Exhibit No.:	
Issue(s):	*Meramec, Rush Island*
Witness:	*Keith Majors*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Surrebuttal/True-Up Direct Testimony*
Case No.:	*ER-2022-0337*
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MISSOURI PUBLIC SERVICE COMMISSION

FINANCIAL AND BUSINESS ANALYSIS DIVISION

AUDITING DEPARTMENT

SURREBUTTAL/TRUE-UP DIRECT TESTIMONY

OF

KEITH MAJORS

UNION ELECTRIC COMPANY,
d/b/a AMEREN MISSOURI

CASE NO. ER-2022-0337

Jefferson City, Missouri
March 2023

TABLE OF CONTENTS OF

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Q. Please state your name and business address.

A. Keith Majors, Fletcher Daniels Office Building, 615 East 13th Street, Room 201, Kansas City, Missouri, 64106.

Q. By whom are you employed and in what capacity?

A. I am a Utility Regulatory Audit Supervisor employed by the Staff ("Staff") of the Missouri Public Service Commission ("Commission").

Q. Are you the same Keith Majors who previously provided testimony in this case?

A. Yes. I provided direct testimony in this case on January 10, 2023 concerning Staff's revenue requirement recommendation and other various adjustments and topics. I provided supplemental direct testimony on January 24 concerning Staff's updated revenue requirement used for Staff's Class Cost of Service ("CCOS") study. I provided rebuttal testimony on February 15 concerning regulatory lag, business risk, and the Rush Island Generating Station.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to respond to the rebuttal testimony of Ameren Missouri witnesses Mitchell Lansford and John Reed.

EXECUTIVE SUMMARY

Q. Please provide a brief summary of your surrebuttal testimony.

A. My surrebuttal testimony will respond to portions of Ameren Witness Mitchell Lansford. Specifically, I respond to these issues on the corresponding pages of his rebuttal testimony:

- Meramec Regulatory Asset : pages 2-5
- Legal Expense: page 21

I also respond to witness John Reed concerning various portions of his rebuttal testimony. I will identify and explain why Staff's Rush Island adjustment reducing the plant and accumulated reserve balances is necessary to preserve just and reasonable rates for ratepayers.

MERAMEC REGULATORY ASSET

Q. On page 2 of his rebuttal testimony, Mr. Lansford references Staff witness Lisa Ferguson's rebuttal testimony in Case No. ER-2021-0240. How did that rate case conclude and how was the Meramec issue resolved?

A. The case concluded with a stipulation and agreement that established a regulatory asset for the remaining net book value of Meramec to be amortized over five years beginning with the effective date of rates on February 28, 2022.

Q. In regard to Ms. Ferguson's testimony in Case ER-2021-0240, Mr. Lansford claims she supported rate base treatment of any Meramec deferrals. Was this the agreement ultimately struck by the parties?

A. No. The Stipulation and Agreement in that rate case specifically stated "Carrying costs on the unamortized balance as of future rate case, if any, will be addressed in those future rate cases." Most importantly, whatever facets of the recommendations concerning Meramec proffered by Staff and Company in the 2021 Rate Case were set aside when the parties agreed on the specific language in the Stipulation and Agreement.

Q. Has the Commission recently decided the issue of inclusion in rate base of retired generating facilities?

A. Yes. In both the *Report and Order* and the *Amended Report and Order* in Case No. ER-2022-0130, the Commission denied recovery of the net book value of Sibley in rate base. These orders were effective in November and December 2022 which was after Ms. Ferguson's testimony. Staff's recommendation in this case adopts the most recent and relevant Commission guidance on this topic.

Q. How does the Meramec amortization benefit Ameren Missouri?

A. If Meramec were retired like other plant (i.e., without a special amortization), an equal amount would have been removed from plant and accumulated depreciation expense pursuant to mass asset accounting. Meramec had approximately $50 million of undepreciated plant at the time the deferral was established. This would reduce the reserve by a like amount, and increase the net rate base upon which Ameren Missouri would earn a rate of return by $50 million. The $50 million would also increase depreciation accruals as depreciation expenses going forward would be increased to adjust for the $50 million deficit. Ameren Missouri would effectively recover the $50 million deficit over the time period of future depreciation expense.

On the contrary, by amortizing the Meramec regulatory asset over five years, Ameren Missouri receives greatly accelerated recovery of the $50 million. Accelerated recovery is one reason why this deferral should not be included in rate base and earn a return.

Q. On page 5 of his rebuttal testimony, Mr. Lansford identifies additional investment at Meramec related to the retirement. Does Staff recommend any adjustments or different accounting treatment for these investments?

A. No. These investments will be included in plant-in-service and be depreciated and included in rate base.

Q. Can you provide examples of when a public utility commission allowed recovery of an undepreciated plant but denied a rate of return on the investment?

A. Yes. Both the Texas PUC[1] and the Arkansas PSC[2] allowed Southwestern Electric Power Company ("SWEPCO") to establish a regulatory asset for the undepreciated plant at Dolet Hills. The Texas PUC afforded the same accounting treatment to another SWEPCO plant, Welsh Unit 2.[3] The orders by these PUCs rejected the Company's request to earn a rate of return on its investment once the plant retired.

Q. What were Dolet Hills and Welsh Unit 2?

A. Dolet Hills was a lignite coal fired power plant of about 650 MW capacity. It was retired at the end of 2021 due to the inability to supply fuel to run the facility.[4] Welsh Unit 2, also owned by SWEPCO, was a sub-bituminous coal fired power plant of 528 MW capacity. It was retired in April 2016 due to looming environmental compliance costs that proved uneconomic to further operate the unit.

[1] Public Utility Commission of Texas., Docket No. 51415, Application of Southwestern Electric Power Company for Authority to Change Rates, Final Order (Jan. 14, 2022) at paragraphs 44-65, pages 10-13.
[2] Arkansas PSC Docket No, 21-070-U, Application of Southwestern Electric Power Company for Approval of a General Change in Rate and Tariffs, Order No. 14 (May 23, 2022) at page 50.
[3] Public Utility Commission of Texas, Docket No. 46449, Application of Southwestern Electric Power Company for Authority to Change Rates, Final Order (Jan. 11, 2018) at paragraphs 65-71, pages 19-20.
[4] Ibid, at page 49. Dolet Hills burned lignite coal, which was mined locally in Louisiana.

The Arkansas PSC stated in its order, "In this case, customers should not bear 100 percent of the costs when the economic life of Dolet Hills becomes out of sync with its planned useful life."

The Texas PUC stated in its order, "With respect to the period after December 31, 2021 (the post-retirement phase of the Dolet Hills rate rider), the remaining net book values of Dolet Hills should be placed in a regulatory asset to be amortized without a return."

The Texas PUC stated the following concerning Welsh Unit 2, providing more justification for denying a return on the undepreciated balance:

> 66. Welsh unit 2 no longer generates electricity and is not used and useful to SWEPCO in providing electric service to the public.
>
> 67. Under the FERC uniform system of accounts, the appropriate accounting treatment for the retirement is to credit plant in service with the original cost of Welsh unit 2 and debit accumulated depreciation with the same amount. This would leave a debit balance in accumulated depreciation equal to the undepreciated balance of Welsh unit 2.
>
> 68. Because Welsh unit 2 is no longer used and useful, SWEPCO may not include its investment associated with the plant in its rate base, and may not earn a return on that remaining investment.
>
> 69. Allowing SWEPCO a return of, but not on, its remaining investment in Welsh unit 2 balances the interests of ratepayers and shareholders with respect to a plant that no longer provides service.
>
> 70. It is reasonable for SWEPCO to recover the remaining undepreciated balance of Welsh unit 2 over the 24-year remaining lives of Welsh units 1 and 3.
>
> 71. The appropriate accounting treatment that results in the appropriate ratemaking treatment is to record the undepreciated balance of Welsh unit 2 in a regulatory-asset account.[5]

[5] Public Utility Commission of Texas., Docket No. 46449, Application of Southwestern Electric Power Company for Authority to Change Rates, Final Order (Jan. 11, 2018) at paragraphs 66-71, pages 19-20.

LEGAL FEES

Q. On page 21 of his testimony, Mr. Lansford discusses Staff's Rush Island legal expense adjustment. Why has Ameren Missouri incurred these legal fees?

A. These legal fees are a direct result of Ameren Missouri's litigation with the Environmental Protection Agency and the Department of Justice. As discussed at length in Staff and Company's direct and rebuttal testimonies, Ameren Missouri was found to be in violation of the Clean Air Act.

Q. Is this litigation a result of Ameren Missouri's imprudent decision making?

A. In my opinion, yes. I discuss Ameren Missouri's imprudent actions regarding Rush Island later in this testimony. These legal expenses related to the appeals will not be incurred going forward. These legal expenses should not be included as they will no longer be incurred and they were incurred as a result of Ameren Missouri's imprudent decision making.

Q. Did Staff adjust any of Ameren Missouri's other legal fees?

A. No. The remainder of the test year legal fees are included in test year expenses.

RUSH ISLAND PRUDENCE

Q. Provide a brief summary of this issue and the witnesses involved.

A. Rush Island is a two unit coal fired power station in the St. Louis vicinity. The history of the Clean Air Act violations associated with these units in concert with substantial improvements installed at this power station can be found in these testimonies in this case:

Staff

- Claire Eubanks – direct, rebuttal
- Keith Majors – rebuttal
- Shawn Lange – direct, rebuttal

Ameren Missouri

- Jeffrey R. Holmstead – direct
- Karl Moor – direct
- Matt Michels – direct
- Mark Birk – direct
- John J. Reed – rebuttal
- Andrew Meyer - rebuttal

In this testimony, I respond to John J. Reed's rebuttal testimony.

Ameren Missouri was found in violation of the Clean Air Act and its operating permit by carrying out the Rush Island projects without obtaining the required permits, installing best-available pollution control technology, and otherwise meeting applicable requirements by the United States District Court, Eastern District of Missouri, Eastern Division. This ruling was upheld by the United States Court of Appeals for the Eighth Circuit.

Although lengthy, I have included the United States District Court, Eastern District of Missouri, Eastern Division, Case No. 4:11-CV-00077-RWS decision as Schedule KM-s1, referred to here as the "District Court Opinion". This case was appealed to the United States Court of Appeals for the Eighth Circuit, Case No. 19-3220. The Court's opinion is attached to this document as Schedule KM-s2, and is referred to here as the "Court of Appeals Opinion".

The District Court opinion is the most important document relevant to this issue. This 195 page document explains in great detail how Ameren Missouri engaged in faulty and imprudent decision making given the facts and circumstances known at the time the Rush Island improvements were planned and installed.

Q. Please briefly explain the Rush Island violations of the Clean Air Act.

A. Rush Island is subject to the Clean Air Act of 1970 enacted by the United States Congress. The New Source Review ("NSR") provisions within the Clean Air Act of 1970 have authority over increases in harmful pollutants such as sulphur dioxide at issue here. The

Prevention of Significant Deterioration Program ("PSD") is designed to prevent significant increases in pollution, in part, by requiring major emitters of pollution to install state-of-the-art pollution controls.

As the District Court noted, "[w]hen it enacted the PSD program, Congress required all new major-emitting facilities to comply with PSD requirements by installing state-of-the-art pollution controls at the time of construction. Recognizing the expense and burden of installing such controls, however, Congress did not require facilities then in existence to immediately install pollution controls. Rather, Congress allowed these facilities to continue to operate without installing such controls on the condition that if they ever modified their facilities, they would calculate the impact of those modifications, report the planned modifications to the EPA, obtain the requisite permits, and install the required pollution control technologies at that time. PSD rules apply to "major modifications," which occur when there is a "physical change" or change in the method of operation of a major stationary source that would significantly increase net emissions."[6] The District Court also noted, "An increase of 40 tons or more per year of sulfur dioxide ("SO2"), the pollutant discussed in this case, is "significant" under the regulations. 40 C.F.R. § 52.21(b)(23)(i)."[7]

The "major modifications" at issue were the 2007 and 2010 improvements to Rush Island 1 and 2, respectively. The specific boiler components at issue in the major modifications were the economizer, reheater, lower slopes, and air preheaters that were replaced at Rush Island Unit 1 in 2007, and the economizer, reheater, and air preheaters that were replaced at Rush Island Unit 2 in 2010.

[6] District Court Opinion, page 2.
[7] Ibid.

The District Court performed a thorough examination of all the decisions made with the information known by Ameren Missouri at the time of the projects. The District Court concluded that Ameren Missouri failed to evaluate the project with the NSR and PSD requirements in mind. After the finding by the District Court, Ameren Missouri's two choices regarding Rush Island were to install flue gas desulphurization ("FGD") equipment to control SO2, or retire the units. Ameren Missouri chose to retire the units which should occur within the next two years.

Q. On pages 3-6 of his rebuttal testimony, Mr. Reed discusses the Missouri prudence standard. What is that standard?

A. Mr. Reed discusses a recent The Empire District Electric Company d/b/a Liberty "(Liberty") *Report and Order* that authorized securitization of "energy transition costs" associated with the retirement of its Asbury coal-fired electric generating plant and extraordinary costs incurred during the weather event of February 2021, known as Winter Storm Uri.

The Commission earlier discussed the prudence standard in the Report and Order in Case No. ER-2010-0355, a Kansas City Power & Light rate case:

> The prudence standard is articulated in the *Associated Natural Gas Case* as follows:
>
> [A] utility's costs are presumed to be prudently incurred.... However, the presumption does not survive —a showing of inefficiency or improvidence.
>
> . . . [W]here some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent. (Citations omitted).
>
> In the [Union Electric] case, the PSC noted that this test of prudence should not be based upon hindsight, but upon a reasonableness standard:

> [T]he company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company.[8]

The Commission continued in that Report and Order:

> 18. As stated above, under the prudence standard, the Commission presumes that the utility‘s costs were prudently incurred.[9] This means that utilities seeking a rate increase are not required to demonstrate their cases-in-chief that all expenditures were prudent.[10]
>
> 19. Staff or any other party can challenge the presumption of prudence by creating ―a serious doubt as to the prudence of an expenditure. Once a serious doubt has been raised, then the burden shifts to KCP&L to dispel those doubts and prove that the questioned expenditure was prudent.
>
> 20. In a prior case involving a prudence review and construction audit, the Commission stated:[11]
>
> The Federal Power Act imposes on the Company the ―burden of proof to show that the increased rate or charge is just and reasonable. Edison relies on Supreme Court precedent for the proposition that a utility‘s cost are [sic] presumed to be prudently incurred. However, the presumption does not survive ―a showing of inefficiency or improvidence. As the Commission has explained, ―utilities seeking a rate increase are not required to demonstrate in their cases-in-chief that all expenditures were prudent . . . However, where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent.”
>
> 21. Thus, in the first instance, it is the parties challenging the decisions and expenditures of a utility that have the initial burden defeating the

[8] See State ex. Re. Associated Natural Gas v. Public Serv. Comm’n, 954 S.W.2d 520, 528-529 (Mo. App. W.D. 1997).
[9] See State ex. Re. Associated Natural Gas v. Public Serv. Comm’n, 954 S.W.2d 520 (Mo. App. W.D. 1997); State ex rel. GS Technologies Operating Co. Inc. v. Public Serv. Comm’n, 116 S.W.3d 680 (Mo. App. W.D. 2003 (citations omitted).
[10] See Union Electric, 66 P.U.R.4th at 212.
[11] In the Matter of Union Electric Company, 27 Mo.P.S.C. (N.S.) 183, 193 (1985) (quoting Anaheim, Riverside, etc. v. Federal Energy Regulatory Commission, 669 F.2d 779 (D.C. Cir. 1981)) (citations omitted).

> presumption of prudence accorded the utility.[12] Under the prudence standard, the Commission looks at whether the utility‘s conduct was reasonable at the time, under all of the circumstances. In applying this standard, the Commission presumes that the utility‘s costs were prudently incurred.[13]
>
> 22. Once the presumption of prudence is dispelled, the utility has the burden of showing that the challenged items were indeed prudent.[14]
>
> 23. The Commission has adopted a standard of reasonable care requiring due diligence for evaluating the prudence of a utility‘s conduct.[15] The Commission has described this standard as follows:[16]
>
> The Commission will assess management decisions at the time they are made and ask the question, "Given all the surrounding circumstances existing at the time, did management use due diligence to address all relevant factors and information known or available to it when it assessed the situation?"

Q. On page 5 of his rebuttal testimony, Mr. Reed discusses how the Commission has evaluated prudence in past cases. How did the Commission evaluate prudence in the past?

A. As Mr. Reed stated, the Commission, in the Callaway rate case[17], further recognized that the prudence standard is not based on hindsight, but upon a reasonableness standard:

> The Commission determines that the appropriate standard to be used in this case was enunciated by the New York Public Service Commission in Re: *Consolidated Edison Company of New* York, Inc., 45 P.U.R., 4th, 1982. In that case at page 331, the New York Commission rejected an earlier "rational basis" standard in favor of reasonable care standard:

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[12] State ex rel. Associated Natural Gas Company v. Public Service Commission, 954 S.W.2d 520, 528-529 (Mo. App., W.D. 1997).
[13] State ex rel. GS Technologies Operating Company, Inc. v. Public Service Commission, 116 S.W.3d 680 (Mo. App., W.D. 2003).
[14] Associated Natural Gas, supra, 954 S.W.2d at 528-529.
[15] Union Electric, 27 Mo.P.S.C. (N.S.) at 194.
[16] Ibid.
[17] Case Nos. EO-85-17 and ER-85-160.

> More recently, and in cases more directly on point, we have articulated the standard against which a utility's conduct in circumstances such as these should be measured as follows:
>
> "…the company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in the reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company. Case 27123, Re: Consolidated Edison Company of New York, Inc., Opinion 79-1, January 16, 1979."

Q. On page 22, Mr. Reed notes that "[Staff] Witness [Claire] Eubanks makes clear that she is not proposing this disallowance on the grounds of prudence" in regard to the Rush Island disallowance. Does this equate to an affirmative endorsement of the prudence of Ameren Missouri's decision making?

A. No. In her rebuttal testimony, Staff witness Claire Eubanks responded to the following question on page 4:

> Q. Based on the above discussion, do you agree with Ameren witness Birk that Ameren Missouri made prudent decisions related to the 2007 and 2010 outages?
>
> A. No…I will let my colleague speak for herself, but in my read of the Eastern District Opinion and the Appeal Court Opinion, it is without question that Ameren Missouri acted imprudently when it failed to evaluate the Rush Island projects for applicability of the New Source Review standards promulgated by the Clean Air Act. I will explain what actions, or in Ameren Missouri's case, inactions, were imprudent later in this testimony.

Q. On page 23, Mr. Reed claims statements made by witness Eubanks concerning Rush Island are factually incorrect. How do you respond?

A. Ms. Eubanks states, in her rebuttal testimony, that only a portion of the Rush Island units are needed to serve Ameren Missouri and support MISO. She also states that

Rush Island is not fully available to serve customers, and that Rush Island will only operate for System Support Resource ("SSR") reliability purposes.

Rush Island is a base load coal fired power plant. But for the SSR agreement with MISO, Rush Island would operate when economic market conditions dictate. As the Eastern District Court noted:

> 50. According to retired Ameren senior vice president Charles Naslund, PRB coal is the cheapest fuel option for the Rush Island plant, and Ameren has the cheapest fuel costs in the regional transmission area, known as the Midcontinent Independent System Operator ("MISO") area. "So when I bid in my units, basically my units are always picked up pretty much baseload because I'm the cheapest." Naslund Dep., Sept. 18, 2014, Tr. 144:17 – 145:7; Knodel Test., Tr.Vol. 1-A, 104:22-105:09. The economic advantage provided by burning cheaper coal than their competitors means Rush Island Units 1 and 2 run a higher percentage of the time. Naslund Test.,Tr. Vol. 6-A, 48:7-49:3.[18]

Baseload units such as Rush Island are designed to operate when available. The Court noted that after the project was completed, unit 1 operated 8,568 hours in the year out of a possible 8,760 hours, or 97.8% of the year.[19]

Conversely, the SSR agreement constricts the operation of the Rush Island units. As opposed to operating under economic dispatch, these units will be called upon only for reliability purposes. This reduced operation is the basis for Staff's plant reduction for Rush Island.

Q. On page 23, Mr. Reed notes that there is no evidence whatsoever that the SSR obligations have not been met by Ameren Missouri. Do you disagree?

[18] District Court Opinion, Page 17.
[19] Ibid, page 76.

A. No, but Mr. Reed misses the point. But for Ameren Missouri's imprudent decision making, the SSR agreement would not exist and Rush Island would, all things being equal, be economically dispatched by MISO like Ameren Missouri's remaining coal fleet.

Q. On page 24, Mr. Reed discusses capacity factors and the concept of used and useful. Is Rush Island used and useful for the provision of utility service?

A. No, not entirely. Rush Island was designed to operate 24 hours per day, 7 days per week if and when available like Ameren Missouri's remaining coal fleet and moreover modern coal fired power plants, generally speaking. As a result of Ameren Missouri's poor decision making, Rush Island now operates under the SSR agreement and has materially limited the unit's operations. As Staff witness Claire Eubanks noted in her rebuttal testimony, the reality is Rush Island is not fully available, not fully used and useful for service, and there are limitations on its operations.

Mr. Reed compares Rush Island to both the combustion turbine fleet and the now retired Meramec facility. Both comparisons miss the mark. Combustion turbines are designed to run intermittently during peak demand at a very low capacity factor. Barring an emergency situation, these units cannot safely or economically operate continuously and were not designed to do so. They are used and useful for what they are – combustion turbine *peaking* units. Baseload facilities and peaking facilities have vastly different construction costs and operating economics and it is an inapt comparison of the two. Baseload units such as coal and nuclear have very high capital costs with the tradeoff of low incremental fuel expense. The more these units are operated the more high fixed costs can be spread out for each megawatt-hour generated. Conversely, peaking units have relatively low capital costs and high incremental fuel expense.

The Meramec facility, like so many other vintage 1950's coal units in their later years, was inefficient compared to other available generation but if called upon, was available. The difference here is that Rush Island has been curtailed from now until final retirement. Neither Ameren Missouri nor its customers are receiving the full benefit of the Rush Island investment but customers are still paying the high fixed cost and maintenance costs.

On page 26, Mr. Reed identifies that Rush Island are required to be fully available to be called on to address system reliability needs. This is much different than economic dispatch. Generally speaking, Ameren Missouri's coal fleet and coal plants in general are operated when system operators, such as MISO and SPP, call on them to operate. Low-cost baseload units like Rush Island are frequently, if not always called upon to operate continuously if able, thereby generating low-cost energy for the benefit of customers.

Q. You claim that Ameren Missouri's actions or inactions were imprudent. What evidence do you have of this imprudence?

A. In examination of the 195 page opinion of the District Court, it is clear to me that Ameren Missouri chose not to consider the increase in availability and therefore increase in emissions caused by the improvements at Rush Island. This line of decision making led to the Notice of Violation from the EPA, the years of litigation of the violations, and ultimately the premature retirement of Rush Island 15 years prior to its 2039 retirement date.

Q. Did the District Court or the Appeals Court consider prudence in either of their opinions?

A. I am not an attorney, but the words "prudent" or "prudence" do not appear in either opinion. However, Judge Rodney W. Sippel found that Ameren Missouri violated the Clean Air Act under the "preponderance of the evidence" established by the United States:

> After consideration of the testimony given at trial, the exhibits introduced into evidence, the parties' briefs, and the applicable law, I make the following findings of fact and conclusions of law, which largely adopt those proposed by the United States. As discussed below, I conclude the United States has established that Ameren should have expected, and did expect, the projects at Rush Island to increase unit availability (and, for Unit 2, to increase capacity), which enabled Ameren to run its units more, generate more electricity, and emit significantly more pollution. The United States has also established that Ameren actually emitted significantly more pollution as a result of the projects. Ameren has failed to establish that either the routine maintenance or demand growth defenses apply to shield it from liability. As a result, I conclude that the United States has established by a preponderance of the evidence that Ameren violated the PSD and Title V provisions of the Clean Air Act.[20]

Therefore, while I cannot say the District Court explicitly evaluated the prudence of Ameren Missouri's decision making, the District Court did an excruciatingly thorough examination of Ameren Missouri's actions and decisions surrounding the violations of the Clean Air Act.

