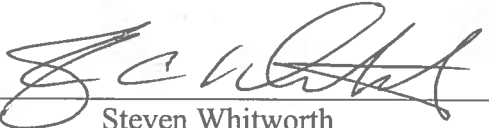
37. On or about November 18, 2004, Ameren filed an application to renew the May 18, 2000 Title V permit (Permit No. OP2000061).

38. On or about May 29, 2010, the Missouri Department of Natural Resources provided EPA a copy of the draft Rush Island Title V Permit. EPA did not object to the permit renewal.

39. On August 30, 2010, MDNR renewed Ameren's Title V Permit for the Rush Island Units, Operating Permit No. OP2010-047. A true and correct copy of the Title V permit is attached hereto as Attachment 3 (AM-00424093).

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 23, 2015



Steven Whitworth

JRH-D2

**UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION**

UNITED STATES OF AMERICA,)
)
 Plaintiff,)
)
 v.)
)
AMEREN MISSOURI,)
)
 Defendant.)

**Case No. 4:11-CV-00077-RWS
Judge Rodney W. Sippel**

AMEREN MISSOURI'S SUMMARY JUDGMENT MOTIONS

EXHIBIT A2

PORTIONS REDACTED PURSUANT TO ECF # 90

**UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION**

UNITED STATES OF AMERICA,)
)
 Plaintiff,)
)
 v.)
)
AMEREN MISSOURI,)
)
 Defendant.)

Case No. 4:11-CV-00077-RWS

Judge Rodney W. Sippel

DECLARATION OF DAVID BOLL

I, David Boll, am over 18 years of age and make the following declaration pursuant to 18 U.S.C. § 1746:

1. I make this declaration on behalf of Ameren Missouri (“Ameren”) based on my personal knowledge, and the records of Ameren or information available through employees of Ameren. I am prepared to testify to the following facts if called as a witness.

2. I have been employed by Ameren since 1981 and I currently hold the position of Consulting Engineer in Ameren’s Environmental Project Engineering Department. I received a B.S. in Mechanical Engineering from Washington University in St. Louis in 1981. I am a licensed Professional Engineer in the States of Missouri and Illinois.

3. My responsibilities during the time relevant to this case included justifying capital projects; preparing documents associated with such justifications such as project justification and work order documents; assessing the impact of component replacements on the performance and operations of the unit; preparing requests for proposal to be let out for bids; and supervising the construction of capital projects, including the component replacements at issue in this case.

The Projects

4. Ameren replaced portions of the reheater, economizer, lower slope and air preheater components of Rush Island Unit 1 (the “2007 Projects”) during the outage that took place from approximately February to May, 2007.

5. Ameren replaced portions of the reheater, economizer, and air preheater components of Rush Island Unit 2 (the “2010 Projects”) during the outage that took place from approximately January to April, 2010.

The Effect of the Projects on the Units’ Maximum Design Capacity

6. I am familiar with the projects to replace the reheater, economizer, lower slope and air heater components that occurred during Ameren’s planned unit outage at Rush Island Unit 1 from approximately February to May 2007 (the “2007 Projects”). I am also familiar with the projects to replace the reheater, economizer and air heater components that occurred during Ameren’s planned unit outage at Rush Island Unit 2 from approximately January to April 2010 (the “2010 Projects”).

7. The nature of these component replacement projects is such that they would not reasonably be expected to, and Ameren did not expect them to, increase the Unit’s maximum design capacity or maximum annual-rated capacity assuming continuous year-round operation (or, as the concept is expressed in the electric power industry, the Unit’s “maximum continuous rating.”) Nor would they be expected to increase the Unit’s designed steam flow rating or designed heat input capacity.

8. I have reviewed the actual effects of the Projects, and they did not actually increase the Units’ maximum design capacity, maximum annual-rated capacity assuming

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continuous year-round operation, or maximum continuous rating. They did not increase the Unit's designed steam flow rating or designed heat input capacity.

The Scope of the 2007 and 2010 Outages

9. Ameren conducted a planned unit outage at Rush Island Unit 1 from approximately February to May 2007 (the "2007 Outage"). During such outages, Ameren attempts to schedule as many activities as possible to be completed, in order to minimize overall unit downtime, and because such outages are generally planned to occur only once every six years. During the 2007 Outage, Ameren conducted 93 discrete maintenance, repair and replacement projects at Unit 1. Some of these other projects are of the same size and scope as the Projects at issue. Ameren generally prepares a Post Outage Report detailing the work that is performed during an outage. A true and correct copy of the 2007 Unit 1 Post Outage Report is attached hereto as Attachment 1.