The District Court did find that Ameren Missouri's conduct was not reasonable as noted in Judge Sippel's September 30, 2019 *Memorandum Opinion and Order* regarding the remedy phase:[21]

> 393. I have already concluded that a reasonable power plant operator would have known that the modifications undertaken at Rush Island Units 1 and 2 would trigger PSD requirements. I have also concluded that **Ameren's failure** to obtain PSD permits **was notreasonable**. Ameren Missouri, 229 F.Supp.3d at 915-916, 1010-14.
>
> 394. After the liability trial in this case, I found that **at the time** of the Rush Island modifications, "the standard for assessing PSD applicability was well-established." It was also "well-known" that the types of unpermitted projects Ameren undertook **risked** triggering PSD requirements. Id. at 915. [Emphasis Added.]

It is not prudent or reasonable to make decisions that lead to violations of federal law.

[20] District Court Opinion, page 5.
[21] 421 F.Supp.3d 729 (E.D.Mo. 2019), page 794

Q. What are some of the specific facts the District Court identified that show imprudent decision making?

A. Ameren Missouri should have expected improvements in availability at the time NSR and PSD should have been evaluated:

> 257. Ameren also **should have expected** Unit 2's long-term average equivalent availability to increase from 92% to 95%. Because there is a 2-3% variation in long-term forecasts, Ameren understood that Unit 2's highest annual availability after the 2010 boiler upgrade would be 97-98%. Koppe Test., Tr. Vol. 3-A, 76:17-22, 79:7-14; Meiners Test., Tr. Vol. 7-B, 54:14-55:6; Hausman Test., Tr. Vol. 4-B, 65:9–19.[22] [Emphasis added.]

> 268. In addition to improving the availability of both units, the 2010 boiler upgrade **should have been expected** to increase the capability of Rush Island Unit 2. As described further below, because Unit 1 experienced a capability increase after the 2007 boiler upgrade, Ameren should have expected – and did expect – a similar increase to occur after the 2010 boiler upgrade at Unit 2. Koppe Test., Tr. Vol. 3-B, 19:20-25.[23] [Emphasis added.]

> 279. Based on his review of Ameren's documents and data, Mr. Koppe confirmed that Ameren **should have expected, and did expect,** an increase in Unit 2's capability of at least 22 MW (gross) as a result of replacing the economizer, reheater, and air preheater. That additional capability would result from eliminating the effects of pluggage and allow Unit 2 to burn more coal per hour. Koppe Test., Vol. 3-B, 33:14-34:1; *see also* Vol. 3-A, 27:18-25, 29:2-8, Vol. 4-A, 46:23-47:18.[24] [Emphasis added.]

The District Court noted that Ameren Missouri failed to communicate with the EPA concerning the improvements:

> 394. Prior to undertaking the Unit 1 project, Ameren did not communicate with permitting authorities about whether a New Source Review permit would be required. Whitworth Test., Tr. Vol. 11-A, 106:3-7.[25]

[22] District Court Opinion, page 81.
[23] Ibid, page 84.
[24] Ibid, page 88.
[25] Ibid, page 117.

Q. What was the legal standard used by the Court of Appeals to determine PSD liability?

A. I am not an attorney, but in the Court's Opinion, the federal legal standard was summarized:

> There are two ways to establish PSD liability. The United States can satisfy its burden by proving either that: (1) the source should have expected an emissions increase related to the project (the expectations approach); or (2) an emissions increase related to the project actually occurred (the actual emissions approach). *Ameren SJ Decision*, 2016 WL 728234, at *16; *see also 40 C.F.R. § 52.21(a)(2)(iv)(b), (c).*[26]

The Court continued:

> Under the expectations approach, courts must determine what a source should have expected at the time of the project. To prevail, the United States "must show that at the time ofthe projects [defendant] expected, or should have expected, that its modifications would result in a significant net emissions increase." *Ameren SJ Decision*, 2016 WL 728234, at *13 (citingcases and quoting *United States v. Ala. Power Co.*, 730 F.3d 1278, 1282 (11th Cir. 2013) (internal quotations omitted)).[27]

Here, the Court specifically found Ameren Missouri should have known emissions would increase with the improvements at Rush Island:

> The core facts of this case show that before Ameren performed the challenged projects, problems with the components at issue were limiting the units' performance. Replacing those components would improve performance and result in additional use and pollution. That was what Ameren should have expected before the work began. The evidence shows that is what Ameren *did* expect. The evidence also shows that is exactly what happened.[28]

[26] Ibid, page 134.
[27] Ibid, page 135.
[28] Ibid, page 137.

The Court put to rest any argument of reliance on hindsight when it stated "Ameren should have expected a significant net emissions increase and should have obtained a permit before beginning work."[29]

TRUE UP ADJUSTMENTS

Q. Please identify the rate base items and income statement adjustments that you are sponsoring as part of the Staff's true-up filing.

A. I am sponsoring the true-up revenue requirement accounting schedules. I am sponsoring the following Ameren Missouri cost of service items that have been adjusted through the true-up, December 31, 2022. These adjustments are reflected in Staff's true-up accounting schedules.

- Automated Meter Reading cost savings
- Bad debt expense
- Building Rental Revenue and Expense
- Customer Affordability Study
- Miscellaneous Rate Base Items
- Forfeited Discounts (Late Payment Fees)
- Vegetation Management & Infrastructure Inspections
- Meramec obsolete inventory
- Storm restoration expense

Q. Does this conclude your surrebuttal/true-up direct testimony?

A. Yes it does.

[29] Ibid, page 155.

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 KEITH MAJORS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW KEITH MAJORS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Surrebuttal/True-Up Direct Testimony of Keith Majors*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Keith Majors

KEITH MAJORS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 8th day of March 2023.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D. Suzie Mankin

Notary Public

CASE NO. ER-2022-0337

SCHEDULE KM-s1

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

UNITED STATES OF AMERICA,	)	
	)	
Plaintiff,	)	
	)	
vs.	)	Case No. 4:11 CV 77 RWS
	)	
AMEREN MISSOURI,	)	
	)	
Defendant.	)	

MEMORANDUM OPINION AND ORDER

"'Why don't you go up to the Range?' somebody said to me.
'The air is pure, and they have the best water on earth.'"

- W.P. Kinsella
Shoeless Joe

TABLE OF CONTENTS

INTRODUCTION

Plaintiff the United States of America, acting at the request of the Administrator of the United States Environmental Protection Agency ("EPA"), filed this suit against defendant Ameren Missouri ("Ameren") on January 12, 2011. The United States alleges that Ameren committed various violations of the Clean Air Act, 42 U.S.C. § 7401 *et seq.*, the Missouri State Implementation Plan, and Ameren's Rush Island Plant Title V Permit when it allegedly undertook major modifications at its Rush Island Plant in Festus, Missouri without obtaining the required permits. For the reasons that follow, I conclude the United States has established that Ameren violated the Clean Air Act and its operating permit by carrying out the Rush Island projects without obtaining the required permits, installing best-available pollution control technology, and otherwise meeting applicable requirements.

The modern Clean Air Act was passed in 1970 in order "'to speed up, expand, and intensify the war against air pollution in the United States with a view to assuring that the air we breathe throughout the nation is wholesome once again.'" *United States v. Duke Energy Corp.* ("*Duke Energy 2010*"), No. 1:00 CV 01262, 2010 WL 3023517, at *2 (M.D.N.C. July 28, 2010) (quoting H.R. Rep. No. 91-1146, at 1 (1970), reprinted in 1970 U.S.C.C.A.N. 5356). By 1977, Congress had determined that earlier programs "did too little" to achieve air quality goals and added the New Source Review program ("NSR"), including the Prevention of Significant Deterioration ("PSD") provisions at issue in this case. *See Envtl. Def. v. Duke Energy Corp.*, 549 U.S. 561, 567-68 (2007) ("*Duke Energy 2007*"); *New York v. EPA*, 413 F.3d 3, 12-13 (D.C. Cir. 2005). The PSD program is designed to *prevent* significant increases in pollution, an objective built into the very name of the program. *United States v. Ameren Missouri ("Ameren SJ Decision")*, Case No. 4:11 CV 77 RWS, 2016 WL 728234, at *13 (E.D. Mo. Feb. 24, 2016).

The program is designed to prevent future significant increases in pollution, in part, by requiring major-emitting facilities to employ state-of-the-art pollution controls.

When it enacted the PSD program, Congress required all new major-emitting facilities to comply with PSD requirements by installing state-of-the-art pollution controls at the time of construction. Recognizing the expense and burden of installing such controls, however, Congress did not require facilities then in existence to immediately install pollution controls. Rather, Congress allowed these facilities to continue to operate without installing such controls on the condition that if they ever modified their facilities, they would calculate the impact of those modifications, report the planned modifications to the EPA, obtain the requisite permits, and install the required pollution control technologies at that time. PSD rules apply to "major modifications," which occur when there is a "physical change" or change in the method of operation of a major stationary source that would significantly increase net emissions. *See Ameren SJ Decision*, 2016 WL 728234, at *4. An increase of 40 tons or more per year of sulfur dioxide ("SO_2"), the pollutant discussed in this case, is "significant" under the regulations. 40 C.F.R. § 52.21(b)(23)(i).

Congress enacted these modification provisions to ensure that facilities that were grandfathered into the program would not be allowed "perpetual immunity" from PSD's requirements. *Ala. Power Co. v. Costle*, 636 F.2d 323, 400 (D.C. Cir. 1979). Under the PSD program:

> [O]ld plants [are treated] more leniently than new ones because of the expense of retrofitting pollution-control equipment. But there is an expectation that old plants will wear out and be replaced by new ones that will be subject to the more stringent pollution controls that the Clean Air Act imposes on new plants. One thing that stimulates replacement of an old plant is that aging produces more frequent breakdowns and so reduces a plant's hours of operation and hence its output.

United States v. Cinergy Corp., 458 F.3d 705, 709 (7th Cir. 2006).

Ameren's Rush Island plant includes two coal-fired electric generating units, Units 1 and 2. These units went into service in 1976 and 1977 and were grandfathered into the PSD program. Neither unit has air pollution control devices for SO_2. The Rush Island plant currently emits about 18,000 tons of SO_2 per year. The Rush Island units are big sources of pollution, so even small performance improvements or increases in unit availability can lead to a 40-ton increase in SO_2. It only takes an availability improvement of 0.3% or an additional 21 hours of operation at full power for the Rush Island units to emit more than 40 tons of SO_2.

By 2005, some of the major boiler components in Units 1 and 2 were causing problems that forced Ameren to frequently take the units out of service and made the units underperform, reducing the amount of electricity Ameren could generate and sell from the units. Ameren decided to fix these problems by replacing the problem components with new, redesigned components. Courts in PSD enforcement actions have long recognized that "[i]f the repair or replacement of a problematic component renders a plant more reliable and less susceptible to future shut-downs, the plant will be able to run consistently for a longer period of time," burning more coal and emitting more pollution. *United States v. Ala. Power Co.*, 730 F.3d 1278, 1281 (11th Cir. 2013); *see also United States v. Ohio Edison*, 276 F. Supp. 2d 829, 834-35 (S.D. Ohio 2003). When these conditions occur, as they did here, they trigger a utility's obligation to conduct PSD review, secure the appropriate permits, and install required pollution controls.

This standard for assessing PSD applicability was well-established when Ameren planned its component replacement projects for Units 1 and 2. Ameren's testifying expert conceded that the method used by the United States' experts—which showed that Ameren should have expected the projects to trigger PSD rules—has been "well-known in the industry" since 1999.

But Ameren did not do any quantitative PSD review for the project at Unit 1 and performed a late and fundamentally flawed PSD review for Unit 2. And Ameren did not report its planned modifications to the EPA, obtain the requisite permits, or install state-of-the-art pollution controls. Instead, Ameren went ahead with the projects, spending $34 to $38 million on each unit to replace the problem components. It executed these projects as part of "the most significant outage in Rush Island history," taking each unit completely offline for three to four months. Ameren's engineers justified the upgrade work to company leadership on the basis that the new components would eliminate outages and the investment would be returned in recovered operations.

The evidence shows that by replacing these failing components with new, redesigned components, Ameren should have expected, and did expect, unit availability to improve by much more than 0.3%, allowing the units to operate hundreds of hours more per year after the project. And Ameren should have expected, and did expect, to use that increased availability (and, for Unit 2, increased capacity) to burn more coal, generate more electricity, and emit more SO_2 pollution.

Now that the projects have been completed, the evidence shows that Ameren's expected operational improvements actually occurred. Replacement of the failing components increased availability at both units by eliminating hundreds of outage hours per year. Unit 2 capacity also increased. Ameren's employees have admitted that those availability increases would not have happened but for the projects. As a result of the operational increases, the units ran more, burned more coal, and emitted hundreds of tons more of SO_2 per year.

In response to these projects, the United States filed this suit against Ameren, alleging that Ameren violated the Clean Air Act, the Missouri State Implementation Plan, and Ameren's

Rush Island Plant Title V Permit by performing major modifications on Units 1 and 2 without obtaining the required permits, installing state-of-the-art pollution control technology, or otherwise complying with applicable requirements.

Previously, in ruling on the parties' summary judgment motions, I set out several of the legal standards at issue in this case. *See Ameren SJ Decision*, 2016 WL 728234, at *13 (ruling on the parties' various motions for partial summary judgment and evidentiary motions); *United States v. Ameren Missouri*, 158 F. Supp. 3d 802, 804 (E.D. Mo. 2016) (denying Ameren's motion for full summary judgment). I held a twelve day non-jury trial beginning on August 22, 2016. The parties filed post-trial briefs and proposed findings of fact and conclusions of law on September 30, 2016 and argued outstanding evidentiary issues that were raised at trial. On October 12, 2016, the parties filed responses to each other's post-trial briefs.

After consideration of the testimony given at trial, the exhibits introduced into evidence, the parties' briefs, and the applicable law, I make the following findings of fact and conclusions of law, which largely adopt those proposed by the United States. As discussed below, I conclude the United States has established that Ameren should have expected, and did expect, the projects at Rush Island to increase unit availability (and, for Unit 2, to increase capacity), which enabled Ameren to run its units more, generate more electricity, and emit significantly more pollution. The United States has also established that Ameren actually emitted significantly more pollution as a result of the projects. Ameren has failed to establish that either the routine maintenance or demand growth defenses apply to shield it from liability. As a result, I conclude that the United States has established by a preponderance of the evidence that Ameren violated the PSD and Title V provisions of the Clean Air Act.

FINDINGS OF FACT

I. BACKGROUND CONCERNING THE DEFENDANT, THE RUSH ISLAND PLANT, AND THE APPLICABLE REGULATIONS

A. The Defendant

1. Defendant Ameren Missouri is a Missouri corporation. Defendant's incorporated name is Union Electric Company, but Defendant conducts business under the name Ameren Missouri. Answer to Third Amended Complaint ("Answer"), at ¶ 10 (ECF No. 250); Joint Stipulations of Fact ("Joint Stip."), at ¶ 1 (ECF No. 743).

2. As a corporate entity, Ameren is a "person" within the meaning of the Clean Air Act Section 302(e), 42 U.S.C. 7602(e) and 10 C.S.R. 10-6.020(2). Answer, at ¶ 11; Joint Stip., at ¶ 2.

3. At all times relevant to this case, Ameren has been the owner and/or operator of the Rush Island Plant in Festus, Jefferson County, Missouri. Answer, at ¶¶ 12, 57; Joint Stip., at ¶ 3.

B. The Rush Island Coal-Fired Power Plant

4. The Rush Island coal-fired power plant ("Rush Island Plant") consists, in part, of Units 1 and 2, which are coal-fired electric generating units. Rush Island Units 1 and 2 went into commercial service in 1976 and 1977, respectively. Answer, at ¶¶ 13, 59; Joint Stip., at ¶ 4.

5. The Rush Island units were originally designed to have an approximately 30-year life. Testimony of U.S. Power Plant Expert Bill Stevens, Trial Transcript Volume ("Tr. Vol."), 1-B 50:24-51:4, 69:4-11. The components of large units like the Rush Island units typically have a life of between 30 and 40 years. Stevens Test., Tr. Vol. 1-B 81:19 – 82:1.

6. The Rush Island units were designed as baseload units, meaning they generally operate every hour that they are available to run. Design Data Report (Pl. Ex. 297), at AUE-00022523, 22526; Testimony of Retired Ameren Vice President Charles Naslund, Tr. Vol. 6-A, 55:4-7; Anderson Dep., Dec. 4, 2013, Tr., 63:21 – 64:6; Pope Dep., Sept 20, 2013, Tr. 121:18 – 122:11; Testimony of U.S. Utility System Modeling Expert Dr. Ezra Hausman, Tr. Vol. 4-B, 26:15-10; Testimony of EPA Engineer Jon Knodel, Tr. Vol. 1-A, 75:16 – 75:24; 76:21–76:25.

7. The Rush Island units are among Ameren's most cost-effective units and carry much of the system load. Retired Ameren executive vice president Charles Naslund described the units as "two workhorses." Naslund Test., Tr. Vol. 6-A, 50:3-12.

8. Burning coal at Rush Island Units 1 and 2 generates combustion gases containing sulfur dioxide ("SO_2"). The SO_2 gases at Rush Island Units 1 and 2 are passed through a smokestack directly to the atmosphere, as neither unit has air pollution control devices for SO_2. Testimony of U.S. Emissions Expert Ranajit Sahu, Tr. Vol. 5, 43:9 – 44:24; Knodel Test., Tr. Vol. 1-A, 73:7 – 73:9.

9. The Rush Island plant currently emits about 18,000 tons per year of SO_2. Knodel Testimony, Tr. Vol. 1-A, 73:16 – 73:18. If Ameren operated scrubbers at Rush Island that achieved emissions reductions comparable to other plants in the region that currently operate scrubbers, SO_2 emissions would be reduced to several hundred tons per year. Knodel Test., Tr. Vol. 1-A, 108:3 – 108:5.

C. Facts Concerning General Applicability of the Prevention of Significant Deterioration Program

10. The Clean Air Act's New Source Review ("NSR") program consists of a Prevention of Significant Deterioration ("PSD") program and a Nonattainment New Source

Review program. The PSD program applies in areas that are in attainment with the National Ambient Air Quality Standards ("NAAQS") for a particular pollutant or are unclassifiable. 42 U.S.C. §§ 7471, 7475. Knodel Test., Tr. Vol. 1-A, 52:11 - 53:4.

11. The Rush Island Plant is located approximately 50 miles south of St. Louis, Missouri, in the southern tip of Jefferson County, which is currently designated as in nonattainment with the NAAQS for SO_2. Knodel Test., Tr. Vol. 1-A, 53:8 – 53:15 At the time of the 2007 and 2010 projects at issue in this case, Jefferson County was classified as in attainment with the NAAQS for SO_2. Answer, at ¶ 19.

12. At all times relevant to this case, the Rush Island Plant has been a fossil-fuel fired steam electric plant of more than 250 million British thermal units per hour heat input, and has had the potential to emit more than 100 tons per year of SO_2. The Rush Island Plant is a "major emitting facility" as defined by 42 U.S.C. § 7479(1), and a "major stationary source" as defined by 40 C.F.R. § 52.21(b)(1) and 42 U.S.C. § 7602(j). Answer, at ¶¶ 58, 59; Knodel Test., Tr. Vol. 1-A, 53:16 – 54:1.

13. Rush Island Units 1 and 2 are each a "major emitting facility" as defined by 42 U.S.C. § 7479(1), a "major stationary source" as defined by 40 C.F.R. § 52.21(b)(1), and an "electric utility steam generating unit" as defined by 40 C.F.R. § 52.21(b)(31). Joint Stip., at ¶ 5.

14. At the time of the 2007 and 2010 projects, the applicable EPA-approved Missouri PSD regulations were found in the 2003 version of 40 C.F.R. § 52.21, as incorporated into Missouri Rule 10 C.S.R. 10-6.060. Before a major source of air pollution located in such an area designated as in attainment with the NAAQS undergoes a "major modification," the owner or operator of the source must obtain a PSD permit that imposes emission limits. *See* January 21,

2016 Memorandum and Order (ECF No. 711); 40 C.F.R. § 52.21(a)(2), (j); 71 Fed. Reg. 36,486 (June 27, 2006).

15. The PSD regulations define "major modification" as "any physical change … that would result in" a significant net emission increase in actual emissions from a major stationary source. *See* January 21, 2016 Memorandum and Order (ECF No. 711); 40 C.F.R. § 52.21(a)(2)(i).

16. Under the PSD regulations, a "physical change" does not include "routine maintenance, repair and replacement." 40 C.F.R. § 52.21(a)(2)(iii).

17. Under the PSD regulations, a "significant" increase in SO_2 is 40 tons per year. 40 C.F.R. § 52.21(b)(23)(i).

D. Notice of the Violations Alleged in the Complaint

18. The EPA issued a Notice of Violation on January 26, 2010, and issued amended Notices of Violation on October 14, 2010 and May 27, 2011. The Notices of Violation identified, *inter alia*, the alleged violations arising from the 2007 and 2010 major modifications of Rush Island Units 1 and 2 that are at issue in this case. Answer, at ¶ 6; Joint Stip., at ¶ 6.

19. The Notices of Violation were provided to Ameren and the State of Missouri, in accordance with 42 U.S.C. § 7413(a). Answer, at ¶ 6; Joint Stip., at ¶ 7.

20. The United States filed its original Complaint on January 12, 2011 (ECF No. 1), an Amended Complaint on June 28, 2011 (ECF No. 36), a Second Amended Complaint on October 30, 2013 (ECF No. 165), and a Third Amended Complaint on April 24, 2014 (ECF No. 249). The Amended Complaint, Second Amended Complaint, and Third Amended Complaint alleged, *inter alia*, violations arising from the 2007 and 2010 major modifications of Rush Island

Units 1 and 2 that are at issue in this case, and were filed more than 30 days after notice of the violations was provided as required by 42 U.S.C. § 7413(a). Joint Stip., at ¶ 8.

21. The United States provided notice of the commencement of this action to the State of Missouri, as required by 42 U.S.C. § 7413(b). Knodel Test., Tr. Vol. 1-A, 87:4 - 87:23.

II. FACTS CONCERNING THE 2007 AND 2010 BOILER UPGRADES AT RUSH ISLAND UNITS 1 AND 2

22. The major modifications in this case arise from construction projects undertaken by Ameren in 2007 and 2010 at Rush Island Units 1 and 2. The 2007 major modification occurred at Rush Island Unit 1 during a major boiler outage that began on February 17, 2007 and ended on May 28, 2007. The 2010 major modification occurred at Rush Island Unit 2 during a major boiler outage that began on January 1, 2010 and ended on April 9, 2010. Stevens Test., Tr. Vol. 2-A, 24:9 -24:15; 2007 Post Outage Report (Pl. Ex. 34), at AM-02252210; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973.

A. The Boiler Components at Issue and Their Role in Burning Coal to Generate Electricity

23. Rush Island Units 1 and 2 each include a large boiler where coal is burned to convert water into steam. The boilers are comprised of a number of major components, including the economizers, reheaters, lower slope panels, and air preheaters at issue. The economizer, reheater, and lower slope panels are each comprised of bundles of steel tubes designed to carry high-temperature, high-pressure steam to the turbines. Altogether, the boilers in large coal-fired units like those at Rush Island are constructed of hundreds of miles of tubing. Exposing the steel tube bundles in the major boiler components to the heat from burning coal converts water into steam. The steam is sent to the turbines, including a high pressure turbine, an intermediate pressure turbine, and a low pressure turbine. The turbines spin a generator, which

produces electricity. Unlike the tubular boiler components, the air preheater does not consist of steel tube bundles; it consists of metal heat exchanging surfaces that preheat additional air used for combustion of coal in the boiler. Stevens Test., Tr. Vol. 1-B, 55:9 - 55:13, 57:13 - 61:6; *see also* Welcome to Rush Island Plant Presentation (Pl. Ex. 35), at AM-02253169-173.

24. The Rush Island boiler house is approximately 270 feet tall from the ground to the rooftop. Stevens Test., Tr. Vol. 1-B, 95:10-16. Each boiler is approximately 230 feet tall. Stevens Test., Tr. Vol. 1-B, 95: 10-18; Welcome to Rush Island Presentation, (Pl. Ex. 35), at AM-02253171. Each furnace is approximately 60 feet wide and 50 feet deep. Stevens Test., Tr. Vol. 1-B, 96:2-5.

25. The specific boiler components at issue in the major modifications are the economizer, reheater, lower slopes, and air preheaters that were replaced at Rush Island Unit 1 in 2007, and the economizer, reheater, and air preheaters that were replaced at Rush Island Unit 2 in 2010. Knodel Test., Tr. Vol. 1-A, 81:9 - 82:8; Stevens Test., Tr. Vol. 1-B, 46:2-12.

26. The Rush Island economizers are located in the convection section of each boiler. Stevens Test., Tr. Vol. 2-A, 29:11-24. The purpose of the economizer, which is the first tubular heat exchanging component in the boiler, is to take heat from the hot gases in the boiler and transfer it to high pressure boiler feedwater. When it leaves the economizer, the water is close to turning into steam. It then flows to a steam drum before being circulated through waterwall tubes that form the walls of the boiler furnace, and on to a section of the boiler known as the superheating section, before being sent as steam to the high pressure turbine. Stevens Test., Tr. Vol. 1-B, 58:12 – 60:6.

27. Each economizer at Rush Island Unit 1 and 2 weighed approximately 600 tons. Stevens Test., Tr. Vol. 2-A, 34:22 – 35:7. The original Unit 1 and Unit 2 economizers had

identical designs. They each had two banks – an upper and a lower bank – with 276 assemblies per bank, and had a spiral-finned design, with a staggered arrangement. The diameter of each tube was 1.75 inches. Stevens Test., Tr. Vol. 2-A, 29:25 - 30:18; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080276; Ameren's Response to Request for Admission ("RFA") Nos. 362, 364, 365, 367 (ECF. No. 785-1).

28. The Rush Island reheaters are located at the top of each boiler's furnace. Stevens Test., Tr. Vol 2-A, 41:14-42:13. The purpose of the reheater is to reheat steam after it has passed through the high pressure turbine, before being sent back to the intermediate and low pressure turbines. Stevens Test., Tr. Vol. 1-B, 60:7 – 60:17.

29. The original Rush Island reheaters each had a front section and a rear section. The front section had 72 side-by-side assemblies, each of which was over 50 feet tall. The front assemblies were spaced on ten inch centers. The original front section had a sloped bottom, which created a close clearance between the bottom of the reheaters' front section and each boiler's nose. The rear section had 145 assemblies, each of which was around 26 feet tall. Both the front and rear reheater sections were spaced, not platenized, meaning there was no material that connected one tube to the next. Stevens Test., Tr. Vol. 2-A 42:2 - 43:2; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080428; RFA Nos. 386, 387, 389, 390.

30. Rush Island's lower slope tubes are part of the waterwall tubes and are located in the bottom of the furnace area of the boiler. Stevens Test., Tr. Vol. 1-B, 61:15-24, Tr. Vol. 2-A, 51:2 -51:19.

31. In addition to the economizers, reheaters, and lower slopes, the other primary boiler components at issue in this case are the air preheaters, which help warm combustion air entering the boiler. Forced draft ("FD") fans are used to push combustion air into the boiler, and

before entering the furnace the cold combustion air passes through the lower portion of the air preheater. Once in the furnace, the air mixes with pulverized coal and creates flue gas which heats the water and steam in the boiler tube components. Among other things, the flue gas contains tiny particles of ash known as flyash. Stevens Test., Tr. Vol. 1-B, 57:13 – 58:11; Tr. Vol. 2-A, 56:21-57:11.

32. The hot flue gas resulting from coal combustion flows up through the furnace and then from the back pass of the boiler down through the top of the air preheater, before going to the electrostatic precipitator and then being sucked out by induced draft ("ID") fans and sent up the stack. During this process, the air preheater rotates, allowing the hot flue gas exiting the boiler to warm up the forced draft air that is entering the boiler. Stevens Test., Tr. Vol. 2-A 13:10-14, 56:21-58:8; Testimony of U.S. Power Plant Expert Robert Koppe, Tr. Vol. 3-A, at 16:16-17:2.

33. Rush Island Units 1 and 2 each have two air preheaters. Each air preheater is approximately 40 feet tall and is located approximately 100 feet from ground level. Stevens Test., Tr. Vol. 2-A 13:10-14, 67:21-68:5. Each air preheater weighed at least a couple hundred tons. Stevens Test., Tr. Vol. 2-A 59:3-6.

34. The original Rush Island air preheaters were Ljungstrom regenerative air preheaters. Specification No. EC-5491 (Pl. Ex. 10), at AM-00080275. Each original air preheater had three layers: a hot layer, an intermediate layer, and a cold layer. RFA Nos. 329, 332. Each layer was made up of air preheater baskets of various sizes. There were 216 hot end baskets, and each basket was 42 inches thick. There were 216 intermediate end baskets, and each basket was 16 inches thick. RFA No. 333, 334. There were 24 cold end baskets, and each basket was 12 inches thick. Stevens Test., Tr. Vol. 2-A 57:12 - 58:21; RFA No. 335.

35. Because the tubes that comprise the economizers, reheaters, and lower slopes are in constant contact with flue gas and/or combusting coal, these tubes are subject to deterioration over the life of the boiler and eventually develop leaks, which require repair or replacement. When the tubes degrade and the walls become too weak, the high pressure steam or water can burst through, resulting in a boiler tube leak. Large leaks require a unit to shut down while the portion of the tube that ruptured is repaired, which typically lasts two to three days. Koppe Test., Tr. Vol. 3-A, at 14:16-15:9; Stevens Test., Tr. Vol. 1-B, 65:15 - 66:7.

36. Typically, the length of tube replaced when fixing a boiler tube leak would be on the order of several feet of tube. Stevens Test., Tr. Vol. 1-B, 79:4 - 79:19. Such repairs would be part of the day-to-day responsibility of plant maintenance staff and would involve no design changes to the component. Stevens Test., Tr. Vol. 1-B, 65:15 – 66:15, 69:4 – 69:11.

37. Similarly, on occasion some cold end air preheater baskets might need to be replaced due to corrosion. Stevens Test., Tr. Vol. 2-A, 58:14-21.

38. It is well known in the industry that a well-designed section of new boiler tubes should have almost no leaks at all for the first 20 years, before the tubes eventually begin to wear out and start to fail. Koppe Test., Tr. Vol. 3-A 50:11-50:16; Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:24 (Ameren was not expecting any tube leaks with the new economizer).

39. In light of the harsh conditions in which they operate, boiler components typically have a finite design life of between 20 to 40 years of operation. Stevens Test., Tr. Vol. 1-B 83:5-15. At that point, routine maintenance may no longer be sufficient to maintain desired operations, and an alternate approach may be required to optimize and extend the life of the unit. Vol. 1-B, Stevens Test., 82:2-20.

40. As a result, if a utility like Ameren wants to operate a boiler like the Rush Island boilers beyond 25 to 35 years, one strategy would be to replace the major boiler components, including the reheater. Stevens Test., Tr. Vol. 1-B 83:5-21, 84:5-6. Likewise, an economizer should be expected to last approximately 35 years and lower slope tubes should be expected to last approximately 40 years. Stevens Test., Tr. Vol. 1-B 83:22-84:4, 84:7-8. Ameren's expert witness, Mr. Jerry Golden, similarly testified that the typical life of a reheater is about 30 years, the typical life of an economizer is about 35 years, and the typical life of a lower furnace is about 40 years. Golden Test., Tr. Vol. 8-A, 18:2 – 18:11.

41. Life extension activities historically have been considered in the utility industry to be different than typical maintenance activities. The distinction was explained by Mr. Stevens, and is also discussed in an authoritative engineering text published by Babcock and Wilcox known as the "Steam Book." Stevens Test., Tr. Vol. 1-B 76:7 – 76:16, 78:4-7, 80:6-17.

42. According to the Steam Book, prior to the 1980s, it was assumed that older plants would be torn down to make room for newer, larger, more efficient units, and it was common to retire plants after 35 to 40 years of service. That assumption changed when utilities began to engage in life extension activities. The concept of "Life Extension and Upgrades" is discussed in a chapter in the Steam book by that name, while routine maintenance is discussed separately. Golden Test., Tr. Vol. 8-A, 32:16-33:8; Stevens Test., Tr. Vol. 1-B, 78:4-79:3.

43. The Steam Book describes a case-study involving the replacement of an economizer as a "life extension" project. In that life extension case study, a staggered economizer at a coal-fired generating unit was experiencing pluggage and gas flow resistance, resulting in erosion and tube failures. It was replaced with a new, redesigned, in-line

economizer, which alleviated the operational problems and allowed for higher availability and reliability. Stevens Test., Tr. Vol. 1-B 84:19-87:19.

44. By contrast, typical maintenance activities on coal-fired fired boilers are those done on a day-to-day basis to keep the power plant running in its current condition. Such typical maintenance includes things like replacing small sections of tubing, not replacing entire boiler components. Stevens Test., Tr. Vol. 1-B 64:15-66:15; 77:23-78:3, 78:20-79:19, 80:6-12.

45. Similarly, Ameren's Work Order Procedure Manual defines routine maintenance activities as those that "relate to work performed regularly by Ameren employees or contractors on an ongoing basis in the customary and normal course of business to operate or maintain facilities and equipment." Ameren Work Order Procedure (Pl. Ex. 7), at AM-00066968; Stevens Test., Tr. Vol. 1-B 71: 15-72:7. Such routine activities are not subject to the requirements of Ameren's Work Order Procedures. Pl. Ex. 7, at AM-00066960, 66968; Stevens Test., Tr. Vol. 1-B 72:9-14; Moore Dep., Sept. 16, 2014, Tr. 22:11-22.

46. Ameren's Administrative Design Control Manual provides that any activity that changes "any design or operating feature of the plant that is described by drawings or other design documents" is not considered routine maintenance. Ameren Administrative Procedure Design Control Manual (Pl. Ex. 495), at AM-0223699; Stevens Test., Tr. Vol. 2-A, 70:24-71:2.

B. Operational Problems Leading up to the 2007 and 2010 Boiler Upgrades

47. The Rush Island Units were originally designed to burn Southern Illinois Bituminous Coal. Rush Island Resurfacing Study (Pl. Ex. 20), at AM-00499384; Stevens Test., Tr. Vol. 1-B, 100:24 -101:4, Tr. Vol. 2-A, 92:10-92:15. Around 1990, Rush Island began to burn coal from the Powder River Basin in Wyoming, known as PRB coal. Stevens Test., Tr. Vol. 1-B, 101:5-14. By 1995, the Rush Island units were burning 100 percent PRB coal. Stevens

Test., Tr. Vol. 1-B, 101:15-20; Meiners Test., Tr. Vol. 7-A, 102:10-12; Meiners Dep., April 8, 2014, Tr. 237:9-238:11; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080275; Project Approval Package (Pl. Ex. 3), at AM-00072837.

48. Ameren chose to switch to PRB coal, which has less sulfur, in order to comply with the Clean Air Act's separate "Acid Rain" rules. As Ameren explained in an internal 1992 Acid Rain "Compliance Strategy" document, "a significant advantage of a fuel switch strategy is that it delays an irreversible decision to construct scrubbers." Report from Union Electric: Compliance Strategy, Clean Air Act Amendments (Pl. Ex. 798), at AUE-00020365; Knodel Test., Tr. Vol. 1-A, 102:16-21.

49. The Acid Rain rules are part of a program under Title IV of the 1990 Clean Air Act Amendments designed to reduce by about 50% precursors of acid rain, or acid deposition, from coal-fired power plants. These pollutants include SO_2 and nitrogen oxides. Knodel Test., Tr. Vol. 1-A, 55:13-19; *see* 42 U.S.C § 7651 *et seq*.

50. According to retired Ameren senior vice president Charles Naslund, PRB coal is the cheapest fuel option for the Rush Island plant, and Ameren has the cheapest fuel costs in the regional transmission area, known as the Midcontinent Independent System Operator ("MISO") area. "So when I bid in my units, basically my units are always picked up pretty much baseload because I'm the cheapest." Naslund Dep., Sept. 18, 2014, Tr. 144:17 – 145:7; Knodel Test., Tr. Vol. 1-A, 104:22-105:09. The economic advantage provided by burning cheaper coal than their competitors means Rush Island Units 1 and 2 run a higher percentage of the time. Naslund Test., Tr. Vol. 6-A, 48:7-49:3.

51. Although PRB coal was cheaper and had less sulfur, it differed in other important characteristics, including having a lower heating value and higher moisture content, meaning that

more coal needed to be burned to achieve the same output from the units. Stevens Test., Tr. Vol. 1-B, 101:21-102:15; Pope Dep., Sept. 20, 2013, Tr. 71:18-72:9. Because the Rush Island plant was not designed for coal with these characteristics, Ameren knew that switching to PRB would eventually cause operational problems at the units. Meiners Dep., April 8, 2014, Tr. 237:9-238:1; Pope Dep., Sept. 20, 2013, Tr. 73:12-74:12. For instance, Ameren's Acid Rain Compliance Strategy specifically identified the fact that "the low heat content and the higher moisture of these coals generally result in operational problems that reduce capability." Report from Union Electric: Compliance Strategy, Clean Air Act Amendments (Pl. Ex. 798), at AUE-00020397.

52. The anticipated problems from switching to PRB coal for which the units were not designed were realized, causing related operational problems across the entire boiler. These problems worsened over time, and by the mid-2000's, these components were also suffering from additional operational problems due to age-related deterioration, including tube leaks in the boiler components. Fred Pope, Rush Island's former General Manager of Engineering and Technical Services, said Ameren took interim measures to "defer as long as we could the potential component replacements that…we anticipated would eventually come as the result of individual components reaching the end of their life, and we recognized that when that occurred, we would…..adjust the design of those components…to accommodate western coal." Pope Dep., Sept. 20, 2013, Tr. 73:12-74:11.

53. As described further below, these operational problems included boiler tube leaks, slagging, fouling, and plugging, which adversely affected the economizers, reheaters, lower slopes, and air preheaters. These problems, which were extensively described in Ameren's documents, forced each of the units to be completely shut down (in outages) for periods of time,

or to have their electricity generation limited to less than full power (derated) for periods of time. Stevens Test., Tr. Vol. 1-B 102:16-102:24, 105:18-105:20, 107:6 - 109:13; Tr. Vol. 2-A, 7:16-8:20, 59:7-60:22, 63:22-65:7; Koppe Test., Tr. Vol. 3-A, 14:5-15; *see* Project Approval Package (Pl. Ex. 1), at AM-0072580 (noting "tube leaks" and "load reductions due to flyash pluggage" at Unit 1), 72585 (recounting that "switch to 100% PRB coals has caused flyash pluggage" and noting boiler tube leaks at Unit 1), 590 (describing need for Unit 1 replacements following switch to PRB coal); Project Approval Form (Pl. Ex. 2), at AM-00072829 (noting "tube leaks" and "load reductions due to flyash pluggage" at Unit 2); Project Approval Package (Pl. Ex. 3), at AM-00072831 & 837 (same statements for Unit 2); Project Approval Package (Pl. Ex. 6), at AM-00072912 (describing "major boiler modifications" at both units to address components "experiencing an increase in tube leaks" and planned redesigns for PRB coal); July 15, 2005 Email (Pl. Ex. 45) at AM-0266037, 38 (noting derates due to "permanently plugged" air preheaters); September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160 (Unit 2 air preheaters "have continued to foul"); October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322-323 (describing problems in Unit 2 reheater and economizer following switch to PRB coal); Specification No. EC-5491 (Pl. Ex. 10), at AM-00080276-279 (describing problems in Unit 1 and 2 boiler components); Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966724-725, 731-736, 740-742, 745, 750-753 (describing problems in components).

1. Boiler tube leaks

54. As discussed above, boiler tube leaks occur in tubular components such as economizers, reheaters, and lower slopes, and large leaks require a unit to shut down for repairs which typically last two to three days. FOF 35.

55. The rates of boiler tube failures are generally unlike the failure rates that may occur in other equipment in a boiler. Other boiler equipment tends to have failure rates that stay constant with time as long as the utility keeps up with its maintenance. But as boiler tube components degrade and reach the end of their useful life, their failure rates increase with time and become repetitive given the miles of deteriorated tubing, any inch of which can fail. As the component reaches the end of life, the failures will keep increasing even though the utility repairs specific leaks. Koppe Test., Tr. Vol. 3-A, 52:8-54:15.

56. The Rush Island Units were experiencing boiler tube leaks in the years leading up to the 2007 and 2010 major boiler outages, particularly in the three boiler tube components at issue in this case. Koppe Test., Tr. Vol. 3-A 14:5-15. As Ameren's documents described the situation for the Rush Island plant as of 2005, "[t]here were a total of 10 reheat leaks in the reheaters in 2004 alone" along with "a total of 4 economizer tube leaks" and "12 lower slope tube leaks." Project Approval Package (Pl. Ex. 3), at AM-00072837; *see also id*. at AM-00072831 (noting problems that were "causing tube leaks" in the lower slopes and that "[t]here have been tube leaks in the economizer sections and reheater pendants"); Project Approval Package (Pl. Ex. 1), at AM-00072585, 72590 (identical document for Unit 1); 2008 State of the System Presentation (Pl. Ex. 15), at AM-00196730-735 (presentation identifying lost megawatt-hours from boiler tube leaks at both units).

2. Slagging and fouling

57. Slagging is the accumulation of liquid ash on the walls of the furnace and on components that are located at the top of the furnace, including superheaters and reheaters. Slag condenses or solidifies, eventually becoming like rock or concrete. Slag can bridge between tubes causing plugging, which limits flow through the unit. Slag can also fall down through the

furnace, causing tube leaks in the lower slope tubes. Stevens Test., Tr. Vol. 1-B, 104:23 – 105:17; Tr. Vol. 2-A, 51:02-52:25

58. Slag buildup on the reheaters would fall to the bottom of the furnace, causing damage to the lower slope tubes. Stevens Test., Tr. Vol. 2-A 44:1-21; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966735; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080278; Boll Dep., Sept. 5, 2014, Tr. 68:11-70:5. The slag falls caused “a vast number of gouges” on the lower slope tubes, which would often require a unit shutdown to repair. Pl. Ex. 28, AM-00966722, at 745. The slag falls at the Rush Island units were at times as large as an automobile. Stevens Test., Tr. Vol. 2A, 54:2-14; Boll Dep., Sept. 5, 2015, Tr. 69:22-70:5. In addition, the lower slope tubes were experiencing problems related to 30 years of exposure to liquid ash and molten slag. Stevens Test., Tr. Vol. 2-A 51:20 – 52:25, 54:2 – 14; Pl. Ex. 28, at AM-00966745; Project Approval Package (Pl. Ex. 1), at AM-00072585; Project Approval Package (Pl. Ex. 3), at AM-00072831.

59. Before the 2007 major boiler outage, Ameren undertook efforts to repair the tube leaks caused by falling slag. For instance, Ameren would pad-weld over areas eroded by flowing slag and would replace leaking sections of tubes. However, because the buildup of slag was a recurring problem that was not being controlled adequately, problems continued. Stevens Test., Tr. Vol. 2-A 54:15-55:8.

60. Fouling is the deposit of solid particles of ash on heat transfer surfaces. When fouling builds up on itself, it can plug the gas flow path between boiler tubing, limiting gas flow across the component, and through the unit. Fouling also leads to higher velocity gas flows through the areas that are not plugged, which causes erosion and tube failures. Stevens Test., Tr. Vol 1-B, 102:16-103:23, Tr. Vol. 2-A, 32:7-32:23.

3. Pluggage

61. Pluggage at Rush Island Units 1 and 2 occurred in the reheaters and economizer boiler tube components and in the air preheaters. Pluggage in boiler tube components occurs when ash material bridges the spaces between tubes, limiting gas flow. Stevens Test., Tr. Vol. 1-B, 103:24 - 104:4, 104:16 - 104:22. Ash also accumulates on the air preheater surfaces, restricting flue gas flow through the air preheaters and reducing the unit's output. Stevens Test., Tr. Vol. 2-A 59:7 - 60:22; July 15, 2005 Email (Pl. Ex. 45), at AM-0266037, 38; September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160; Koppe Test., Tr. Vol. 3-A, 14:11-14:15, 17:5-17:11.

62. Ameren's documents specifically identified the switch to PRB coal as the reason for increased flyash pluggage and load reductions. Project Approval Package (Pl. Ex. 1), at AM-00072585 ("The switch to 100% PRB coals has caused flyash pluggage in the reheater and economizer. The pluggage in the existing staggered economizer has caused load reductions."); Rush Island Resurfacing Study (Pl. Ex. 20) at AM-00499388 ("changing fuels resulted in economizer performance problems…and maintenance problems…"); Bosch Dep., June 12, 2014, Tr. 38:25 – 39:7; *see also* July 15, 2005 Email (Pl. Ex. 45) at AM-0266037, 38 (noting derates due to "permanently plugged" air preheaters).

63. Mr. Koppe and Mr. Stevens explained that the boiler components were all suffering from the same underlying pluggage problem that collectively contributed to limiting air and gas flow through the boiler, thus reducing the amount of coal that could be burned. Stevens Test., Tr. Vol. 1-B, 108:13-109:13; Koppe Test., Tr. Vol. 3-A, 28:7-14, 29:2-8; see also Koppe Test., Tr. Vol. 4-A, at 46:23-47:18 (discussing the cumulative effect of the air preheaters,

reheater, and economizer pressure differentials on overall pressure drop throughout the boiler and its impact on the ID fans).

64. Jeff Shelton, an Ameren trial witness, similarly testified that because they all collectively contribute to the problem, the air preheaters, economizer, and reheater have to be looked at together when considering the effects of pluggage on the unit's ability to generate. Shelton Test., Tr. Vol. 10-A, 106:13-24.

65. Pluggage in the economizer with PRB ash was exacerbated by the original economizer's staggered alignment design, which created a torturous flow path for the flue gas and ash. Together with the switch to PRB coal, the economizers' staggered alignment also resulted in erosion, thinning, and tube leaks. Stevens Test., Tr. Vol. 2-A 30:19 - 32:14, 33:9-22, 40:11-19.

66. Ameren attempted to remedy the problems in the economizer through soot blowing and off-line cleanings, but these efforts did not solve the problem. Pluggage and erosion kept occurring, and the end of the economizers' lives were approaching. Stevens Test., Tr. Vol. 2-A 32:7-23.

67. The original design of the reheaters also exacerbated pluggage due to PRB coal. The spacing of the reheaters, along with the use of PRB coal, led to pluggage of the gas lanes through the reheaters. Contemporaneous documents indicated that "fouling is a daily concern," that pluggage occurred in certain areas of the reheater across the entire boiler width, and that shotguns and dynamite needed to be used to remove the pluggage. Stevens Test., Tr. Vol 2-A, 43:3-45:13; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966735.

68. Ameren attempted to address the problems with the reheaters through cleanings, including soot blowing, and even dynamite. Strubberg Dep., Nov. 5, 2013, Tr. 162:7-19, 174:9-

23. However, because of end of life considerations, it became necessary to replace the reheaters. Stevens Test., Tr. Vol. 2-A, 44:22 – 45:13, 47:20-24.

69. The original air preheaters also consistently experienced pluggage. With the switch to PRB coal, ash accumulated on the air preheater surfaces and built up on itself. Ultimately, the pluggage also led to an end-of-life situation for the air preheaters. Stevens Test., Tr. Vol. 2-A 59:7 – 60:22. As an internal Ameren email stated, "It sounds like we have to live with the load limitations on RI due to fan capacity limits. Is there anything else we should look at, or as Jon suggests, is this beyond recovery due to the permanently plugged air heaters." July 15, 2005 Email (Pl. Ex. 45), at AM-0266037; Cardinale Dep., July 31, 2014, Tr. 84:3 – 21 (air preheater fouling was "permanent"); *see also* September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160 (noting continued air preheater fouling).

70. The specific mechanisms by which pluggage from PRB coal restricted air and gas flow and limited boiler operation were explained by Mr. Koppe. As noted previously, each boiler's FD fans push air in through the air preheaters where it is warmed up before it enters the furnace areas of the boiler. Koppe Test., Tr. Vol. 3-A 16:16-20. The very hot gases then flow up through all of the boiler tube components and back through the other side of the air preheaters, through the precipitator, and then are sucked out by ID fans, before going out the stack. Koppe Test., Tr. Vol. 3-A 16:20-17:2. When pluggage gets bad enough, it is no longer possible to push enough air into the furnace to burn as much coal as could otherwise be burned. That reduces the amount of coal that is burned, which reduces the amount of steam that is generated, which reduces the amount of electricity that is produced. Koppe Test., Tr. Vol. 3-A, 17:3-11.