10. Of the 93 projects conducted during the 2007 Outage, I understand that only 4 are at issue in this case: the replacement of the reheater, economizer, lower slope and air heater components. Moreover, in addition to these 93 projects, during the same 2007 Outage, Ameren performed innumerable tasks as part of the boiler overhaul, all designed to improve the long-term reliability, availability, and efficiency of the boiler. These tasks are not captured in detail in the Post Outage Report.

11. Ameren conducted a planned unit outage at Rush Island Unit 2 from approximately January to April 2010 (the "2010 Outage"). During such outages, Ameren attempts to schedule as many activities as possible to be completed, in order to minimize overall unit downtime, and because such outages are generally planned to occur only once every six years. During the 2010 Outage, Ameren conducted 108 discrete maintenance, repair and

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replacement projects at Unit 2. Some of these other projects are of the same size and scope as the Projects at issue. Ameren generally prepares a Post Outage Report detailing the work that is performed during an outage. A true and correct copy of the 2010 Unit 1 Post Outage Report is attached hereto as Attachment 2.

12. Of the 108 projects conducted during the 2010 Outage, I understand that only 3 are at issue in this case: the replacement of the reheater, economizer, and air heater components. Moreover, in addition to these 108 projects, during the same 2010 Outage, Ameren performed innumerable tasks as part of the boiler overhaul, all designed to improve the long-term reliability, availability, and efficiency of the boiler. These tasks are not captured in detail in the Post Outage Report.

The Expected Effect of the Projects on the Units' Actual Post-Project Generation of Electricity

13. In my experience, Ameren assesses the impact that a project is expected to have on unit operations well before beginning construction, as part of its project planning and justification processes. Consistent with its normal practice, Ameren assessed the impact of the 2007 and 2010 Projects before beginning construction of those projects. As one of the engineers who had responsibility for preparing the project justification documents for these Projects, I was one of several Ameren personnel who assessed these issues. Typically, we assessed such issues together as a group, and reached a group consensus.

14. Prior to the Projects, I had been involved with dozens of projects at Ameren's other plants that were similar in nature and scope to the Projects. In particular, I had experience with reheater replacements at Labadie; economizer replacements at Labadie, Sioux and

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Meramec; lower slope replacements at Labadie and air preheater replacements at Labadie and Meramec.

15. In my experience, replacement activities such as the Projects do not cause the unit's generation to increase. These are all like-kind replacements, substituting one component for another, sometimes with minor changes in design that made the units more efficient. I understood that my colleagues at Ameren shared the same views.

16. I expected that these replacement projects would improve the efficiency of the units. The economizer replacements were specified to be more efficient than the designs they replaced. Moreover, by replacing the economizer and air preheater with new components with slightly changed designs that could better handle the low-sulfur coal that Rush Island was burning, the auxiliary power demands on the units would be reduced, making the units more efficient overall.

17. I did not expect the Projects to increase the equivalent availability of the unit as compared to the pre-project periods. (Equivalent availability is a measure of the unit's availability to operate and produce electricity. It is a common metric for availability that is used throughout Ameren, and to my knowledge the electric utility industry.) I understood that my colleagues at Ameren shared the same views.

18. This is true for at least two reasons. First, the equivalent availability of the Rush Island units before these Projects was already exceptional – above 90% and at times reaching annual rates of 95% to 96%. In my experience, it is unlikely for any coal-fired unit to achieve sustained equivalent availability above those levels. Second, generating units are complex machines that consist of thousands of components, most of which can and do fail at some point. It is the combined operation of all of these component parts that determines the level of unit

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availability. Based on decades of experience, I knew that these other components would continue to fail, limiting the overall availability of the unit. I understood that my colleagues at Ameren shared the same views.

19. I did not expect the Projects to increase the stated generating capability of the unit as compared to the pre-project periods, other than by increasing the units' efficiency. When ordering the components (reheater, lower slope, economizer, and air preheater) Ameren specified that the new components have the same thermal performance as the old components, meaning that the new components would not increase capability.