71. Pluggage limited the amount of coal that could be burned in several ways. First, pluggage impacted the pressure differentials (also known as "delta P") across the air preheater and economizer, which limited air and gas flow and reduced the amount of coal that could be burned. As discussed above, the hot gases flow through the boiler as air is pushed into the boiler by FD fans and pulled by ID fans. The amount of air pushed into the furnace has to be in balance with the amount of gas that goes out of the furnace. As a component gets plugged, it takes more pressure to push the gas through it. The "delta P" represents the change in pressure from the inlet to the outlet of the various boiler components. When the pressure drop gets too high, the amount of gas flow out of the furnace must be reduced, which requires reducing the amount of air coming into the furnace, which reduces the amount of coal the boiler can burn. Koppe Test., Tr. Vol. 3-A, 17:12-18:21.

72. Second, pluggage also impacted the FD and ID fans. As pluggage got worse, the ID fans, which create a vacuum to suck air out of the boiler, had to work harder and harder to pull air, and eventually got to the point where they were "fan-limited" and could not suck any more without damaging equipment. Cardinale Dep., July 31, 2014, Tr. 103:17-205:17. So the ID fans had to reduce power, which also reduced the amount of coal that could be burned. Koppe Test., Tr. Vol. 3-A., 19:18-20:16.

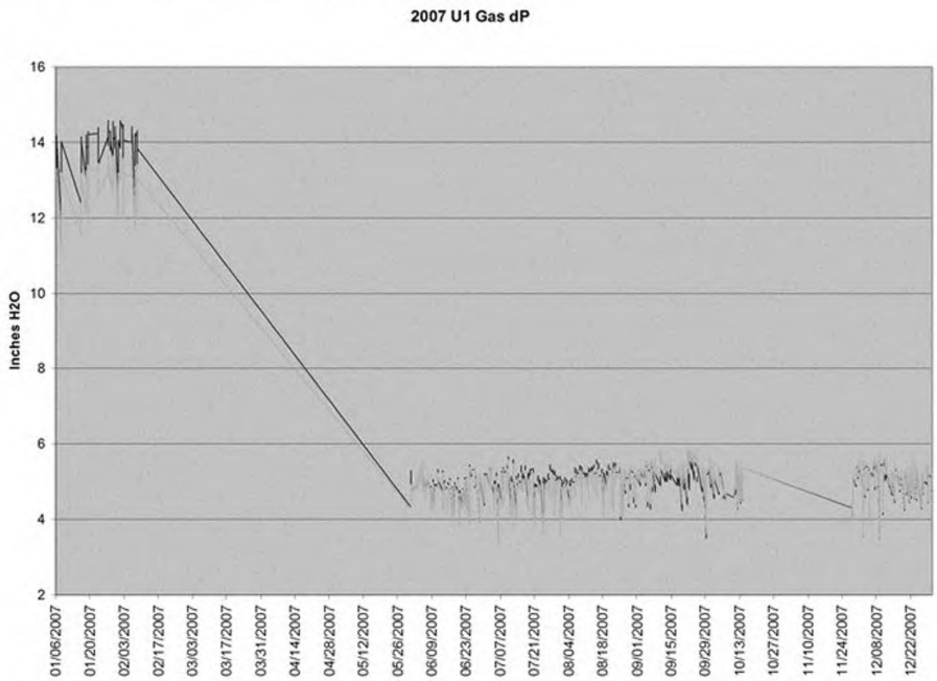
73. As the air preheaters plugged up more and more, the FD fans also had to work harder and harder to get air into the boiler. Bosch Dep., June 12, 2014, Tr. 38:25 – 40:11. Eventually the FD fans were maxed out and they could not push any more air, which limited the amount of coal that could be burned. Bosch Dep., June 12, 2014, Tr. 39:19 – 40:11. This typically happened in the summertime. Koppe Test., Tr. Vol. 3-A, at 20:17-21:11; Koppe Test., Tr. Vol. 4-A 44:13-23 ("on the rare occasions when I have before seen units limited by FD fans,

it is because the pluggage has gotten so severe in the summer months the FD fans use up all their margin and can't push any more air"); Birk Dep., Sept. 24, 2013, Tr. 194:7-16; *see also* July 2005 email, Pl. Ex. 45 (discussing "permanently plugged air heaters" and noting that the units "run out of FD fans when ambient temps come up in the summer months").

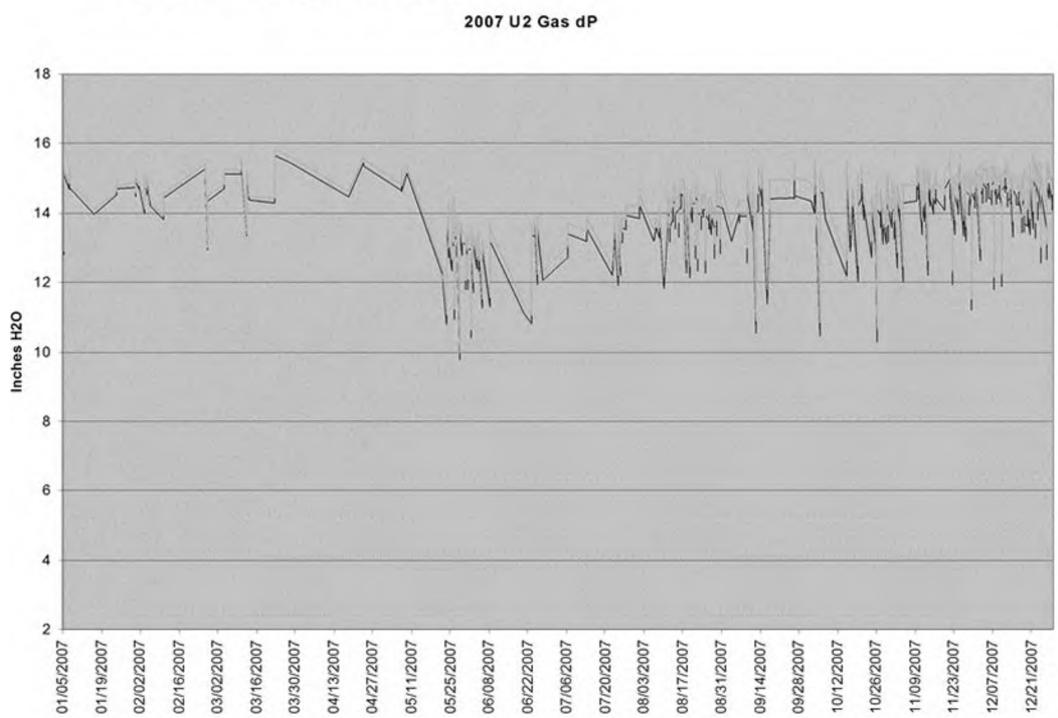
74. In the short term, Ameren coped with pluggage by shutting the units down periodically to conduct high-pressure washes to try to clean out some of the pluggage. Koppe Test., Tr. Vol. 3-A 22:3-12.; Stevens Test., Tr. Vol. 2-A, 59:7-22; Cardinale Dep., July 31, 2014, Tr. 41:15-43:10. This ameliorated the problem somewhat, but it did not solve it. Koppe Test., Tr. Vol. 3-A 22:3-12. The pressure drop would improve somewhat following a cleaning, but "much of the deposits in the air heater were so hard that they couldn't be removed even with a high-pressure wash." *Id*. at 25:12-21; Stevens Test., Tr. Vol. 2-A, 66:8-23; Cardinale Dep., July 31, 2014, Tr. 84:3-21.

75. Evidence of these problems was specifically discussed in company presentations to Ameren executives and memorialized in documents such as the 2008 "State of the System" report. 2008 State of the System (Pl. Ex. 15), AM-00196593, at AM-00196898-923; Meiners Test., Tr. Vol. 7-B, 58:20-59:8 (State of the System presentations were an opportunity to review the performance of plant equipment with Ameren executives). For instance, the 2008 State of the System report included a graphical representation of the high differential pressure problems caused by pluggage, showing very high differential pressure ranging from 12 to over 14 inches of water pressure at the beginning of 2007 at both Unit 1 and Unit 2. The two graphs are found in Pl. Ex. 15, at AM-00196909-10:

2007 U1 Gas dP



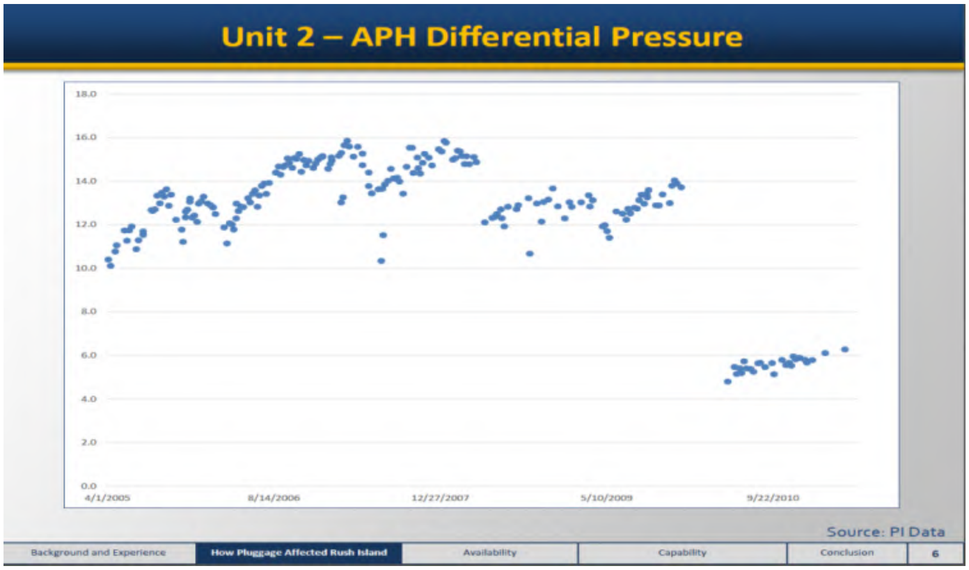
2007 U2 Gas dP



76. At Unit 1, the graphs indicate that differential pressure at Unit 1 dramatically dropped from about 14 inches of water pressure in early 2007 down to 4 to 6 inches of water pressure after the Unit 1 air preheaters were replaced in the Spring of 2007. Pl. Ex. 15, at AM-00196909. At Unit 2, the graph shows the permanence of the pluggage. As compared to the dramatic improvement achieved at Unit 1 due to the boiler component replacements, the Unit 2 graph shows only a very small improvement in differential pressure (from 14 down to 12 inches) following a washing of Unit 2 in the Spring of 2007, which almost immediately crept back up to 14 inches. Pl. Ex. 15, at AM-00196910. Koppe Test., Tr. Vol. 3-A, at 23:15 – 26:3.

77. The differential pressures described in the 2008 State of the System report before the boiler components were replaced were extremely high and caused load reductions. Koppe Test., Tr. Vol. 3-A, at 24:12-25:4. Ameren's trial witnesses Joseph Sind and Andrew Williamson referred to such differential pressures as "extremely high" and indicative of "high pluggage." Sind Test., Tr. Vol. 9-B, at 26:16 – 18 (air preheater differential pressures above even 11 inches are "extremely high"); Williamson Test. Tr. Vol. 9-B, at 44:4-11 (air heater differential pressure of 15 inches indicates "high pluggage").

78. Mr. Koppe's analysis of the company's operational data showed that the same high differential pressures reported in the 2008 State of the System report plagued Unit 2 throughout the years leading up to the 2010 major boiler outage. As Mr. Koppe's review of Ameren's data demonstrated, Unit 2's differential pressure at full load ranged between 10 and 16 inches of water in the years leading up to the projects, before dramatically improving following the 2010 major boiler outage. Koppe Test., Tr. Vol. 3-A 25:22-27:17 (discussing Koppe demonstrative 6).



79. Rush Island's operational data was also compiled in periodic full load tests, which Ameren generally performed on a weekly basis in order to determine the maximum output the unit could achieve at that time. Koppe Test., Tr. Vol. 3-B, 35:17-36:4. During full load tests, the unit tries to generate as much output as it can. Sind Test., Tr. Vol. 9-B, at 30:1-7; Williamson Test., Tr. Vol. 9-B, 42:11-20 (former Rush Island Superintendent of Operations testifying that he reviewed full load tests on a regular basis so he could understand what the capability of the units were); *see also* November 2007 email (Pl. Ex. 130), at AM-02635983 (Rush Island performance engineer James Bosch discussing full load test results after being asked to determine the "capacity" of Unit 1).

80. Plaintiff's Exhibit 928 is a compilation of these full load tests at Unit 2. In addition to reporting actual data such as pressure differentials, each full load test included a row for a possible narrative description of what was limiting load at the time. *See* Pl. Ex. 928, at Spreadsheet Cell B.2 ("Load Limited by"). In addition to the consistently high reported differential pressures, the full load tests performed during the PSD baseline period for Unit 2 (March 2005 to April 2007) are replete with examples where Ameren engineers went out of their

way to indicate in the narrative description of the load test reports that load was limited by the pluggage that is at issue in this case.[1]

81. Ameren also specifically quantified the generation losses due to the boiler components in company presentations. For instance, the 2008 State of the System presentation attributes 185,286 megawatt-hours of lost production at Unit 2 in 2007 to the air preheaters, as compared to only 15,197 megawatt-hours during that same year at Unit 1, which was the year the air preheaters were replaced at Unit 1. 2008 State of the System (Pl. Ex. 15), at AM-00196900.

82. Ameren trial witness David Strubberg conceded that the reported Unit 1 losses were smaller due to the replacement of the air preheaters. Strubberg Test., Tr. Vol. 8-A, 80:12-81:22 (discussing excerpt of presentation in Pl. Ex. 14). Similarly, a July 2006 email from Mr. Strubberg concerning the potential risks of postponing the Unit 1 major boiler outage estimated an approximately 35 MW load reduction due to pluggage. Strubberg Test., Tr. Vol. 8-A, 90:11-91:10.

83. The pluggage at Unit 2 continued to get worse in the years leading up to the 2010 major boiler outage. As ash plugged up the economizer or air preheater, some of it could be removed relatively easily. But a hard layer of ash deposit would form on the surfaces that could

[1] *See* Pl. Ex. 928, at Cell O.2 ("FD Fan Capacity"), W.2 ("ID FAN SUCT PS"), Y.2 ("ID Fan suction press"); AJ.2 ("ECON PLUGGAGE ID FAN SUCT). AK.2 ("Due to pluggage in boiler, it limits ID fan suction pressure"); AL.2 ("limited by the ID fan suction pressure…Boiler is plugged"); AO.2 ("ID suction Supht [sic] plugged Econ plugged"); AP.2 ("ID Fan Suction (Plugged Boiler)"); AQ.2 ("ID Fan Suction (Plugged Boiler)"), BD.2 ("02 blr pluggage"), BF.2 ("FD FANS"); BV.2 ("APH Pluggage"), BW.2 ("APH Pluggage"), BX.2 ("APH Pluggage"), BY.2 ("APH Pluggage"), BZ.2 ("ID Fan Suction Pressure"), CA.2 ("ID FAC SUCTION PRESS."), CC.2 ("ID Fan Suction"); CE.2 ("Blr Pluggage"), CH.2 ("APH Pluggage), CI.2 ("Suction Press."), CJ.2 ("APH Pluggage"), CK.2 ("APH Pluggage"), CN.2 ("ID Fan Suction Pressure"), CO.2 ("APH Pluggage"), CP.2 ("ID suc press Blr & APH's plugged"), CQ.2 ("APH Pluggage"), CR.2 ("ID FAN SUCT"), CS.2 ("APH Pluggage"), CT.2 ("Aph Pluggage"), CU.2 ("APH Pluggage"), CV.2 ("ID fan suction pressure").

not be removed "short of going in with a chisel and chiseling it out inch by inch. So as time went on, the thickness of these hard layers increased and that means that even after washing these components, the pressure drops were still very high." Koppe Test., Tr. Vol. 3-B, 20:1 – 21:7. This inability to remove the load limitations with high pressure washes was specifically identified in project justification documents for Unit 2. An Ameren memo reported: "A high pressure wash can restore some of the pressure loss, but the gains are dimensioning [sic] with an ever increasing accumulation of hardened fly ash." September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160.

84. By 2008, pluggage of the Unit 2 air preheaters had gotten so bad that Ameren had to install a bypass as a temporary measure to allow gas to get around the pluggage. Koppe Test., Tr. Vol. 3-B, 21:8-21:19; Caudill Test., Tr. Vol. 10-B, 40:25-41:7; Cardinale Dep., July 31, 2014, Tr. 103:17-105:17 ("What they did on Unit 2, put in a pipe bypass around the air preheater because they really had serious pluggage problems."). The effect of the bypass would be to increase the electrical output of the unit and decrease its efficiency. Koppe Test., Tr. Vol. 3-B, 21:25 – 22:10; Cardinale Dep., July 31, 2014, Tr. 43:1-45:10 ("certainly bypassing the air preheater is not something you want to do"). Out of all the plants that Mr. Koppe has assessed throughout his career, he has never seen another example of such a bypass being installed. Koppe Test., Tr. Vol. 3-B, 21:20 – 21:24.

85. The effects of pluggage were also well-documented in other contemporaneous documents. Ameren described the pluggage at Unit 2 in a letter it sent to EPA's Clean Air Markets Division in 2008, "Unit 2 generation has been limited to approximately 90 percent of normal load since the middle of 2007 due to gas flow restrictions in the air preheater." April 7, 2008 Letter (Pl. Ex. 934), at AM-00015890-MDNR. When shown the document at trial, Ameren

capability expert witness Mr. Marcus Caudill referred to that amount as a "huge" load limitation. Caudill Test., Tr. Vol. 10-B, 39:19 – 41:14.

86. Similarly, in a December 16, 2009 email, which was written after the boiler work had been performed on Unit 1 but before it had been performed on Unit 2, Ameren employee Jeff Shelton wrote that the difference between the Unit 1 and Unit 2 capabilities grew bigger in the summer "due to draft limitations on Unit 2 and that following the boiler work this outage, we expect Unit 2 to not be as limited in the summer due to the draft issues." December 6, 2009 Email (Pl. Ex. 508), at AM-02248370; Shelton Test., Tr. Vol. 10-A, 93:21-94:18.

87. Mr. Shelton recognized that Unit 2 was draft limited in prior years as well. For instance, Mr. Shelton observed in 2008 that Unit 2 "ran into limitations due to gas path pluggage and air heater dps." December 18, 2008 Email (Pl. Ex. 542); at AM-02462552; Shelton Test., Tr. Vol. 10-A, 96:3-97:4.

88. In light of this evidence, Ameren's expert witness on the capability of the units, Marcus Caudill, agreed that Rush Island Units 1 and 2 were experiencing pluggage that was causing load reductions and derates prior to the 2007 and 2010 outages. Caudill Test., Tr. Vol. 10-B 35:18-22.

4. Availability losses caused by the replaced components prior to the 2007 and 2010 outages as reported to the Generating Availability Data System

89. Ameren uses the Generating Availability Data System ("GADS") to collect and track operating data for the Rush Island plant, including event data and performance data. The event data tracks causes of lost generation such as derates and full outages, while performance data tracks statistics such as generation, fuel usage, and hours of operation. Anderson Test., Tr. Vol. 7-A, 5:22-6:14.

90. Plaintiff's expert Mr. Robert Koppe, who has been a power plant performance consultant since the 1970s, had a leading role in developing the GADS database, including writing the manual that all utilities use in deciding how to report their data. Koppe Test., Tr. Vol. 3-A 7:18 – 11:4. Mr. Koppe developed the original list of cause codes that all utilities use to report events in GADS. *Id*. at 10:17-11:4, 40:9-13.

91. Throughout his career, Mr. Koppe has been hired by dozens of utilities to analyze the performance of their generating units. Koppe Test., Tr. Vol. 3-A 11:5-20. He has analyzed performance issues relating to hundreds of generating units. *Id*. at 13:17-25.

92. GADS is an industry-wide database that collects information on the performance of power plants and the effects that various problems have on that performance. Koppe Test., Tr. Vol. 3-A 10:5-11. GADS was developed so that utilities could improve the performance of their generating units. *Id*. at 10:12-16.

93. Whenever a unit has a problem that limits the amount of electricity it can generate, it is supposed to be reported as an "event" in the GADS data. That could be because the unit was operable but its maximum output was reduced (derated) or because the unit could not operate at all because it was in an outage. Koppe Test., Tr. Vol. 3-A 31:1-9.

94. A statistic known as equivalent availability takes account of the effects of such deratings and outages on the availability of the unit to operate. Koppe Test., Tr. Vol. 3-A at 30:1-19. A derating reflects times when the unit was not capable of operating at its maximum output due to an equipment problem. *Id.*

95. Staff at the Rush Island plant contemporaneously record event data that identifies the causes of lost availability. These event data are then further reviewed for accuracy on a

monthly basis before being uploaded into the company's GADS system. Anderson Test., Tr. Vol. 7-A, 15:9-18.

96. The Ameren performance engineer at the Rush Island plant who was responsible for ensuring the accuracy of the GADS event data was James Bosch. Anderson Test., Tr. Vol. 7-A 42:9-15; Koppe Test., Tr. Vol. 3-A 32:25 – 33:3; Meiners Test., Tr. Vol. 7-B, 38:13-24.

97. It is common for utilities to track the causes of their unavailability so that they can quantify the effects that each problem or component is having on availability. In order to improve availability, utilities need to know what the problems are. Koppe Test., Tr. Vol. 3-A at 31:17-24.

98. Ameren is no different. Unit availability, particularly at low-cost units like the Rush Island units, is very important to Ameren. The company tracks availability "quite closely" and awards salary bonuses under its "Key Performance Indicator" program to some employees based in part on meeting availability targets. Naslund Test., Tr. Vol. 6-B, 8:7-16; Response to Interrogatory No. 65 (ECF No. 823); Moore Rule 30(b)(6) Dep., Sept. 16, 2014, 123:12-124:15; February 6, 2007 Email (Pl. Ex. 103), at AM-02272420.

99. The Key Performance Indicator bonuses are paid for by Ameren's customers. Moore Rule 30(b)(6) Dep., Sept. 16, 2014, 124:16-125:9.

100. Improving unit availability was always a goal for Ameren. If a unit is experiencing forced outages, the company would like it to perform better. Naslund Test, Tr. Vol. 6-B, 11:17-24; 13:15-18. Mr. Naslund, vice president of power operations, told the 1500 Ameren employees under his supervision that perfect availability would be 100%. *Id.*; Generation Times Article (Pl. Ex. 930), at AM-02583221.

101. Staff at the Rush Island plant use GADS data to assess the status of the plant's equipment, and to adjust their predictions of future availability. Anderson Test., Tr. Vol. 7-A 59:25-60:6; Vasel Dep., Aug. 15, 2013, Tr. 83:22-25.

102. The availability targets set by the company are identified down to the tenth of a percentage point. The company also uses availability predictions to know how much coal to buy. Naslund Test., Tr. Vol 6-B, 10:20-11:9; *see also* February 6, 2007 Email (Pl. Ex. 103), at AM-02272420 (discussing proposal to adjust availability KPI bonus target by half a percentage point).

103. Ameren specifically used GADS data to analyze whether to do major capital projects. Koppe Test., Tr. Vol. 3-A at 31:25-34:3. Mr. Bosch, who did not testify at trial, reiterated the importance of such data to the capital project justification process in a 2002 email: "In order to place capital projects in the budget, they must be justified through the EVA program. EVA is a corporate justification software package which incorporates all the required components to derive a recommendation for project approval. ***The most compelling input in the justification calculation is lost generation. These lost generation figures are compiled and easily accessible in the NERC/GADS reporting program*.**" June 25, 2002 Email (Pl. Ex. 99), at AM-02254509 (emphasis added); Bosch Dep., June 12, 2014, Tr. 73:11-74:8; Pope Dep., Sept. 20, 2013, Tr. 25:17-26:4 (management needed to know that there was an economic benefit before approving an investment).

104. Ameren's EVA Program, or Economic Value Added program, was used to compare two scenarios from a financial point of view in order to justify projects and look at the alternatives. Boll Dep. Tr., Dec. 12, 2013, 126:15-127:11; Generation EVA Instructions, (Pl. Ex. 331), at AM-00491836. The company's financial model for justifying projects based on their

availability impacts is capable of determining the effect on anticipated revenue of as little as a 0.1 percentage point change in expected availability. Meiners Test., Tr. Vol. 7-B, 44:23-45:1; June 15, 2009 CPOC Email (Pl. Ex. 895), at 02632840.

105. Ameren also uses GADS availability data to report the causes of lost generation at a plant to financial analysts on quarterly conference calls. Anderson Test., Tr. Vol. 7-A, 16:12 – 16:19.

106. In this case, Mr. Koppe looked at every single event reported in the GADS data for the 60 months prior to the project and determined which ones "would not have occurred but for the problems at issue in the components at issue in this case." Koppe Test., Tr. Vol. 3-A, 34:7-12. Mr. Koppe reviewed each GADS event and description as reported by Ameren for the relevant time period and then reviewed other sources of information to understand the cause of each event. Koppe Test., Tr. Vol. 3-A, 38:18-39:3.

107. Mr. Koppe specifically included the GADS data for the PSD baseline period for Unit 1 that has been used by Ameren in this litigation (February 2005 to January 2007). During that baseline period, problems in the economizer, reheater, lower slopes, and air preheaters caused Unit 1 to lose 336.1 equivalent full power hours of generation per year, which is equivalent to roughly 14 days of operation per year. Koppe Test., Tr. Vol. 3-A, 45:15-46:24. The unit was completely shut down in outages for 246.4 hours per year due to problems in the components at issue and lost the equivalent of another 89.7 full power hours of operation due to deratings. *Id*. These losses were widespread and covered a large fraction of all the months in the baseline. Koppe Test., Tr. Vol. 3-A, 46:25-47:6.

108. Mr. Koppe also specifically reviewed the GADS data for the PSD baseline period for Unit 2 used by Ameren in this litigation (April 2005 to March 2007). During the baseline

period, problems in the economizer, reheater, and air preheaters caused Unit 2 to lose approximately 245 equivalent full power hours of availability per year. The unit was completely shut down in outages for 145.5 hours per year due to problems in the components at issue and lost the equivalent of another approximately 100 full power hours of operation due to deratings. Koppe Test., Tr. Vol. 3-A, 74:7 – 75-2; Sahu Test., Tr. Vol. 5 78:20-79:13.

109. The deratings experienced at Units 1 and 2 were not short-term or one-time events. For instance, Unit 1 was continuously derated for the entire months of June, July, August, September, and October 2006, meaning that the unit was continuously derated every single day of each of those months. Unit 2 similarly experienced continuous derates. Anderson Test., Tr. Vol. 7-A, 50:21-52:16.

110. Mr. Koppe's compilation of derates included certain GADS events identified as "FD fan capacity" limitations because the units would not have been limited by FD fan capacity had it not been for pluggage in the air preheater. Koppe Test., Tr. Vol. 4-A, at 60:9-61:3; *see also* Koppe Test., Tr. Vol; 3-A, 96:19-97:18.

111. Rush Island Plant staff similarly attributed such fan capacity problems to the boiler components at issue. For instance, a spreadsheet attached to an April 30, 2006 email from Robert Meiners indicates that plant staff determined that Units 1 and 2 were experiencing load limitations during the summer of 2005 that would be eliminated once the reheaters, economizers, and air preheaters were replaced. *See* April 30, 2006 Email and Attached Condition Assessment (Pl. Ex. 106), at Rush Island Spreadsheet Tab, Line 63 (noting that "FD Fans" at Unit 1 and Unit 2 "[c]urrently limit load during summer, but should be eliminated with boiler pressure part and APH"); Anderson Test., Tr. Vol. 7-A, 49:8-25.

112. As described by Ameren's engineers at the time, the output of the Rush Island units was limited due to "fan capacity limits" resulting from the "permanently plugged air heaters" at the units. July 15, 2005 Email (Pl. Ex. 45) at AM-0266037 (also noting that the "Unit 2 Air Pre-heater delta P's [were] running at 12 inches at full load" and that the "baskets will have to be replaced on the APH's to make an impact on FD fans"); July 21, 2004 Email (Pl. Ex. 555), at AM-02485899; *see also* FOF 80 & n.2 (summarizing descriptions in weekly full load tests). The limitation on the unit's ability to operate was estimated to cost Ameren approximately $25,000 per day. July 15, 2005 Email (Pl. Ex. 45), at AM-02666038.

5. Reduction in the maximum capability of Unit 2 prior to the 2010 outage

113. In addition to lost availability due to outages and derates as reported in GADS, the switch to PRB coal also resulted in a significant reduction in the reported maximum hourly capability of the units prior to the major boiler outages. Koppe Test., Tr. Vol. 3-A 90:11-91:4, Vol. 4-A, 33:10-34:2.

114. The capability of a unit is the maximum electric output that it can produce at that time if asked to do so. Koppe Test., Tr. Vol. 3-A, 84:14-23. The terms "capability" and "capacity" are often used interchangeably. *Id*. at 85:25-86:5

115. Ameren issued annual capability tables, which "represent the expected average output of each unit based on typical ambient conditions." *See, e.g.*, 2011 Capability Table (Pl. Ex. 257), at AM-00067232. The reported capability of a unit is an estimate of what the utility expects the capability of the unit to be in the following year. Koppe Test., Tr. Vol. 3-A, 84:23-85:2. The magnitude of a reported derating is affected by the reported capability. *Id*. 85:3-10; *see* December 2010 Capability Table (Pl. Ex. 257), at AM-00067232.

116. Gross capability or gross electrical output is the amount of electricity that the generator produces. Net capability or net electrical output is the amount of electricity that goes out to the grid. The difference between net and gross capability is the electricity the plant itself uses to operate, otherwise referred to as auxiliary load. Koppe Test., Tr. Vol. 3-A, 85:11-17; Koppe Test., Tr. Vol. 3-B, 11:6-15; Shelton Test., Tr. Vol. 10-A, 84:10-15.

117. A reduction in auxiliary load is an improvement in net efficiency, but it does not affect the amount of coal that the unit is capable of burning. It just means that less power is used to run the plant and more power is sent to the grid. Generator output is the same, heat input is the same, but more megawatts can be sent to the grid. Koppe Test., Tr. Vol. 3-B, 11:16-12:4; Shelton Test., Tr. Vol. 10-A, 85:8-10.

118. Ameren lowered the reported capability of Unit 2 substantially from 2005 to 2006. The reduction was about 10 megawatts in the winter and 20 megawatts in the summer. Unit 2's reported capability remained essentially the same until 2010 and then increased substantially in 2010 and 2011. Koppe Test., Tr. Vol. 3-A, 88:13-23.

119. The reduction in reported capability was the result of the effects of pluggage. Koppe Test., Tr. Vol. 3-A, 90:11-91:4. In 2005, pluggage caused Unit 2 to frequently not be able to meet its reported capability. Koppe Test., Tr. Vol. 4-A, 33:10-34:2. Similarly, Unit 2 was unable to meet its reported capability in the summer of 2005 due to FD fan capacity limitations. January 4, 2006 Email (Pl. Ex. 157), at AM-027432293; Koppe Test., Tr. Vol. 3-A, 91:9-95:11. The reason the fans were running out of capacity in the summer was because of pluggage in the boiler, specifically pluggage in the air preheater. Koppe Test., Tr. Vol. 3-A, 96:19-97:18. As Ameren documents describe it, the output of the Rush Island units was limited due to "fan capacity limits" resulting from the "permanently plugged air heaters" at the units.

July 15, 2005 Email (Pl. Ex. 45), at AM-02666037. Such problems with summer capacity were also identified in the project justification documents for Unit 2, where Ameren reiterated that "the current air preheater baskets have continued to foul to the extent that fans are load limited particularly in the summer months." September 18, 2009 Memo (Pl. Ex. 26), at AM-000954160; *see also* Cardinale Dep., July 31, 2014, Tr. 84:3 – 21 (noting that air preheater fouling was "permanent").

120. The capability of Unit 2 prior to the 2010 major boiler outage was also measured in Ameren's weekly full load tests. The average capability of Rush Island Unit 2 as measured by Ameren in all of the full load tests that were conducted during the PSD baseline period (March 2005 to April 2007) was only 620 gross megawatts. Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; *see* Pl. Ex. 928 (Rule 1006 summary of full load tests for Unit 2).

121. In the years leading up to the 2010 major boiler outage at Unit 2, Ameren further quantified the megawatt capability loss that was due to the boiler components at issue. In Ameren's 2008 annual "State of the System" presentation in 2008, it assigned "25-30 MW" to the Unit 2 "BLR/AHS replacement" in addition to another 13 megawatts that could be gained from replacing the low pressure turbine. 2008 State of the System (Pl. Ex. 15), at AM-00196628.

122. Ameren assigned 22.5 megawatts to the reheater, economizer, and air preheater in a financial analysis for the 2010 major boiler outage. Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet; Koppe Test., Vol. 3-B, 30:4-32:23. The 22.5 megawatt value was a weighted average based on Ameren's estimate that the component replacements would allow Unit 2 to produce 30 more megawatts of capacity during the three summer months and 20 more megawatts for the remainder of the year. Koppe Test., Tr. Vol. 3-

B, at 27:7-32:23; see Pl. Ex. 48, at "Data Entry" Sheet; July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30 MW gain in summer (3 mos), 20 MW gain balance of year from Reheater, Economizer and APH investment").

123. Ameren's final work order authorizations for the reheater, economizer, and air preheater, completed in the fall of 2009, similarly described that the "combined" effect of these component replacements would result in a "gain of 30 MW in the summer and 20 MW in the winter" at Unit 2. October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; *see* September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160 (same language in air preheater justification that "gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer, and air preheater replacements").

124. Ameren witness David Boll testified in his deposition that these predicted additional megawatts represented "regained capacity" that had been lost due to the inability to pull gas flow through the plugged air preheaters. Boll Test., Tr. Vol. 8-B, 51:23-52:4, 54:21-25.

125. A summary of the anticipated benefits of the work written in 2010 similarly referred to the fact that "[a]pproximately 30 Megawatts of unit capacity will be recovered during the hottest months because of lower gas flow pressure drops through the new economizer and air preheaters." March 31, 2010 Email re Newsletter (Pl. Ex. 893), at AM-02229417.

C. The Approval and Engineering Process for the 2007 and 2010 Major Modifications

126. The formal approval and engineering process for the 2007 and 2010 major boiler projects began at least three years prior to the first outage. The replacement of all four components was considered together for planning purposes, beginning as early as 2004. For instance, by December 2004, Ameren had created a preliminary budget for replacement of the Unit 1 economizer, reheater, lower slope tubes, and air preheaters, at an estimated capital cost of

more than $25 million. Stevens Test., Tr. Vol. 2-A 5:2-7; December 20, 2004 Generating Engineering Budget Project Proposal (Pl. Ex. 323); RFA 393.

127. A 500-page Project Book for Unit 1 was compiled as a reference for the work to be completed during the Unit 1 outage. The replacement of the economizer, reheater, lower slope tubes and air preheaters were coordinated by Alstom Power and generally treated together within the Project Book. Rush Island Unit 1 Project Book (Pl. Ex. 63), at AUE-00156352 (collectively referring to "Reheater, Economizer, Lower Slope, Air Heater Rotor Replacements" as a single major project); *id*. at 365 (same), 519 (same), 539 (same); Stevens Test., Tr. Vol. 2-A. 17:1- 18:10.

128. The documentation in the Project Book also confirmed that one purchase order for engineering, materials, and construction services was issued to Alstom Power as early as 2005, which included the replacement of the economizer, reheater, lower slope tubes, and air preheaters. Pl. Ex. 63, at AUE-00156395-398.

129. The replacements of the economizers, reheaters, lower slopes, and air preheaters were all approved under Ameren's Work Order Procedures. Stevens Test., Tr. Vol. 1-B 72:15-21, 91:19 – 92:3.

130. While the air preheaters were also subject to their own work order justification process, the air preheater justification documents specifically combined the air preheater replacements with the reheater, economizer, and lower slopes as part of a "major refurbishment" at both Unit 1 and Unit 2. October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912; Stevens Test., Tr. Vol. 2-A 9:24-10:18.

131. Similarly, prior to replacing the Unit 2 air preheaters, Ameren reiterated its reliance on the "combined" effect of the air preheaters, reheater, and economizer for purposes of

justifying the replacements. September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323 (same); *see also id*. at AM-00926322 ("Load reductions of 30 MW in the summer and 20 MW for the remainder of the year can be avoided with the new boiler components and the re-designed air preheater.").

132. Ameren's documents also indicate that the replacement of all the components was combined to "gain efficiencies in procurement, design and installation" and described the air preheater replacements as "part of a Major Mechanical Work Package to include the Economizer, Reheater and Lower Slope portion of the boiler." Project Approval Package (Pl. Ex. 1), at AM-00072590; Project Approval Package (Pl. Ex. 4), at AM-00072859; Stevens Test., Tr. Vol. 2-A 10:19-11:18, 13:23-14:7.

133. The engineering specification issued by Ameren called for bids from outside engineering firms for the design, fabrication, and installation of the boiler components at Rush Island Units 1 and 2. Ameren consolidated the replacement of the economizer, reheater, lower slope tubes, and air preheaters for purposes of issuing the specifications. Specification No. EC-5491 (Pl. Ex. 10); Stevens Test., Tr. Vol. 2A 15:19 - 16:13.

134. Ameren provided specific design requirements for the replacement components, including a number of significant design changes that were intended to upgrade and improve the performance of the boiler as a whole. Stevens Test., Tr. Vol. 2-A, 32:24-33:22, 34:8-12, 45:14-46:25, 55:9-56:4, 66:5-67:9; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322 (noting combined project objectives of redesigned economizer and air preheater).

135. In contrast with routine work undertaken at utility plants, the replacement of the economizers, reheaters, lower slopes, and air preheaters required approvals of executives at the highest level of the company, including Ameren's CEO. The approval process required at least

10 layers of approval review. Stevens Test., Tr. Vol. 2-A 7:5-15, 13:15-22; Project Approval Package (Pl. Ex. 1), at AM-00072580; Project Approval Form (Pl. Ex. 2), at AM-00072829; Project Approval Package (Pl. Ex. 4), at AM-00072850; Project Approval (Pl. Ex. 5), at AM-00072906.

136. In August of 2005, Gary Rainwater, then the Ameren CEO, authorized the expenditure of $23,148,000 to replace the economizer, reheater, and lower slope panels at Rush Island Unit 1. Stevens Test., Tr. Vol. 2-A 7:5-15; Project Approval Package (Pl. Ex. 1), at AM-00072580. Mr. Rainwater also authorized the expenditure of $24,988,000 for the same work at Unit 2. Project Approval Form (Pl. Ex. 2), at AM-00072829. Earlier in the spring of 2005, Ameren Missouri Chief Operating Officer Thomas R. Voss authorized the expenditure of approximately $6.9 million for the design, fabrication, and installation of new air preheaters at Unit 1, and, in October of 2005, authorized approximately $7.5 million for similar work at Unit 2. Stevens Test., Tr. Vol. 2-A 13:15-22; Project Approval Package (Pl. Ex. 4), at AM-00072850; Project Approval (Pl. Ex. 5), at AM-00072906.

137. After the 2007 major boiler outage at Unit 1, Unit 2 went through a second justification process in 2009. The Unit 2 major boiler outage had to be approved by an additional committee known as the Capital Project Oversight Committee ("CPOC"), Ameren's CEO Warner Baxter, and the full Board of Directors. Meiners Test., Tr. Vol. 7-B, 45:8-25, 46:6-47:11; May 16, 2009 Email (Pl. Ex. 347), at AM-02637756. On August 14, 2009, Mr. Baxter reported that the outage had been approved. August 14, 2009 Email (Pl. Ex. 553), at AM-02480812.

D. Ameren Justified Replacing the Economizers, Reheaters, Lower Slopes, and Air Preheaters Because They Would Improve Operations and Allow the Units to Generate More

138. Ameren's contemporaneous project authorization documents identified the new economizers, reheaters, lower slopes, and air preheaters as components that were "improved" and "redesigned" in order to fix the operational problems that had been caused by burning PRB coal and age-related deterioration. Stevens Test., Tr. Vol. 2-A, 8:21- 9:6; Project Approval Package (Pl. Ex. 1), at AM-00072580; Project Approval Package (Pl. Ex. 3), at AM-00072831; Boll. Dep. Tr., Dec. 12, 2013, 164:24-165:26, 168:19-169:6; Birk Dep., Sept. 24, 2013, Tr. 194:1-16; Meiners Dep., April 8, 2014, Tr. 237:18-238:11; Pope Dep., Sept. 20, 2013, Tr. 73:12-74:11.

139. Ameren described the planned "major boiler modifications for Rush Island 1 and 2" as follows:

> For several years we have been planning major refurbishment of the Rush Island 1 and 2 boilers, which have operated for nearly 30 years without replacing any of the major components. The major scope elements include the following major components which are experiencing an increase in tube leaks and fatigue issues, and have been redesigned to improve future operation and maintenance:
>
> - Reheater – redesigned for PRB coal
> - Economizer – redesigned for PRB coal
> - Lower Slope – ruggedized design to better withstand slag falls
> - Air Preheater – redesigned for ease of future basket replacement.

Project Approval Package (Pl. Ex. 6), at AM-00072912; Stevens Test., Tr. Vol. 2-A 9:24-10:18.

140. Ameren's expert Jerry Golden agreed that the components replaced at Rush Island were redesigned. Golden Test., Tr. Vol. 8-A, 10:6-10; see also RFA Nos. 377 to 383, 386-387, 389-390, 395-401, 407. Further descriptions of these redesigns are provided below.

141. *Economizer Redesign*: The design of the new economizers was substantially different from the original design. The redesigned economizers were in-line, rather than the original staggered design, which allowed gas to flow through the boiler more easily. The new economizer design made the economizers less subject to fouling and pluggage. Stevens Test., Tr. Vol. 2-A 32:24 – 33:22; 34:8-12; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080325-329; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966728-730.

142. *Reheater Redesign*: The design for the new preheaters was significantly different from the original design. Stevens Test., Tr. Vol., 2-A 45:14 - 18; Boll Dep. Tr., Sept. 5, 2014, 68:11-70. The spacing between the tubes was increased from 10 to 15 inch centers, and the number of front assemblies was reduced from 72 to 48. The bottom of the reheaters was changed from a sloped bottom that closely tracked the boilers' nose to a horizontal bottom. The number of rear assemblies was decreased from 145 to 96 assemblies, and their height was increased. Similar to the design change for the front assemblies, the spacing between each tube was increased. Additionally, both the front and rear assemblies were platenized. Together, these changes allowed more space for gas and ash to flow through the reheaters without plugging or fouling. Stevens Test., Tr. Vol. 2-A 45:14 - 46:25; October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080329-332; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966737-738.

143. *Lower Slopes Redesign*: The design for the new lower slope tubes at Unit 1 was a different design than the original lower slope tubes. Specifically, the new lower slope tubes had a thicker wall to prevent tube leak problems caused by slag falls. The space between each tube was decreased, adding greater strength to assist in slag fall protection. Additionally, the structural support was replaced to provide additional strength. Together, these changes made

the lower slope tubes stiffer, more rigid, and less likely to be crushed so easily. Stevens Test., Tr. Vol. 2-A 55:9 - 56:4; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080332-334; Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966748-749.

144. *Air Preheaters Redesign*: The new, redesigned air preheaters were changed from the original three-layer Ljungstrom regenerative basket design to a two-layer design. The new two-layer air preheaters had a hot end layer and a cold end layer. In each air preheater, each layer had 24 baskets, each of which was 29 inches deep. While the original air preheaters each had 456 baskets, the new air preheaters had only 48 baskets total. The design was changed in order to minimize the outage time required for cleaning the baskets in the future. Stevens Test., Tr. Vol. 2-A 57:12 - 58:21, 66:5 - 67:9; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080279, 348-353; RFA Nos. 331, 334.

145. Ameren specifically justified performing these boiler upgrades because they were expected to reduce forced outages due to tube leaks, eliminate load reductions, and increase the capability and availability of the units to operate. One of the specific expectations identified in the project justifications was that the replacements would eliminate outage time due to the components for the next 20 years. Stevens Test., Tr. Vol. 2-A 7:16-8:20, 25:12 – 26:11, 27:13-23, 59:7-60:22; 63:22-65:7; Golden Test., Tr. Vol. 8-A 12:14 – 13:8.

146. These expected improvements were explicitly stated in Ameren's project justification documents. For instance, after describing the "new, improved, redesigned" economizer, reheater, and lower slopes, **Ameren's project authorization for Unit 1 stated that "as a result" of the replacements, "Rush Island will eliminate forced outages due to reheater tube leaks for 20 years, eliminate 30 to 50 MW load reductions due to flyash pluggage of the current economizer, and reduce the number of tube leaks caused by slag**

falling on the furnace lower slopes." Project Approval Package (Pl. Ex. 1), at AM-00072580 (emphasis added); *see also* Project Approval Package (Pl. Ex. 4), at AM-00072858 (noting expected improvement in pressure drop across the air preheater, and two week reduction in future outage costs due to quicker basket replacements); October 15, 2009 Memo (Pl. Ex. 23), at AM-00926322 (project objectives include avoiding "load reductions" and "minimizing future forced boiler outages for the next 20 years"); September 18, 2009 Memo (Pl. Ex. 26), at AM-0954160 (noting that air preheater replacement "will reduce the gas side pressure loss across the air preheaters from 14 to 5 inches" of water pressure, and that project would result in a megawatt "gain").

147. Ameren expected that the work would reduce the number of forced outages due to these components "to zero." Project Approval Package (Pl. Ex. 1), at AM-00072585-586 ("Flyash pluggage of the economizer will be eliminated or greatly reduced due to the in-line spiral fin economizer… Forced outages due to tube leaks in the reheater and economizer will be reduced to zero."); *see also id*. at 590 ("completing this project will eliminate all the problems"); Project Approval Form (Pl. Ex. 2), at AM-00072829 (same statements for Unit 2); Project Approval Package (Pl. Ex. 3), at AM-00072831-833, 837 (same statements for Unit 2); Presentation re: Justification for Projects (Pl. Ex. 28), at AM-00966731, 740, 750 (identifying avoided costs associated with avoiding derates and outages due to boiler tube leaks); *see also* Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:24.

148. Ameren ultimately decided not to replace the lower slopes at Unit 2 during the 2010 major boiler outage and therefore adjusted the overall availability improvement expected from the work downwards by 0.1% from 4.3% to 4.2%. June 15, 2009 CPOC Email (Pl. Ex. 895), at AM-02632840; Meiners Test., Tr. Vol. 7B, 34:9-35:25.

149. Further evidence of Ameren's expectation of availability improvements is found in Plaintiff's Exhibit 126, which was a presentation that Mr. Meiners made to senior executives at a business plan meeting. Meiners Test., Tr. Vol. 7-B, 27:21-24, 28:18-20. One of the purposes of the presentation was to discuss component replacements and the condition of the reheater, economizer, air preheater, and lower slopes. *Id*. 28:10-17. At the end of the presentation, Mr. Meiners presented a graph showing that Rush Island's availability would increase by almost 5%, from about 90% in 2005-2006 to 95% in the first year after both major boiler outages had been completed. *Id*. 31:15-21

150. Ameren's experts agreed that the expressed purpose of the work at each unit was the same: to improve capability and eliminate deratings. For instance, Mr. Golden confirmed that the work at both units was intended to eliminate pluggage and fouling of the economizers and reheaters, to eliminate future forced and maintenance outages caused by tube leaks, and to eliminate pluggage problems and deratings from the air preheaters. Golden Test., Tr. Vol. 8-A, 10:11-21, 13:16 – 13:21.

151. Mr. Golden also agreed that the purpose of replacing the lower slopes at Unit 1 was to eliminate tube leaks in the lower slope and damage resulting from slag falls and erosion following the switch to PRB coal. Golden Test., Tr. Vol. 8-A, 10:22-25.

152. Ameren's expert Mr. Caudill conceded that the expected benefits of replacing the components included reducing forced outages and eliminating or greatly reducing flyash pluggage at the units. As Mr. Caudill put it, "[b]asically that's what Ameren expected" based on a review of Ameren's project justifications. Caudill Test., Tr. Vol. 10-B, 36:10-37:2, 37:17-38:10.