20. I am informed and believe that the documents set forth on Attachment 3 hereto, and attached as exhibits to Ameren's various motions being filed contemporaneously, are copies of Ameren's business records, made at or near the time of the occurrence of the matters set forth by, or from information transmitted by, a person with knowledge of those matters, kept in the course of regularly conducted activity, and made by the regularly conducted activity as a regular practice.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 23, 2015



David Boll

JRH-D3

ATTACHMENT 1

**ATTACHMENT
REDACTED**

JRH-D3

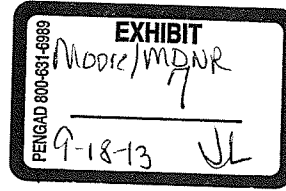
ATTACHMENT 2

**ATTACHMENT
REDACTED**

ATTACHMENT 3

Attachment 3 to the Declaration of David Boll

| <i>Exhibits</i> | |
|-----------------|---|
| C1 | Unit 1 RELS Project Justification Package, AM-00072570 |
| C2 | Unit 1 Air Preheater Project Justification Package, AM-00072850 |
| C3 | Unit 2 RELS Project Justification Package, AM-00072829 |
| C4 | Unit 2 Air Preheater Project Justification Package, AM-00072906 |
| C5 | Ameren 2005 Unit Capabilities Tables, AM-00943285 |
| C6 | Ameren 2006 Unit Capabilities Tables, AM-00175922 |
| C7 | Ameren 2009 Unit Capabilities Tables, AM-00067238 |



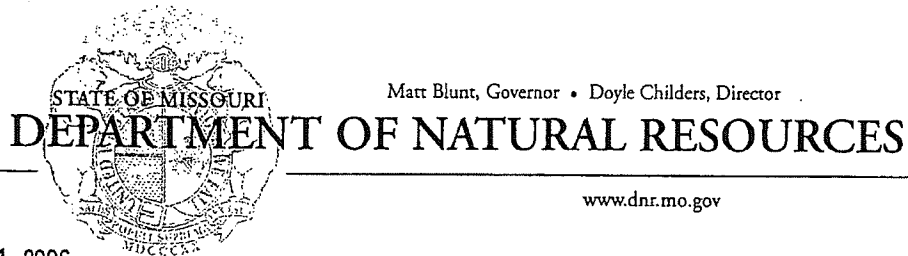
State of Missouri
Department of Natural Resources

Permit Action Management System (PAMS)

| | |
|--|--|
| Permit Review #: AP200605022 Record ID: 3310911 Permit Type: AP: Applicability Determination Request Date Received: 5/9/2006 Description: Replace Burners Program: APCP DNR's Staff: Klein, Lina | Facility Facility ID: AP0001750001 Facility Name: Associated Electric (Thomas Hill Plant) Location: 5693 Hwy F, City: Clifton Hill ST: MO County: Randolph Zip: 65244 Address Two: |
| Status Start Date: 5/9/2006 Permit No: Compl. Date: Exp. Date: Status: On Schedule Current Phase: Executive Review Current Step: AP: No Permit Required | Applicant Name: Associated Electric Cooperative Address One: 2814 S. Golden Address Two: PO Box 754 City: Springfield ST: MO Zip: 65801 Phone: (417) 881-1204 Cnsltng. Firm: Todd Tolbert |

Permit Timeline

| Phase | Step Name | Start Date | End Date | Agency Days Planned | Agency Days Used | Applicant Days Planned | Applicant Days Used | |
|--------------------------|--|------------|-----------|--------------------------------|------------------|------------------------|---------------------|---|
| Check Application | | | | | | | | |
| | 10 AP: Receive, Log, Assign | 5/9/2006 | 5/19/2006 | 3 | 10 | 0 | 0 | |
| Check Application | | | | | | | | |
| | 20 AP: Awaiting Completeness Check Assigned to Lina on 5/19/06 KH | 5/19/2006 | 5/19/2006 | 27 | 1 | 0 | 0 | |
| Technical Review | | | | | | | | |
| | 30 AP: Technical Review | 5/19/2006 | 6/29/2006 | 106 | 41 | 0 | 0 | |
| Executive Review | | | | | | | | |
| | 40 AP: Unit Chief Review turned in to kendall 6/29. Ljk | 6/29/2006 | 7/18/2006 | 14 | 19 | 0 | 0 | |
| Executive Review | | | | | | | | |
| | 41 AP: Final Clerical Prep Prepping no construction permit required ltr for KLM signature. 7/19/06 kdm. Prep complete to KLM to sign. | 7/18/2006 | 7/19/2006 | | 0 | 0 | 1 | |
| Executive Review | | | | | | | | |
| | 42 AP: Executive Review To KLM to sign. 7/19/06 kdm. Recd signed ltr from KLM. 7/21/06 kdm. | 7/19/2006 | 7/21/2006 | | 0 | 0 | 2 | |
| Executive Review | | | | | | | | |
| | 50 AP: No Permit Required No construction permit required ltr mailed. File ready to prep for file room. 7/21/06 kdm. File prepped and sent of file room. 7/21/06 kdm. | 7/21/2006 | 7/21/2006 | 0 | 0 | 0 | 1 | |
| | | | | Totals: | 150 | 71 | 0 | 4 |
| | | | | Days Since Last Action: | | 0 | | |