153. Mr. Caudill also agreed that pluggage in the reheater, economizer, and air preheaters contributed to high differential pressure, which Ameren expected to reduce as a result of replacing the reheater, economizer, and air preheaters. Caudill Test., Tr. Vol. 10-B, 34:17-35:1, 35:14-17. In addition to eliminating load reductions, such improvements in differential pressure can result in some increase in net efficiency, but not gross efficiency. Caudill Test., Tr., Vol. 10-B, 35:11-13; Koppe Test., Tr. Vol. 3-B, 11:16-12:4, 28:18-29:4. Mr. Caudill conceded that Ameren did not justify the replacement of the economizers, reheaters, and air preheaters based on any expectation that they would result in an improvement in gross unit efficiency. Caudill Test., Tr. Vol. Vol. 10-B, 44:24-45:12.

154. Mr. Caudill also conceded that Rush Island Units 1 and 2 were experiencing pluggage that was causing load reductions and derates prior to the 2007 and 2010 outages and that eliminating pluggage that is causing derates will allow a unit to generate at a higher gross load. Caudill Test., Tr. Vol. 10-B, 35:18-22, 37:3-16.

155. Ameren's final, updated justification for the 2010 major boiler outage reflected the company's expectation that the replacements would enable the unit to operate more and to produce more megawatts when operating. The justification identified two types of performance improvements from the boiler work: a capacity increase and an equivalent availability improvement. As described in a 2009 work order authorization request:

> A gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer and air preheater replacements. …. Also included in the justification is an approximate 3-4% improvement in equivalent availability of the unit.
>
> **Assumptions**: It is assumed that these boiler modifications will result in an improved operation of the unit that is at least equal to, if not better, than that currently experienced with Unit 1 which had similar modifications in 2007. This includes fewer load restrictions, improved equivalent availability and elimination of potential catastrophic failure of the economizer.

October 15, 2009 Memo (Pl. Ex. 23), AM-00926323; *see also id*. at AM-00926322 ("Load reductions of 30 MW in the summer and 20 MW for the remainder of the year can be avoided with the new boiler components and the re-designed air preheater."); Stevens Test., Tr. Vol. 2-A, 25:12- 26:11; 27:3-23.

156. The justification of additional generation from the replacements is also found in the financial analysis tool that was used to justify the 2010 outage. The availability gain used in the final financial analysis was the equivalent of "15 days of generation." Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48); Meiners Test., Tr. Vol. 7-B, 18:6-11, 18:21-19:16.

157. Ameren's final financial evaluation separately included a 22.5 MW "projected annual increase … in plant capacity" as a result of the replacement of the reheater, economizer, and air preheater. Economic Value Added (EVA) Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet; Koppe Test., Tr. Vol. 3-B, 30:4-32:23. This capacity increase was based on Ameren's estimate that the component replacements would allow Unit 2 to produce 30 more MW of capacity during the three summer months and 20 MW for the remainder of the year. Koppe Test., Tr. Vol. 3-B, at 27:7-32:23; Pl. Ex. 48, at "Data Entry" Sheet; July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30MW gain in summer (3 mos), 20MW gain balance of year from Reheater, Economizer and APH investment").

158. The 22.5 MW increase in capacity was separate from the availability input used in the model. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 (describing megawatt capability "gain" from boiler upgrade separately from 4.2% equivalent availability impact); Koppe Test., Tr. Vol. 3-B 30:8-31:7. It represented an increase over the capability that

Unit 2 was able to achieve during the pre-project period. Koppe Test., Tr. Vol. 3-B, 28:2-12. The financial impact included significant "incremental power sales" that were calculated to have a favorable impact on ratepayers, shareholders, and earnings. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465691.

159. These boiler capacity and availability gains were also identified separately from an additional 15 megawatt capability gain from replacing the LP turbine with a more efficient design. July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 (describing gains separately in project economic analysis).

160. During the final 2009 approval process for the Unit 2 outage, Mr. Meiners reiterated the accuracy of these forecasts to Ameren's CEO, Mr. Baxter. May 16, 2009 Email (Pl. Ex. 347), at AM-02637756 ("I do believe the model is now a much more accurate representation of the economic benefits."); Meiners Test., Tr. Vol. 7-B, at 46:9-47:11.

E. Implementation of the 2007 and 2010 Major Modifications

161. Ameren installed the new economizer, reheater, two air preheaters, and lower slope panels at Rush Island Unit 1 during an outage that began on February 17, 2007 and ended on May 28, 2007. 2007 Post Outage Report (Pl. Ex. 34), at AM-02252210.

162. On January 24, 2007, almost one month before the Unit 1 major boiler outage was to start, there were already 54 contractors on site. The previous week, 17 truckloads of tubing arrived on site and a crane was being constructed for use in replacing the reheater. Rush Island Project Book (Pl. Ex. 63), at AUE-00156343; Overhead Photo of Laydown Areas (Pl. Ex. 414), AM-00222751. This level of activity on-site, a month before the work had even started, is not typical of routine maintenance at a power plant. Stevens Test., Tr. Vol. 2-A, 18:14-19:19.

163. Ameren installed the new economizer, reheater, and two air preheaters at Rush Island Unit 2 during an outage that began on January 1, 2010 and ended on April 6, 2010. Vol. 2A, Stevens Test., 24:9-15; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973.

164. The replacements took years to design and plan and required the special fabrication of components that were not otherwise available at the Rush Island plant. Specification No. EC-5491 (Pl. Ex. 10), at AM-00080233; Rush Island Project Book (Pl. Ex. 63), at AUE-00156362. Ameren's expert, Jerry Golden, acknowledged at trial that these replacements were not *de minimis* activities. Golden Test., Tr. Vol. 8-A, 33:9-18.

165. The size and extent of the components replaced during the 2007 and 2010 major boiler outages was massive, with the economizers, reheaters, and air preheaters each weighing hundreds of thousands of pounds. Stevens Test., Tr. Vol. 2-A, 13:10-14, 34:22-35:7, 50:11-13, 59:3-6, 67:21-68:5. For example, the new reheaters included two outlet headers that weighed 36,000 pounds each and 144 reheater tube assemblies, including 48 front pendant assemblies that were each approximately 49 feet tall and 96 rear pendant assemblies that were each approximately 35 feet tall. Stevens Test., Tr. Vol 2-A, 45:14-46:25, 50:10-13; Specification No. EC-5491 (Pl. Ex. 10), at AM-00080330-332; RFA Nos. 386-387, 390, 395-398. If the Rush Island economizer's tubing was laid from end-to-end, the length of tubing would stretch around 140 miles. Stevens Test. Tr. Vol. 1-B, 79:20 – 80:5.

166. Given the complexity of the replacements, the components needed to be designed, engineered, and constructed by outside contractors, such as Alstom Power - the original manufacturer of the boilers, and numerous other contractors. The work involved was substantial, requiring hundreds of thousands of man-hours, and was well beyond the capacity of Ameren's

own staff. Stevens Test., Tr. Vol. 2-A, 21:18 – 22: 18; 2007 Post Outage Report (Pl. Ex. 34), at AM-02252259, 260; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739979.

167. Heavy machinery was required to facilitate the removal of old components and installation of new, redesigned components. Multiple monorails were installed in order to maneuver the components. Stevens Test., Tr. Vol. 2-A, 18:24-19:11; 36:6-18; 38:11-19. Multiple large cranes were constructed to remove and lower the old assemblies to the ground and lift the new assemblies to the necessary height within the boiler. Each outage required the construction of two Manitowoc 888 cranes, as well as several other cranes, including Manitowoc 222 and 2250 cranes. Stevens Test., Tr. Vol. 2-A, 18:14-19:19; 48:12-20; 2007 Post Outage Report (Pl. Ex. 34), at AM-0225210; 2010 Post Outage Report (Pl. Ex. 46), at AM-02739973. The largest Manitowoc crane had to be tall enough to remove 50-foot reheater assemblies through the roof at an approximately 270 foot elevation. Stevens Test., Tr. Vol. 2-A, 48:4 -15.

168. The process of removing each old component and installing each new component was highly complex. For the boiler components, each original assembly was cut out and removed one-by-one. Stevens Test., Tr. Vol 2-A, 36:11-19. Cuts had to be made in the side of the boiler lagging and walls at various elevations, including one at around a 200 foot elevation, as well as in the roof of the boiler house. Stevens Test., Tr. Vol. 2-A, 38:11-19, 47:25- 48:3. It would take months to facilitate the removal and re-installation. Stevens Test., Tr. Vol. 2-A, 38:25 – 39:9; 49:2 – 7. Many craftsmen were involved in the cutting and welding process. Stevens Test., Tr. Vol. 2-A, 50:20-51:1.

169. The 2007 major boiler outage at Rush Island Unit 1 lasted 100 days and required more than 1,000 workers and 448,539 total hours of labor, of which 402,109 hours were performed by contractors. Ninety-one percent of the work done during the Unit 1 major boiler

outage was performed by contractors. While other work was performed, the replacement of the economizer, reheater, air preheaters, and lower slope panels was the most significant and costly work performed during the outage. Stevens Test., Tr. Vol. 2-A, 21:18 – 22: 18; 2007 Post Outage Report (Pl. Ex. 34), at AM-0225259, 260.

170. The 2010 major boiler outage at Rush Island Unit 2 lasted approximately 100 days and required more than 350,000 hours of labor, of which 290,953 hours were performed by contractors. An average of 360 contractor staff worked two 10-hour shifts six days a week during the outage. 2010 Post Outage Report (Pl. Ex. 46), at AM-02739976.

171. The 2007 and 2010 major boiler outages were significantly different than typical power plant maintenance, repair, and replacement activities undertaken on a day-to-day basis. Ameren itself did not characterize the replacement of major components such as the reheaters, economizers, air preheaters, and lower slopes at issue in this case as "routine." Instead, Ameren described the work as "major boiler modifications" and identified the work as not recurring and not routine in its project documents. Stevens Test., Tr. Vol. 1-B, 65:24- 66:10, 66:8-71:2; Vol. 2-A, 9:24- 10:18, 11:19-12:2; October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912; Project Approval Package (Pl. Ex. 1), at AM-00072591; Project Approval Package (Pl. Ex. 3), at AM-00072838; RFA No. 460.

172. The 2007 and 2010 major boiler outages were unprecedented events for Rush Island Units 1 and 2. After the 2007 major boiler outage, Ameren's Vice President Mark Birk referred to the outage as the "most significant outage in Rush Island history." May 29, 2007 Email (Pl. Ex. 31). Mr. Birk specifically called out the replacement of several components – including the economizer, reheater, lower slope, and air preheaters – as distinct from "the routine maintenance that had to be performed" during the outage. *Id*. The 2010 major boiler

outage was similarly referred to as "among the most significant in [company] history." Jerry Odehnal Report (Pl. Ex. 40); *see* Vasel Dep., Aug. 15, 2013, Tr. 272:2-23 (describing exhibit 40); see also 2010 State of the System presentation , Pl. Ex. 41, at AM-02493747 (distinguishing the air preheater, reheater and economizer replacements from the "routine maintenance" done during the 2010 outage).

173. By the time of their replacements in 2007 and 2010, the reheaters, economizers, and air preheaters were more than 30 years old, nearing the end of their expected lives. These components had never before been replaced at Rush Island Units 1 and 2. Stevens Test. Tr. Vol. 1-B, 50:24-51:4, 81:19-82:1, 84:9-13; 108:13-109:3; Tr. Vol. 2-A, 9:24-10:18, 43:3-25; Golden Test., Tr. Vol. 8-A, 16:7-16; Vasel Dep., Aug. 15, 2013, Tr. 131:11-132:6; October 5, 2005 Memo (Pl. Ex. 6), at AM-00072912 ("units have operated for nearly 30 years without replacing any of the major components"); Unit 2 ELT Progress Report (Pl. Ex. 110), at AM-02465689 ("The MBO [major boiler outage] is being undertaken to change out 2 major boiler components and the APH that are end of life…"); Unit 2 ELT Progress Report (Pl. Ex. 456), at AM-00953927.

174. Projects such as the economizer, reheater, air preheater, and lower slope replacements are not performed frequently during the life of a typical utility unit. Stevens Test., Tr. Vol. 1-B, 91:11-18. Ameren's expert Mr. Golden agreed that the typical life of a reheater is about 30 years, the typical life of a primary economizer is about 35 years, and the typical life of a lower slope is about 40 years. Golden Test. Tr. Vol. 8-A, 18:2-11. Mr. Golden also testified that complete air heater replacements (including the rotor and all baskets), like the ones done at Rush Island, are not done frequently at any unit. Golden Test., Tr. Vol. Vol. 8-A, 19:9-15.

175. Even looking exclusively to how common work is performed across the utility industry, Mr. Golden was able to identify few, if any, projects that rival the 2007 and 2010 major boiler outages at other Ameren plants or elsewhere in the utility industry. Mr. Golden has worked on 14 NSR cases since 2000 on behalf of electric utilities. Golden Test., Tr. Vol. 8-A, 6:3-16. During that time, he has collected a list of 18,300 projects undertaken at coal-fired power plants that he says are both capital projects and cost more than $100,000. Golden Test., Tr. Vol. 8-A, 25:11-14; 25:24-26:2, 26:13-16. However, Mr. Golden was not able to identify *any* coal-fired unit in the electric utility industry that has replaced the economizer, the reheater, the lower slopes, and the air preheater together. Golden Test., Tr. Vol. 8-A, 19:3-8; *see also* Vasel Dep., Aug. 15, 2013, Tr. 154:11-24 (unable to recall any other outage at Ameren when all components were replaced).

176. Similarly, even for the relatively few air preheater replacements that Mr. Golden did identify (35 out of approximately 1,200 coal-fired generating units operating in 2007), Mr. Golden was unable to testify that all were complete replacements or were comparable to those at Rush Island. Golden Test., Tr. Vol. 8-A, 20:2-23, 28:3-12, 28:17-29:5.

F. The Cost of the 2007 and 2010 Major Modifications

177. Replacement of the reheater, economizer, air preheaters, and lower slope at Rush Island Unit 1 ultimately cost approximately $34 million. Stevens Test. Tr. Vol 2A, 22:24-23:3; Golden Test., Tr. Vol. 8-A, 23:7-10.

178. Replacement of the reheater, economizer, and air preheaters at Rush Island Unit 2 ultimately cost more than $38 million. Stevens Test., Tr. Vol 2-A, 28:5-9; Golden Test., Tr. Vol. 8A, 23:7-10.

179. Ameren's budget for the Rush Island plant is divided into an Operation and Maintenance ("O&M") component and a Capital component. Stevens Test., Tr. Vol. 1-B, 89:23-90:3.

180. A capital project is one that would improve the value of the asset. Stevens Test., Tr. Vol. 1-B, 91:1-10.

181. The component replacements at issue in this case were capital projects. The projects were actually funded out of Ameren's capital budget rather than its O&M budget. Stevens Test., Tr. Vol. 1-B, 89:23-90:3, Vol. 2-A 5:12-17; Golden Test., Tr. Vol. 8-A, 23:14-15.

182. Costing $34 to $38 million, the boiler component replacements at Unit 1 and 2 were the costliest capital projects ever done at the Rush Island plant. Golden Test., Tr. Vol. 8-A, 23:7-19. By way of comparison, Rush Island's entire annual O&M budget for the Rush Island plant was about $25 million. Meiners Test., Tr. Vol. 7-B, 23:24-24:2.

183. The boiler component replacement projects were among the most expensive boiler projects that Ameren identified to EPA as ever having been undertaken at any of its plants. Knodel Test., Tr. Vol. 1-A, 81:9 – 82:8.

III. THE 2007 AND 2010 BOILER UPGRADES EACH RESULTED IN A SIGNIFICANT NET EMISSIONS INCREASE OF SO_2 WITHIN THE MEANING OF THE PSD REGULATIONS

184. The 2007 and 2010 boiler upgrades triggered PSD if: (1) Ameren should have expected them to result in a significant (i.e., more than a 40 tons-per-year) SO_2 increase; or (2) a 40 tons-per-year SO_2 increase related to the boiler upgrades actually occurred. *Ameren SJ Decision*; *see also* 40 C.F.R. § 52.21(a)(2)(iv)(*b*), (*c*).

185. As described further below, Ameren should have expected the 2007 and 2010 boiler upgrades to increase the availability of the units, thereby resulting in more than 40 tons per

year of increased SO_2 emissions. At both units, these availability improvements resulted from eliminating significant outages and derates that had been plaguing the boilers prior to the upgrades. Removing the problems that had been limiting their pre-project availability should have been expected to increase their post-project operations and emissions. In addition, for at least the 2010 boiler upgrade, Ameren should have expected the new economizer, reheater, and air preheaters to increase the maximum megawatt generating capability of the unit, resulting in increased annual emissions.

186. In addition, availability and hours of operation of Units 1 and 2 actually increased by an amount greater than that required to trigger PSD, just as Ameren expected, as did the megawatt capability of Unit 2.

187. Evidence for these expected and actual increases is found in Ameren's documents and project justifications, in its GADS and other operational data, and in the results of a computer modeling program called ProSym that Ameren uses to simulate the operations of its generating units. The United States' emissions experts, Mr. Koppe, Dr. Sahu, and Dr. Hausman, explained how this evidence demonstrates that the availability and capability improvements at Rush Island Units 1 and 2 would be expected to, and did, far exceed the 40 tons-per-year PSD threshold for $SO_{2.}$ After a brief overview, the specific evidence supporting a finding that the 2007 and 2010 boiler upgrades resulted in significant SO_2 increases is reviewed in further detail below.

A. Overview

188. The Rush Island units are low-cost, baseload units, meaning that they will operate any additional hours that they are made available to operate. FOF 6. As some of the most cost-effective units in a large and interconnected electricity supply system that is vastly larger than

any individual unit, it was not a lack of demand that was holding the units back prior to the 2007 and 2010 boiler upgrades. These "work horse" units were already made to run every hour they were available to run. What held the units back prior to their upgrades was the forced outages and load limitations that were plaguing the boilers as a result of burning a coal for which they were not designed, along with the fact that key boiler components had degraded as they neared the end of their design lives. Fixing those problems was expected to, and did, result in increased operations.

189. Because they lack SO_2 pollution controls, the Rush Island units are very large sources of air pollution. FOF 8, 9. The large size of the units means that very small changes in performance can result in increased SO_2 emissions of more than 40 tons per year.

190. For example, it only takes 21 additional hours of full power operation at either unit to produce more than 40 tons of SO_2. Sahu Test., Vol. 5, 41:3-7, 45:25-46:4. Given that it typically takes two to three days to recover from even a single outage (FOF 35), eliminating just one outage would result in more than 40 additional tons per year of SO_2. Sahu Test., Vol. 5, 46:17-47:2, 62:2-63:10, 94:5-95:23; August 15, 2005 Presentation (Ex. 332), at AM-00966775, 794 (showing *inter alia* that one outage due to the economizer lasts three days).

191. Measured in terms of equivalent availability, it takes only about a 0.3 percentage point (i.e., one-third of a percentage point) increase in availability to produce more than 40 additional tons per year of SO_2 from these units. Hausman Test., Tr. Vol. 4-B, 66:15-25.

192. Similarly, increasing the capability of Rush Island Unit 2 by just 1.7 megawatts would result in an increase in SO_2 emissions of at least 40 tons per year. Sahu Test., Vol. 5, 41:11-14; 46:5-11; Hausman Test., Tr. Vol. 4-B, 58:4-60:2 (one megawatt increase in capacity produces 23 additional tons of SO2).

B. GADS-Based Emissions Calculations for Rush Island Units 1 and 2

193. The United States presented emissions calculations utilizing data generated by Ameren which was transmitted to the North American Electric Reliability Council ("NERC") and maintained in NERC's Generating Availability Data System. As explained above in Subsection II.B.4, GADS is an industry-wide database that collects information on the performance of power plants and the effects that various problems have on that performance. Ameren and other utilities use GADS data to track the causes of outages and derates so that they can assess the status of plant equipment and predict future availability. FOF 89, 92. As also described above, Ameren specifically uses GADS data to calculate "lost generation" when performing financial calculations to determine whether to perform capital projects. FOF 103.

194. Plaintiff's expert Mr. Koppe, who has been a power plant performance consultant for four decades and helped develop the GADS database, reviewed Ameren's GADS data to determine which outages and derates were caused by problems with the boiler components at issue in this case. FOF 90, 91, 106.

195. Mr. Koppe then quantified the expected effect of the 2007 and 2010 upgrades on availability. In performing his analyses, Mr. Koppe used the same basic approach that he used to assess expected performance impacts in his work for utilities over the past 40 years. Koppe Test., Vol. 3-A, 35:6-9 ("I've seen it used by many different utilities, including Ameren, and I've seen it in various industry publications.")

196. Mr. Koppe concluded that the company should have expected, and did expect, the 2007 and 2010 boiler upgrades to eliminate all of the availability losses that were due to the economizers, reheaters, lower slopes, and air preheaters. Koppe Test., Vol. 3-A, 48:24-49:6; *see also* Sahu Test., Vol. 5, 95:24-97:2. Ameren's project justifications were based on this very

assumption. Koppe Test., Tr. Vol. 3-A, 49:24-51:14. *See* FOF 145, 146, 147. Similarly, the effects of pluggage on the units were expected to be eliminated for at least decades into the future. Koppe Test., Vol. 3-A, 54:16-55:3.

197. Based on Ameren's documents and data, and relying on his decades of experience in the industry, Mr. Koppe then made an engineering judgment on the improvements in availability that would be expected to result from the 2007 and 2010 boiler upgrades. In order to determine whether eliminating the causes of unavailability related to the components at issue would result in an overall increase in unit availability, Mr. Koppe assessed the condition of the rest of the equipment at Rush Island Units 1 and 2 in order to ensure that other problems would not be expected to offset the performance improvements expected from the boiler upgrades. As Mr. Koppe explained, the boiler components replaced by Ameren were the "things that were really hurting them" in terms of availability, as they alone were causing roughly half of all the lost productivity at the units during the baseline period. Koppe Test., Vol. 3-A, 47:7-12; 75:3-11. "[P]roblems with all the rest of the equipment were only half of the losses, and here you had four problems that were half of all the lost productivity." *Id*. 48:2-8. However, he wanted to be sure that "the level of maintenance that was being done" on the remaining parts of the unit that were not being upgraded was sufficient to maintain the overall very good level of performance that those remaining components had experienced. Koppe Test., Vol. 3-A, 56:12-56:25.

198. As part of this review of the entire unit, Mr. Koppe reviewed GADS data and other contemporaneous company data and documents describing the overall condition of the units. Mr. Koppe reviewed, for example, reports identifying all of the maintenance and capital projects done during the outage, unit condition assessments prepared by company engineers, and presentations made by plant engineers to management about the condition of the unit. Koppe

Test., Vol. 3-A, 34:13-21, 51:20-57:17; *see also* GADS Events Data (Pl. Ex. 925), 2007 and 2010 Outage Reports (Pl. Ex. 34 and 46), Condition Assessments (Pl. Ex. 106 and 606), and State of the System Presentations (Pl. Ex. 15, 41, and 111). Based on his review of this evidence, Mr. Koppe concluded that the overall effect of everything else at the plant on availability would not offset the availability gains from the components at issue. Koppe Test., Vol. 3-A, 51:20- 66:5-67:3.

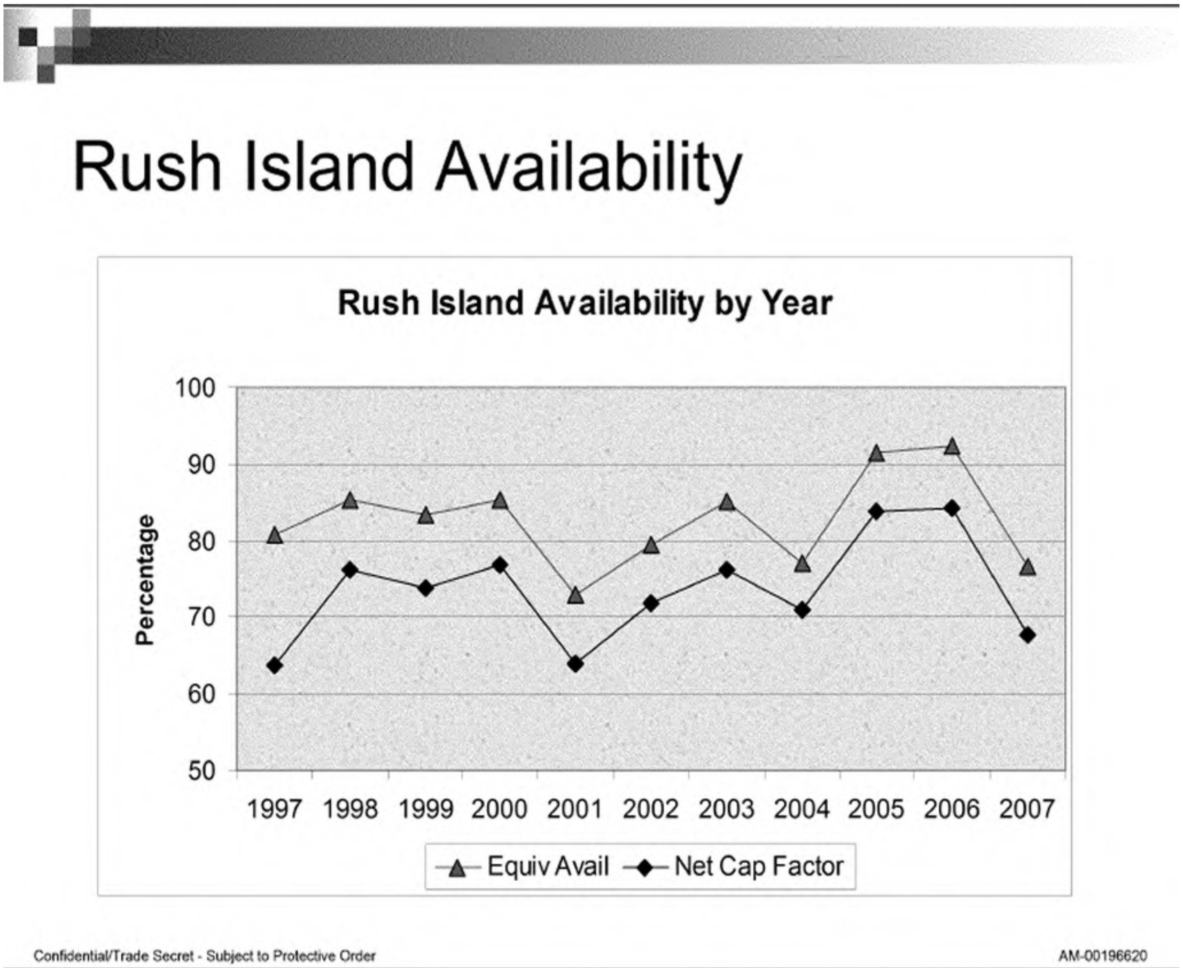
199. Evidence that other problems would not be expected to offset the performance improvements from the 2007 and 2010 boiler upgrades was also provided by Ameren witnesses at trial. As Mr. Naslund testified, as part of the new "super outage" concept that he championed, the company proactively addressed everything that might cause problems in the next six years at a unit to ensure the unit would run as well as possible and "improve unit availability." Naslund Test., Tr. Vol. 6-B 7:1- 8:6. After implementing the super outage process, forced outages in fact went down and availability went up. Naslund Test., Tr. Vol. 6-B, 6:19-25. Mr. Strubberg similarly testified that he was responsible for a condition-based maintenance program called the PRO/PMO program that helped keep the balance of individual components at high availability, and by doing that, it helped keep the units at high availability. Strubberg Test., Tr. Vol. 8-A, 35:21-23, 38:23-24, 39:21-25, 61:5-9, 77:8-12.

200. Once the expected impact on availability is determined for a unit, the next question is to determine whether that increased availability will actually be used to operate more in the future. Whether or not increased availability will result in an additional hour of operation in the future can sometimes be a "tricky question" for some units, "but it's not for these units, because these units operate for almost every single hour that they are able to operate. So if you increase the number of hours a unit is available to operate, that will result in an increase in the

number of hours the unit does operate." Koppe Test., Vol. 3-A, 35:17-26; *see also* Naslund Dep., Sept. 18, 2014, at 55:2-55:7.

201. This direct relationship between availability and generation at Rush Island was also confirmed by modeling performed by Dr. Hausman. As Dr. Hausman explained, if availability is improved, it means the unit can run more hours or it can run at a higher level for more hours. Hausman Test., Tr. Vol. 4-B, 39:9-13. For a relatively low-cost baseload unit, if it is able to produce more, it typically will produce more. As Dr. Hausman explained: "I think that's a fairly fundamental way to look at electricity markets. If I were to run a model and it ran less or used less fuel, there would be something very strange in that." Hausman Test., Tr. Vol. 4-B, 39:16–40:4; *see also id.* at 36:12–21. Dr. Hausman found exactly such a linear relationship between availability improvements and generation at Rush Island. Hausman Test., Tr. Vol. 4-B, 64:10-64:20, 71:7-25.

202. This direct relationship between availability and generation at baseload units like Rush Island was also obvious from presentations prepared by Ameren itself on the importance of availability, which showed availability tightly tracking plant generation. Strubberg Test., Tr. Vol. 8-A, 100:4-6, 100:15-17; 2008 State of the System (Pl. Ex. 15), at AM-00196620.



203. The data also shows a relationship between unit availability and SO_2 pollution, as Ameren's expert Michael King acknowledged at trial. King Test., Tr. Vol. 6-B, 86:2-23.

204. The extraordinarily high use of Rush Island's availability was also confirmed in the GADS data that Mr. Koppe reviewed, which included data on how often the units were placed in a status known as "reserve shutdown." When a unit is in reserve shutdown, it is available to operate but does not for economic reasons. Koppe Test., Tr. Vol. 3-A, at 36:22-37:1.

205. The Rush Island units did not spend a single hour in reserve shutdown during the PSD baseline periods. Koppe Test., Tr. Vol. 3-A, 37:2-7; Naslund Dep., Sept. 18, 2014, Tr. 54:21-55:7; RFA Nos. 189, 192, 193, 203. In the five years before the projects, one of the units operated every single hour it was available, and the other operated 99.9% of the time. Koppe Test., Tr. Vol. 3-A, 37:8-18. That means that if a Rush Island unit "is available to operate another hour, it will operate for that hour; and that, of course, requires burning more coal and generating more emissions." Koppe Test., Tr. Vol. 3-A, 37:19-24; Naslund Test. Vol. 6-A, 50:3-13 (describing Rush Island units as "two workhorses"), 45:3-20 (since 2005, the Rush Island units "were staying up on load at much higher levels around the clock"), 48:7-49:3 (because the Rush Island units are among the cheapest units in MISO, they run a higher percentage of time); Naslund Dep., Sept. 18, 2014, Tr. 55:4-7.

206. Mr. Koppe's quantification of increased unit availabilities caused by the 2007 and 2010 boiler upgrades was then translated into emissions increases by Dr. Sahu, a combustion engineer and environmental permitting engineer, who has performed PSD calculations hundreds of times. Sahu Test., Vol. 5, 34:24-38:14. Dr. Sahu did not assume that Ameren would generate at full capacity every additional hour that it generated. Instead, he applied the same utilization factor that the units experienced during the PSD baseline period. Sahu Test., Tr. Vol 5, 51:5-53:16, 75:3-77:20.

207. Using the same baseline utilization factor is consistent with the fact that the units are baseload units that are used whenever they are available. In addition, the historic utilization factor of the units remained relatively stable, and Ameren documents indicate that it expected the utilization factor of the units to remain relatively stable going forward. Sahu Test., Tr. Vol. 5

57:15-58:21; September 9, 2006 Email and attached critical review spreadsheet (Pl. Ex. 333), at Rush 1 and Rush 2 tabs.

208. Use of a constant utilization factor was also confirmed by Ameren's witnesses. Ameren expert Marc Chupka opined in his expert report that it "would be reasonable to assume a constant utilization factor for projecting future emissions at least for some period of time" after the projects at issue in this case. Chupka Test., Tr. Vol. 8-B, 77:3-18. Similarly, Sandra Ringelstetter's work papers identified the baseline utilization factor and the utilization factor projected by Ameren for both Unit 1 and Unit 2. For Unit 1, the utilization factor was projected to stay basically the same (a change of 0.09%), while for Unit 2 it was projected to increase by about 2%. Def. Ex. NE, at "RI U1 2007 Summary" and "RI U1 2010 Summary."

209. Using the same utilization factor from the baseline period specifically eliminates the impact of other factors that could cause an increase in utilization of a unit when its availability improves, thus isolating just the effect of the boiler upgrades. For instance, whereas Ms. Ringelstetter identified a 2% increase in utilization factor at Unit 2, Dr. Sahu's use of the baseline utilization factor excludes any effects of increased demand on the units by calculating just the increase that is due to the availability improvements made possible by the upgrades. Sahu Test., Tr. Vol. 5, 75:18-76:5, 153:21-25.

210. In addition, as Dr. Sahu described, the general approach of applying a utilization factor to calculate the additional generation from an expected availability improvement is consistent with Ameren's practices and is well understood in the industry. The same basic formula is found in Ameren's availability worksheets, which translate availability improvements into generation for fuel budgeting purposes, as well as industry documents such as a 1985 study publication of the Electric Power Research Institute ("EPRI"). Sahu Tr., Vol. 5, 53:17-57:5. For

instance, Ameren's availability worksheets provide the following formula for calculating "expected annual plant generation" from an availability change: "Total Net mwhrs" equals "Plant Equiv. Avail. X Utilization Factor." Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions." The 1985 EPRI study provides a similar formula. *See* Economic Evaluation of Plant-upgrading Investments (Pl. Ex. 241), at AME_RHK000011. Similarly, although Ameren has criticized Dr. Sahu's use of utilization factors as applied to both outages and derates in this case, Ameren itself uses utilization factors in a similar way outside of this litigation. For instance, in using a utilization factor to estimate future generation, Ameren's availability worksheets specifically defines the utilization factor as "the percent of mwhrs used after outages and derates." Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions."

211. Dr. Sahu's emission calculations also used the same SO_2 emission factor from the baseline period. As with holding the utilization factor constant, reasons for using the baseline emission factor in the calculation of post-change emissions include the fact that Ameren documents indicate that the emission factor was expected to remain fairly stable. Sahu Test. Tr. Vol. 58:22-59:24, 89:6-89:13, September 9, 2006 Email and attached critical review spreadsheet (Pl. Ex. 333), at Rush 1 and Rush 2 tabs.

212. In addition, the project justification documents for the 2007 and 2010 boiler upgrades made no mention of *any* expected improvements in the gross efficiency of the units, a point that was conceded by Ameren's capability expert. Caudill Test., Tr. Vol. Vol. 10-B, 44:24-45:12; *see also* Sahu Test., Tr. Vol. 5 108:3-21.

213. While Ameren argued that it expected small reductions in auxiliary load as a result of the boiler upgrades, such reductions would result in an improvement in net efficiency, not gross efficiency, and as a result do not affect the amount of coal that the unit is capable of

burning. Rather, they just mean that less power is used to run the plant, so more of the gross generation recovered by the boiler upgrades could be sent to the grid. Koppe Test., Tr. Vol. 3-B, 11:16-12:4; Shelton Test., Tr. Vol. 10-A, 85:8-10. As Dr. Sahu explained, all of his calculations are based on gross megawatts because gross is what relates to how much SO_2 comes out of the boiler. Sahu Test., Tr. Vol. 5 52:16-24, 84:20-24.

214. Similarly, while Ameren did expect some improvement in efficiency at Unit 2 due to the contemporaneous replacement of the low pressure turbine, Dr. Sahu accounted for that in his calculations by factoring out both the additional megawatt capability of the new turbine and the heat rate of the turbine. Sahu Test. Tr. Vol. 5 84:9 – 85:1, 135:23-136:8, 137:9-15; 138:3-10, 181:21 – 182:4. Dr. Sahu's treatment of the low pressure turbine on the expected SO_2 emission rate was consistent with how Ameren itself treated the expected effect of the turbine outside of this litigation. For instance, Ameren's financial analysis was based on the assumption that the turbine-related efficiency improvements would allow Unit 2 to produce more megawatts, but would not result in the unit burning any less coal. Pl. Ex. 48, at "Data Entry" sheet (rows 149-152, col. D (and comment box) (showing that Ameren did not include efficiency benefit inputs for "decrease in fuel usage")), Pl. Ex. 110, at AM-02465690; Koppe Test., Vol. 3-B, at 29:9-32:9. As Dr. Sahu noted, Ameren's financial analysis shows that there was no expected fuel decrease associated with the capacity increase. Sahu Test. Tr. Vol. 5, 97:3 - 99:4.

215. Use of a constant emission factor was also corroborated by the United States' other experts. As Dr. Hausman explained, when a baseload unit like the Rush Island units is modified to become more efficient, it allows the unit to generate more electricity while consuming the same amount of coal. Hausman Test., Tr. Vol. 4-B, 37:6–18. Because a baseload plant has essentially an unlimited market for its very low-cost power, if it becomes more

efficient, it will burn the same amount of coal but produce more energy than it can sell into the market. Hausman Test., Tr. Vol. 4-B, 38:7–11. As a result, as Mr. Koppe also explained, the separate efficiency gain from the turbine would result in increased megawatts but would not change the full load heat input to the boiler. Koppe Test., Tr. Vol. 3-B, 29:9-32:9. This was also consistent with Ameren employee Jeff Shelton's testimony that a more efficient turbine can allow a unit to make more megawatts with the same amount of heat input. Shelton Test., Tr. Vol. 10-A, 85:14-20, 85:5-9.

216. Finally, use of a constant emission rate was also borne out by Ameren's operating data as reported to EPA, which confirmed that the post-project emission rate at Unit 1 stayed relatively constant, and actually increased somewhat at Unit 2 as compared to the PSD baseline periods. Sahu Test., Tr. Vol. 5, 109:14-22. At Unit 1, reported heat rate deteriorated slightly, from 9,282 Btu/Kwh to 9,447 Btu/Kwh, and the unit emitted approximately 21 more pounds per hour of SO_2 than it had in the baseline. Sahu Test., Tr. Vol. 5 110:6-111:6; Knodel Test., Tr. Vol. 1-A, 110:8-24. At Unit 2, reported heat rate deteriorated from 8,800 Btu/Kwh to 9,676 Btu/Kwh, and the unit emitted approximately 456 more pounds per hour of SO_2 than it had in the baseline. Knodel Test., Tr. Vol. 1-A, 111:8-20. Sahu Test. Tr. Vol. 5, 112:21-24. As a result, for every additional hour that Rush Island Units 1 and 2 were able to operate in the post project period, they actually emitted more SO_2 per hour.

217. Because Dr. Sahu's calculation is based on the incremental impact of the projects on unit performance calculated by Mr. Koppe, his entire predicted increase is related to the project. Sahu Test., Tr. Vol. 5, 49:21 – 50:3, 60:13-18, 61:15-17, 73:6 – 74:4, 77:11-20, 84:15 – 87:10.

218. Ameren presented testifying expert Michael King to critique the approach used by Mr. Koppe and Dr. Sahu. But Mr. King agreed that Mr. Koppe and Dr. Sahu "have the appropriate experience to estimate the effect of modifying a power plant on generation [and] emissions." King Test., Tr. Vol., 6-B, 65:17-21.

219. Another Ameren testifying expert, Marc Chupka, conceded that the method used by Mr. Koppe and Dr. Sahu for determining PSD emissions increases has at least been "well-known in the industry" since the first enforcement cases were filed in 1999. Mr. Koppe testified that he and Dr. Sahu had used the same basic formula in this case that he and other utilities have used for decades. Koppe Test., Tr. Vol. 3-A, 35:6-9; *see also* Sahu Test., Tr. Vol. 5, 53:17-57:5 (discussing Ameren and industry documents). Mr. Chupka himself has been asked to analyze utility projects using the same method employed by Mr. Koppe and Dr. Sahu numerous times. Chupka Test., Tr. Vol. 8-B, 74:14-21, 75:5-10.

1. Results of projected emissions increase calculations based on the GADS data at Rush Island Unit 1

220. As described further below, Ameren should have expected an increase of at least 600 tons per year of SO_2 emissions over the PSD baseline emissions as a result of the availability improvements caused by the 2007 boiler upgrade.

221. The PSD "baseline" period used by Ameren for Unit 1 in this litigation was the highest 24-month period of emissions in the five years before the 2007 boiler upgrade, which was February 2005 through January 2007. During that period, Unit 1 emitted 14,874 tons per year of SO_2. Sahu Test., Tr. Vol. 5, 49:8-20; Knodel Test., Tr. Vol. 1-A, 95:6-25.

222. During this baseline period, problems in the economizer, reheater, lower slopes, and air preheaters caused Unit 1 to lose 336.1 equivalent full power hours of generation per year,

which is roughly equivalent to 14 days of operation per year. Koppe Test., Tr. Vol. 3-A, 45:15-46:24. The unit was completely shut down in outages for 246.4 hours per year due to problems in the components at issue and lost the equivalent of another 89.7 full power hours of operation due to deratings. *Id.*

223. As explained by Mr. Koppe, the problems associated with the Unit 1 reheater, economizer, air preheater, and lower slopes caused about 50% of all the availability losses at Unit 1 during the baseline period. Koppe Test., Tr. Vol. 3-A, 47:7-12; 48:2-8.

224. These problems reduced Unit 1's availability during the baseline period by 3.8 percentage points. Sahu Test., Tr. Vol. 5, 63:11-64:5. Unit 1's availability was 92.1% during the baseline. Koppe Test., Tr. Vol. 3-A, 48:9-11. The average annual availability of Unit 1 over the entire five-year pre-project period was 87.5%. *Id.* 48:15-23

225. Based on his analysis of Ameren's operating data, including GADS, as well as contemporaneous documents, Mr. Koppe concluded that Ameren should have expected the 2007 boiler upgrade to eliminate all of the availability losses in the baseline period related to problems in the reheater, economizer, lower slopes, and air preheater components. Koppe Test., Tr. Vol. 3-A, 48:24-49:6, 66:5-12; *see also* Sahu Test., Tr. Vol. 5, 95:24-97:2.

226. Company documents and witnesses confirm that Ameren actually had such an expectation. Ameren expected that as a result of the 2007 boiler upgrade, availability losses attributable to the replaced components would be completely eliminated for years in the future. Meiners Test., Vol. 7-B, 40:1-18 ("Q. Right. If you do the project, in the future you won't have those causes of unavailability, right? A. Correct."); Boll. Test., Vol. 8-B, 46:11-47:10 ("that's probably a good bet"); FOF 145, 146, 147.

227. Based on his review of company documents and data, as well as his experience in the industry and his assessment of the overall condition of the rest of the unit, Mr. Koppe concluded that Ameren should have expected that the 2007 boiler upgrade would result in a substantial increase in the overall equivalent availability of Rush Island Unit 1. Koppe Test., Tr. Vol. 3-A, 34:13-21, 51:20-55:17, 66:5-12. The impact of the project alone would be to increase the availability of Unit 1 by 3.8 percentage points over baseline availability by eliminating all 336.1 EFPH of availability losses related to the reheater, economizer, lower slopes, and air preheater. Koppe Test., Tr. Vol. 3-A, 48:24-49:6; *see also* Sahu Test., Tr. Vol. 5, 95:24-97:2. If the four components had not been replaced, the availability of the unit would have been expected to decrease. Koppe Test., Tr. Vol. 3-A, 66:13-67:3.

228. Similar projected increases can be found in Ameren's availability forecasts. For example, the forecast for the 2006 Fuel Budget projected that Unit 1's long-term average availability would be 95.0% as a result of the "boiler improvements" done during the Unit 1 outage. This represents an increase of 7.5% over Unit 1's five-year pre-project average and about a 3% increase over Ameren's high baseline emissions period (a 3 percentage point improvement is the equivalent of about 10 more days of operation). Koppe Test., Tr. Vol. 3-A, 61:20-65:8; Meiners Test., Vol. 7-B, 39:16-25; September 23, 2005 Email (Pl. Ex. 214); September 28, 2005 Email attaching Availability Worksheet (Pl. Ex. 215), at Rush tab.

229. Ameren's 2006 Fuel Budget forecast showed a 4.2 percentage point improvement in Unit 1's forced outage rate after the work. Def. Resp. to Interrogatory No. 68; Boll Test., Vol. 8-B, 42:19-44:1. Ameren's Rule 30(b)(6) witness, David Boll, admitted in deposition testimony that the 4.2% improvement in the outage rate was "most probably due to the major outage" and could provide no other reason for the improvement. Boll Test., Tr. Vol. 8-B, 44:2-45:5; Boll

Dep. Dec. 12, 2013, Tr. 122:13-123:2; Aug. 17, 2007 Email and Attached Spreadsheet (Pl. Ex. 523), AM-02264672.

230. Similarly, Rush Island Plant Manager Robert Meiners gave a presentation to Ameren senior executives in which he discussed the condition of the reheater, economizer, air preheater, and lower slopes on Rush Island Unit 1 and the efforts to replace those components. At the end of the presentation, Mr. Meiners presented a graph showing that Rush Island's long-term availability would increase by almost 5 percentage points, from about 90% in 2005-2006 to 95% after both outages had been completed. Mr. Meiners admitted that even a one percent change in availability would be a significant change. Meiners Test., Tr. Vol. 7-A, 68:8-18; Tr. Vol. 7-B, 27:21-24, 28:10-20, 31:15-21, 33:4-6; Rush Island Business Plan Presentation (Pl. Ex. 126), at AM-02625397.

231. Before the Unit 1 project had been approved, Ameren was not forecasting an increase in availability; instead its forecasts were that availability would remain flat – 91%. That is because all of the other work done during the 2007 outage would maintain availability but would not cause an increase in availability. Koppe Test., Tr. Vol. 3-A, 65:13-66:4, 66:13-67:3.

232. Based on Mr. Koppe's availability analysis, and consistent with his review of company data and documents, Dr. Sahu translated the increased operations that were expected to result from the 2007 boiler upgrade into emissions and determined that the expected SO_2 increase from such operations was far more than 40 tons per year. Sahu Test., Vol. 5, 39:23-25, 40:21-24, 102:7-10, 113:22 – 114:1. Specifically, Dr. Sahu calculated that Ameren should have expected a net emissions increase of 607.8 tons per year of SO_2 over the PSD baseline emissions as a result of the replacement of the economizer, reheater, lower slopes, and air preheater. Sahu Test., Tr. Vol. 5, 49:8-50:14, 57:15-59:5, 92:22-93:17; 115:17-20.

233. Even without counting the effects of derates and focusing just on the outages caused by the components, the 2007 boiler upgrade would allow the unit to operate 246 more hours or about 10 more days per year by eliminating the outages associated with the reheater, economizer, lower slopes, and air preheaters. By itself, this would cause a more than 400 ton-per-year increase in emissions of SO_2. Koppe Test., Tr. Vol. 3-A, 49:12-23; Sahu Test., Vol. 5, 65:12-66:22.

2. Rush Island Unit 1 actual emission increases

234. Just as Ameren expected, Unit 1 experienced a substantial increase in availability following the 2007 boiler upgrade. In 2008, Rush Island Unit 1 had an equivalent availability of 96.77%. This was the highest equivalent availability of any unit in the entire Ameren system in 2008. Unit 1's equivalent availability in 2008 was higher than any 24-month period of equivalent availability since the Rush Island plant first began tracking availability data in 1982 and higher than any 12-month period since 1990. Anderson Test., Tr. Vol. 7-A 55:8-17, 56:22-58:2; Meiners Test., Tr. Vol. 7-B, 49:9-15, 55:18-23, 56:12-16; Strubberg Test., Tr. Vol. 8-A, 94:3-8, 95:1-4; Def. Resp. to RFA 299; Jan. 9, 2009 Email (Pl. Ex. 104), at AM-02272427 ("Rush Island 1 had the highest EAF [equivalent availability factor] at 96.77%"); *see also* Koppe Test., Tr. Vol. 3-A 67:4-69:3.

235. Rush Island Plant management received significant salary bonuses relating the Rush Island's availability in the year 2008, whereas they had received no such bonuses for the year before. Strubberg Test., Vol. 8-A, 100:23-102:3; Def. Response to Interrogatory No. 65.

236. In April 2009, Rush Island Unit 1 set an "all-time record run for days on line," breaking the "old plant record of 211 days [that] was set in 1990." April 7, 2009 Email re: "Rush Island Unit 1 Record Run" (Pl. Ex. 105), at AM-02276058; Strubberg Test., Tr. Vol. 8-A,

60:7-61:18 (admitting that Unit 1 had an equivalent availability of more than 98% during this period). Ameren Vice President Mark Birk specifically called out the replacement of the "reheater, economizer, and lower slopes" in 2007 as having "paid off" when he reported Unit 1's record availability to Ameren's CEO Warner Baxter. April 7, 2009 Email re: "Rush Island Unit 1 Record Run" (Pl. Ex. 105), at AM-02276058; *see also* Koppe Test., Tr. Vol. 3-A 69:12-70:12.