Matt Blunt, Governor • Doyle Childers, Director

DEPARTMENT OF NATURAL RESOURCES

www.dnr.mo.gov

JUL 21 2006

Mr. Todd A. Tolbert
Environmental Specialist II
Associated Electric Cooperative, Inc. - Thomas Hill Plant
P.O. Box 754
Springfield, MO 65801

RE: New Source Review Applicability Determination Request - Project: 2006-05-022
Installation ID Number: 175-0001

Dear Mr. Tolbert:

Your request for a determination of permit need for the replacement of cyclone burners for units 1 and 2 was reviewed by my staff. According to Missouri State Rule 10 CSR 10-6.060, *Construction Permits Required*, **no construction permit is required** from the Missouri Air Pollution Control Program.

The cyclones in the two Thomas Hill units have been in service for over 37 years. Over the years coal ash and slag have accumulated within the metal casing that surrounds the inlet header and the barrel tubes. The ash and slag have combined with water from tube leaks to form a corrosive environment that has reduced the wall thickness of the cyclone barrel tubes. Ultrasonic readings have found areas where the wall thickness is only 0.1000-inch thick, compared to the original 0.250-inch thickness. In addition to the new cyclone barrel tubes, re-entry throat tubes, inlet/outlet/intermediate headers, upper and lower neck headers, and shut-off and control dampers will also be replaced.

The replacement parts for this project are expected to be \$10 million for Unit 1 and \$15 million for Unit 2. Those values represent approximately 2.8 percent of the replacement costs for each unit. Reconstruction is defined in 10 CSR 10-6.020 (2)(R)2 as:

"Where the fixed capital cost of the new components exceeds fifty percent (50%) of the fixed capital cost of a comparable entirely new source of operation or installation."

The replacement does not constitute a reconstruction. Since there will be no increase in the potential to emit, according to the applicant, the change can not be considered a modification, per Missouri State Rule. Therefore, since replacement of the cyclone burners does not meet the definition of construction, reconstruction or modification, the replacement is exempt from permitting requirements.

You are still obligated to meet all applicable air pollution control rules, Department of Natural Resources' rules, or any other applicable federal, state, or local agency regulations. Specifically, you should avoid violating 10 CSR 10-3.030, *Open Burning Restrictions*, 10 CSR 10-6.170, *Restriction of Particulate Matter to the Ambient Air Beyond the Premises of Origin*, and 10 CSR 10-3.090, *Restriction of Emission of Odors*.



JRH-D4

AM-00025868-MDNR

Mr. Todd A. Tolbert
Page Two

A copy of this letter should be kept with the unit and be made available to Department of Natural Resources' personnel upon verbal request.

If you have any questions regarding this determination, please contact Lina Klein at the Air Pollution Control Program, P.O. Box 176, Jefferson City, MO 65102 or you may phone (573) 751-4817. Thank you for your time and cooperation.

Sincerely,

AIR POLLUTION CONTROL PROGRAM



Kyra L. Moore
Permits Section Chief

KLM: lkk

c: Northeast Regional Office
PAMS File 2006-05-022

JRH-D4
AM-00025869-MDNR

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company)
d/b/a Ameren Missouri's Tariffs to Adjust)
Its Revenues for Electric Service.)

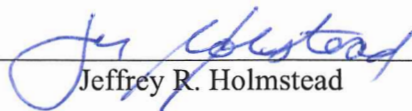
Case No. ER-2022-0337

AFFIDAVIT OF JEFFREY R. HOLMSTEAD

WASHINGTON, D.C.) ss

Jeffrey R. Holmstead, being first duly sworn states:

My name is Jeffrey R. Holmstead, and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.



Jeffrey R. Holmstead

Sworn to me this 27th day of July, 2022.