237. The GADS data confirmed that the cause of the improved availability was the improved performance of the components at issue that were replaced as part of the 2007 boiler upgrade. As Ameren should have expected, and did expect, all of the availability losses due to problems in the reheater, economizer, lower slopes, and air preheater were eliminated after the 2007 boiler upgrade. As a result, component-related availability losses were reduced from 336.1 EFPH per year to zero. Availability losses due to everything else also decreased slightly. Koppe Test., Tr. Vol. 3-A, 70:17-71:2, 81:8-17; Sahu Test., Tr. Vol. 5, 64:8-21.

238. Further reflecting the actual performance improvements resulting from the 2007 boiler upgrade, Ameren's reported GADS data further show that Unit 1's equivalent availability actually increased over the baseline period by 4.3 percentage points, from 92.1% to 96.4% in the relevant post-project period. *Id.*; Sahu Test., Vol. 5, 64:24-65:3; Koppe Test., Tr. Vol. 3-A, 71:18-72:14.

239. None of the availability improvements that actually occurred at Unit 1 would have happened if the reheater, economizer, lower slopes, and air preheater had not been replaced. Koppe Test., Tr. Vol. 3-A, 66:13-67:3; Meiners Test., Vol. 7-B, 57:11-16.

240. Similarly, Ameren's reported GADS data shows that Unit 1's operating time increased from 8,208 hours per year in the baseline to 8,568 hours per year during the highest post-project period of emissions, for an increase of 360 hours. This increase in operating hours

included the effect of eliminating the 246 outage hours per year during the baseline period that were caused by problems associated with the reheater, economizer, lower slopes, and air preheater. Koppe Test., Tr. Vol. 3-A, 73:3-15; Sahu Test., Tr. Vol. 5, 65:12-66:22, 109:7-13.

241. There is no question that these increased hours of operation were accompanied by more heat input. Annual heat input increased from 43,957,163 MMBtu per year in the baseline period to 45,442,171 MMBtu per year in the relevant post-project period. Sahu Test., Vol. 5, 109:25-110:5.

242. Similar increases are shown in Ameren's certified Continuous Emissions Monitoring System ("CEMS") data, which show that Unit 1 operated more hours and emitted more pollution per hour during the relevant post-project period as compared to the baseline period. The CEMS data show that Unit 1's operating time increased by 320 hours per year, from 8,278 hours per year in the baseline to 8,598 hours per year in the applicable post-project period. Furthermore, when it was operating, Unit 1 emitted 21 more pounds per hour of SO_2 than it had in the baseline (increasing from 3,593 pounds per hour in the baseline to 3,614 pounds per hour in the post-project period). Knodel Test., Tr. Vol. 1-A, 109:7-16, 110:8-111:7, 112:14-24.

243. Ameren's CEMS data also show that in 2008, the first calendar year after the 2007 boiler upgrade, Rush Island Unit 1 emitted more SO_2 than it had in any year since 1995. Knodel Test., Tr. Vol. 1-A 82:9-19. During the relevant post-project period, Unit 1 emitted 15,539 tons per year of SO_2, which is 665 tons per year more than Unit 1 actually emitted during the baseline period. Sahu Test., Tr. Vol. 5, 49:8 – 20, 111:7-16; Knodel Test., Tr. Vol. 1-A, 95:6-25.

244. Eliminating 246 outage hours by replacing the reheater, economizer, lower slopes, and air preheater, by itself, equates to SO_2 emissions of more than 400 tons per year. Sahu Test.,

Tr. Vol. 5, 41:3-7, 45:25-46:4, 65:12-66:22. Because all of the availability losses caused by the reheater, economizer, and air preheater in the baseline were eliminated (336 EFPH and 246 outage hours), (Koppe Test., Vol. 3-A, 67:7-73:19), it is clear that at least 40 tons of the overall 665 ton increase in actual emissions is related to the increased equivalent availability and additional operating hours enabled by the replacement of these components. Sahu Test., Tr. Vol. 5, 39:13-17, 64:6-66:22.

3. Results of projected emissions increase calculations based on the GADS data at Rush Island Unit 2

245. As described further below, Ameren should have expected an increase of approximately 400 tons per year of SO_2 emissions over the PSD baseline emissions as a result of the availability improvements caused by the 2010 boiler upgrade.

246. The PSD "baseline" period used by Ameren for Unit 2 in this litigation was the highest 24-month period of emissions in the five years before the 2010 boiler upgrade, which was April 2005 through March 2007. During that period, Unit 2 emitted 14,287.7 tons per year of SO_2. Sahu Test., Tr. Vol. 5, 72:17-73:5; Knodel Test., Tr. Vol. 1-A, 91:4-17.

247. During this baseline period, problems in the economizer, reheater, and air preheaters caused Unit 2 to lose approximately 245 equivalent full power hours of availability per year. The unit was completely shut down in outages for 145.5 hours per year due to problems in the components at issue and lost the equivalent of another approximately 100 full power hours of operation due to deratings. Koppe Test., Tr. Vol. 3-A, 74:7 – 75-2; Sahu Test., Tr. Vol. 5 78:20-79:19.

248. These problems reduced Unit 2's equivalent availability during the baseline period by 2.8 percentage points. Sahu Test., Tr. Vol. 5, 119:6-17; Koppe Test., Tr. Vo. 3-A

76:17-22. According to the company's GADS events data, Unit 2's availability was 94.5% during the baseline. The average annual availability of Unit 2 over the entire five-year pre-project period was about 92%. Koppe Test., Vol. 3-A, 75:3-75:23, 76:17-22.

249. The problems associated with the Unit 2 reheater, economizer, and air preheaters caused about 50% of all the availability losses at Unit 2 during the baseline period. Koppe Test., Tr. Vol. 3-A, 75:3-11; Sahu Test., Tr. Vol. 5, 79:20-80:12.

250. Based on his analysis of Ameren's operating data, including GADS, as well as other company documents, Mr. Koppe concluded that, just as at Unit 1, Ameren should have expected the 2010 boiler upgrade to eliminate all of the availability losses in the baseline period related to problems in the reheater, economizer, and air preheaters. Koppe Test., Vol. 3-A, 76:23-77:5.

251. As at Unit 1, based on his review of company documents and data, as well as his experience in the industry and his assessment of the overall condition of the rest of the unit, Mr. Koppe concluded that Ameren should have expected that the 2010 boiler upgrade would result in a substantial increase in the overall equivalent availability of Rush Island Unit 2. Koppe Test., Vol. 3-A, 34:7-21, 55:4-57:22, 73:25-74:2, 77:9-79:14, 84:4-13. The impact of the project alone would be to increase the availability of Unit 2 by 2.8 percentage points over baseline availability by eliminating all 243 EPFH of availability losses related to the reheater, economizer, and air preheaters. Koppe Test., Vol. 3-A, 76:23-77:8.

252. Similar projected increases can be found in Ameren's project documents and availability forecasts, which indicate that Ameren should have expected and did expect that Unit 2's equivalent availability would be similar to what Unit 1 achieved after the 2007 boiler upgrade. Koppe Test., Tr. Vol. 3-A, 77:9-20; Meiners Test., Tr. Vol. 7-B, 50:14-51:2.

253. For instance, Ameren updated its financial justification for the Unit 2 outage in 2009, and included in that justification was the expectation that Unit 2's availability would be as high as Unit 1's availability was in 2008 – almost 97%. Koppe Test., Tr. Vol. 3-A, 77:21-78:19; Meiners Test., Tr. Vol. 7-B, 45:8-25, 48:4-49:5, 50:14-51:2; Unit 2 ELT Progress Report, (Pl. Ex. 110), at AM-02465690; Updated Financial Analysis (Pl. Ex. 48), at "Data Entry" tab (row 155, col. F (and hidden comment: "4.3% gain related to outage work (u2 vs. u1)"). That would be a 4.3 percentage point improvement in equivalent availability over what Unit 2 had experienced in 2008, and would represent about 15 additional days of operation for Unit 2. *Id.*; Meiners Test., Vol. 7-B, 18:22-19:16 (the EAF input in the analysis was the equivalent of "15 days of generation").[2] Mr. Meiners personally assured Ameren's CEO Warner Baxter that inputs used in the updated financial analysis for the Unit 2 outage were accurate. Meiners Test., Tr. Vol. 7-B, 46:9-47:11; May 16, 2009 Email (Pl. Ex. 347), at AM-02637756 ("I do believe the model is now a much more accurate representation of the economic benefits.").

254. Unit 1's availability in 2008 was 96.77%. During the same year, Unit 2's availability was 92.42%. RFAs 299 and 300; Anderson Test., Tr. Vol. 7-A, 55:8-17, 56:22-58:2; Meiners Test., Tr. Vol. 7-B, 49:9-20.

255. All or essentially all of the 4.2 percentage point improvement was related to the components at issue. All of the other work done during the outage was done to keep the performance of the rest of the unit from getting worse but would not improve availability. Koppe Test., Vol. 3-A, 78:23-79:6; Koppe Test., Tr. Vol. 4-A, 99:22-100:2, 103:14-104:25; *see also* Meiners Test., Tr. Vol. 7-B, at 57:11-16 (none of the availability improvement would have

[2] As discussed above, the final EAF input was adjusted downward by 0.1%, from 4.3% to 4.2%, as result of eliminating the lower slope replacement from the final scope of the project. FOF 148.

occurred if the components at issue had not been replaced); February 6, 2007 Email (Pl. Ex. 103) ("In reality, until we have the economizer replacement, Unit 2's forced outage is going to get worse, not better.").

256. Ameren's updated Full Work Order Authorization for the reheater and economizer replacements similarly indicated that Ameren expected the "boiler modifications [to] result in an improved operation of the unit that is at least equal to, if not better, than that currently expected with Unit 2 which had similar modifications in 2007." The authorization quantified this amount as an expected "3-4% improvement in the equivalent availability of the unit." October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; Birk Dep., Sept. 24, 2013, Tr. 194:1-195:13. Mr. Meiners confirmed that the availability input used for the justification was almost 97%. Meiners Test., Tr. Vol. 7-B, 50:14-51:2.

257. Ameren also should have expected Unit 2's long-term average equivalent availability to increase from 92% to 95%. Because there is a 2-3% variation in long-term forecasts, Ameren understood that Unit 2's highest annual availability after the 2010 boiler upgrade would be 97-98%. Koppe Test., Tr. Vol. 3-A, 76:17-22, 79:7-14; Meiners Test., Tr. Vol. 7-B, 54:14-55:6; Hausman Test., Tr. Vol. 4-B, 65:9–19. Other forecasts done before the boiler upgrade also predicted greater than 95% as a long term availability after the Unit 2 outage. *See* Updated 2008 Fuel Budget forecast (Pl. Ex. 252) (projecting 97% EAF for Unit 2 after outage); Meiners Test, Vol. 7-B, 51:18-52:7.

258. Based on Mr. Koppe's availability analysis, and consistent with his review of company data and documents, Dr. Sahu translated the increased operations that were expected to result from the 2010 boiler upgrade into emissions increases, and determined that the expected SO_2 increase from such operations was far more than 40 tons per year. Sahu Test., Tr. Vol. 5,

39:23-25, 40:21-24, 78:13-19, 99:13-100:11, 102:7-10, 113:22 – 114:1. Specifically, Dr. Sahu calculated that Ameren should have expected a net emissions increase of 414.5 tons per year of SO_2 due solely to the improvements in equivalent availability that Ameren should have expected from the replacement of the economizer, reheater, and air preheater. Sahu Test., Tr. Vol. 5, 73:6-74:14, 115:17-20.

4. Rush Island Unit 2 actual emission increases based on availability

259. Just as Ameren expected, Unit 2 experienced a substantial increase in availability following the 2010 boiler upgrade. During the relevant post-project period, as Ameren should have expected and did expect, there were no availability losses at all due to the reheater, economizer, and air preheater. Availability losses due to all the rest of the equipment at the unit essentially stayed the same. Koppe Test., Tr. Vol. 3-A, 80:7-23; Sahu Test., Tr. Vol. 5, 80:13-81:1, 82:13-83:5; *see also* Pl. Ex. 746 (work paper showing no GADS events for reheater, economizer, and air preheater during post-project period).

260. Overall equivalent availability increased by 2.9 percentage points, from 94.5% in the baseline to 97.4% during the first 12 months after the 2010 boiler upgrade, the relevant post-project period in the case. Unit 2's equivalent availability during this period was higher than any 24-month period in the history of the plant, going back to when Ameren first began tracking availability data in 1982, and higher than any 12-month period since 1987. Koppe Test., Tr. Vol. 3-A, 88:24-89:6; Anderson Test., Tr. Vol. 7-A, 58:3-9, 58:24-59:13; *see also* Sahu Test., Tr. Vol. 5, 81:2-15; Pl. Ex. 746.

261. Ameren's witness, Scott Anderson, referred to the increase in Unit 2's availability before and after the 2010 outage as "night and day." Anderson Test., Tr. Vol. 7-A, 58:7-9 (It is "obvious that the plant went way too long without a planned outage before correcting the

problems that it had. I mean, it's night and day."). Ameren had specifically called Mr. Anderson to discuss what the GADS data showed about the availability of the Rush Island units. Anderson Test., Tr. Vol. 7-A, 31:23-32:19.

262. None of the availability improvements at Unit 2 would have occurred if the reheater, economizer, and air preheater had not been replaced. Koppe Test., Tr. Vol. 3-A, 66:13-67:3; Meiners Dep., Tr. Vol. 7-B, 57:11-16.

263. According to Ameren's GADS data, Unit 2's operating time increased from 8,408 hours/year in the baseline period to 8,583 hours/year in the applicable post-project period, for an increase of 175 hours per year. This increase in operating hours included the effect of eliminating 146 outage hours per year in the baseline period caused by problems associated with the reheater, economizer, and air preheater. Sahu Test., Vol. 5, 83:8-22, 112:6-11, 158:3-8; Koppe Test., Vol. 3-A, 83:20-84:3; *see also* Koppe Test., Tr. Vol. 4-A, 115:18-25 (If "half of all the outage time that's occurring is eliminated by the projects and the effect of all the other equipment in the unit stays the same, … then the availability of the unit as a whole increases, and it increases specifically because the projects have eliminated boiler tube leaks in these sections and have eliminated the effects of pluggage.").

264. There is no question that these increased hours of operation were accompanied by more heat input. Annual heat input increased from 42,326,578 MMBtu per year in the baseline period to 47,660,058 MMBtu per year in the post-project period. Sahu Test., Tr. Vol. 5, 112:17-20.

265. Similar increases are shown in Ameren's certified CEMS data, which show that Unit 2 operated more hours and emitted more pollution per hour during the relevant post-project period as compared to the baseline period. The CEMS data show that Unit 2's operating time

increased by 123 hours per year, from 8,478 hours per year in the baseline to 8,601 hours per year in the applicable post-project period. Furthermore, when it was operating, Unit 2 emitted 456 more pounds per hour of SO_2 than it had in the baseline (increasing from 3,371 pounds per hour in the baseline to 3,827 pounds per hour in the post-project period). Knodel Test., Tr. Vol. 1-A, 109:7-16, 111:8-20, 112:3-10, 113:1-21.

266. Ameren's CEMS data also show that in 2011, the first calendar year after the 2010 boiler upgrade, Rush Island Unit 2 emitted more SO_2 than it had in any year since 1995. Knodel Test., Tr. Vol. I-A 82:9-19. During the applicable period of highest post-project emissions, Unit 2 emitted 16,458.1 tons per year of SO_2, which is 2,171 tons per year more than Unit 2 actually emitted during the baseline period. Sahu Test., Tr. Vol. 5, 74:15-18, 78:9-12, 112:25-113:3; Knodel Test., Tr. Vol. 1-A, 97:11-98:5.

267. Because all of the availability losses and outage hours caused by the reheater, economizer, and air preheater in the baseline were eliminated (243 EFPH and 146 outage hours), and it only takes an additional 21 hours of operation for Rush Island Unit 2 to emit 40 tons of SO_2, at least 40 tons of the overall increase in emissions at Unit 2 are related to the increased equivalent availability and operating hours enabled by the replacement of these components. Sahu Test., Tr. Vol. 5, 80:13-84:4, 115:10-116:4, 165:15-25.

C. Emissions Increases Based on Unit 2 Capability Analyses

268. In addition to improving the availability of both units, the 2010 boiler upgrade should have been expected to increase the capability of Rush Island Unit 2. As described further below, because Unit 1 experienced a capability increase after the 2007 boiler upgrade, Ameren should have expected – and did expect – a similar increase to occur after the 2010 boiler upgrade at Unit 2. Koppe Test., Tr. Vol. 3-B, 19:20-25.

1. The expected capability and efficiency impact of the Unit 2 boiler upgrade

269. In October 2007, Ameren engineers noted that Unit 1 had experienced an increase in capability due to the boiler component replacements, and Rush Island Supervising Engineer Gregory Vasel asked the Plant's Performance Engineer James Bosch to quantify that increase: "I looked at the 2006 [project justification] for the U2 economizer, reheater, and lower slope, and it projects *no* increase in capacity. I asked Mr. Bosch to quantify the capacity increase we've realized on U1, as well as the aux power reduction we're seeing with running one of our ID fans in low speed. … I communicated this to Leo Reid, who is working on the [project justification] for Bob Schweppe." Vasel Email (Pl. Ex. 130), at AM-02635983 (emphasis in original); Koppe Test., Tr. Vol. 3-B, 12:17-13:4.

270. Mr. Bosch reviewed full load tests from before and after the Unit 1 outage and determined that there had been a 19 MW increase in Unit 1's gross capability (from 611 MW to 630 MW). Pl. Ex. 130, at AM-02635983. Ameren project engineer Leo Reid incorporated a "16MW increase in generating capacity" into an updated financial analysis for the Unit 2 project. *Id*. at AM-02635982. In assessing what caused the capacity increase, Mr. Vasel instructed Mr. Bosch to look at the "delta P reductions of the [air preheater] vs. ([reheater] + economizer) …" *Id*. at AM-02635981. The updated financial analysis was provided by Mr. Vasel to Ameren's Director of Power Operations Robert Meiners, and was described as the "best information" that the plant had at the time. *Id*.

271. Mr. Koppe reviewed Ameren's full load tests and Plant Information data ("PI data") for Unit 1 and confirmed Mr. Bosch's analysis showing a 19 megawatt increase in capability had occurred at Unit 1. Mr. Koppe also reviewed the Plant Information data and other company documents and confirmed that there was a "dramatic drop" in the differential pressures

in the air preheater and economizer after the Unit 1 boiler upgrade. For example, a graph presented in Ameren's 2008 State of the System meeting indicates a "tremendous reduction" in the air preheater delta P from 14 to 5 inches of water. An air preheater delta P of 14 inches is "extremely high," and a reduction to 5 inches shows that Unit 1's capability was no longer limited by the effects of pluggage. Koppe Test., Vol. 3-A, 22:13-25:4; Vol. 3-B, 13:5-23; 2008 State of the System, Pl. Ex. 15, at AM-00196909; *see also* Sind Test., Vol. 9-B, 26:16-18 (air preheater differential pressures above 11 inches are "extremely high"); Cardinale Dep., July 31, 2014, Tr. 84:3-21; *see* FOF 75, 76 (showing graphs).

272. Ameren subsequently increased Unit 1's capability rating to 630 MW gross. Mr. Bosch reported the results of his quantification of a 19 MW increase in an email dated November 1, 2007. Vasel Email (Plaintiff's Exhibit 130), at AM-02635983. The document officially revising the 2008 capability stated that the increase was based on plant staff's request to reflect performance improvements following the spring 2007 outage during which the reheater, economizer, and air preheaters were replaced. Shelton Test., Tr. Vol. 10-A, 89:10-23.

273. In February 2008, Rush Island Plant Manager David Strubberg gave a presentation at a State of the System meeting in which he discussed the "Future Priorities" for Rush Island. Among the priorities discussed by Mr. Strubberg was a "25-30 MW" capability increase expected as a result of the boiler component and air preheater replacements and a separate 13 MW capability increase expected due to the replacement of the LP turbine. 2008 State of the System (Pl. Ex. 15), at AM-00196628; Koppe Test., Vol. 3-B, at 24:2-25:2.

274. A few months later, in June 2008, Rush Island Superintendent of Operations Andrew Williamson was asked by Ameren's Dispatch Coordinator Steve Schoolcraft to estimate the predicted capability of Unit 2 following the outage. Mr. Williamson noted: "We did

experience a substantial increase on Rush 1 due to increased boiler performance with the new RH/Econ/APHs and should reasonably expect the same for Rush 2." June 2008 Email (Pl. Ex. 267), at AM-02660313. Mr. Williamson predicted that Unit 2's capability would be 625 MW (net), which is about 655 MW (gross), after the outage. Of this, Mr. Williamson predicted that the boiler component replacements at issue, alone, would increase Unit 2's capability to 615 MW (net), or roughly 645 MW (gross), and replacement of the low pressure turbine would add another 12-15 MW. *Id*. at AM-02660307-08; Koppe Test., Tr. Vol. 3-B, 25:3-26:11; Williamson Test., Tr. Vol. 9-B, 40:10-41:2, 41:7-42:1.

275. Later in 2008, Mr. Williamson's prediction that Unit 2 would be able to achieve 625 MW (net) after the work was incorporated into Ameren's 10-Year System Plan, and represented an increase of 44 MW over the capability of Unit 2 at the time. This was the only increase in capability across the entire Ameren system noted in the 10-Year Plan. 10 Year Plan Spreadsheet (Pl. Ex. 251), at "UE" tab (hidden comment to row 20, col. F: "Rush Island unit 2 net output is increased from 581 to 625 (44 MW increase) provided by Steve Schoolcraft"), and "UE Changes" tab (row 54: "Rush Island 2's net output were changed to 625 MW per the plant's request …"); Koppe Test., Tr. Vol. 3-B, 26:16-27:6.

276. As described above, in 2009, Ameren completed an updated financial analysis for the Unit 2 outage. In addition to improvements in equivalent availability, Ameren's updated analysis included a 22.5 MW "projected annual increase … in plant capacity" as a result of the replacement of the reheater, economizer, and air preheater. Financial Analysis for Unit 2 (Pl. Ex. 48), at "Data Entry" Sheet, row 147, col. B & E; Koppe Test., Tr. Vol. 3-B, 28:2-12, 30:4-32:23.

277. The capacity increase input in the financial analysis was based on Ameren's estimate that replacing the economizer, reheater, and air preheater would allow Unit 2 to produce

30 more MW of capacity during the summer and 20 more MW for the rest of the year. The capability benefits were based on the combined effect of all three component replacements, and represented an increase over what Unit 2 was able to achieve during the pre-project period. Koppe Test., Tr. Vol. 3-B, at 27:7-32:23; Pl. Ex. 48, at "Data Entry" Sheet, row 147, col. B & E (formula bar: 0.25*30 + 0.75*20); July 2009 ELT Progress Report (Pl. Ex. 110), at AM-02465690 ("30MW gain in summer (3 mos), 20MW gain balance of year from Reheater, Economizer and APH investment"), Pl. Ex. 347, at AM-02637758 (same), June 15, 2009 CPOC Email (Pl. Ex. 895), at AM-02632842 (same).

278. In the Fall of 2009, Ameren also completed updated Full Work Order Authorizations for the replacement of the reheater, economizer, and air preheater. Consistent with previous projections, Ameren engineers described that a "gain of 30 MW in the summer and 20 MW in the winter will be obtained with the combined reheater, economizer, and air preheater replacements." October 15, 2009 Memo (Pl. Ex. 23), at AM-00926323; September 18, 2009 Memo (Pl. Ex. 26), at AM-00954160. Similar statements were made in other Ameren documents. *See, e.g.*, Pl. Ex. 893, at AM-02229417 ("Approximately 30 megawatts of unit capacity will be recovered during the hottest months because of lower gas flow pressure drops through the new economizer and air preheaters.").

279. Based on his review of Ameren's documents and data, Mr. Koppe confirmed that Ameren should have expected, and did expect, an increase in Unit 2's capability of at least 22 MW (gross) as a result of replacing the economizer, reheater, and air preheater. That additional capability would result from eliminating the effects of pluggage and allow Unit 2 to burn more coal per hour. Koppe Test., Vol. 3-B, 33:14-34:1; *see also* Vol. 3-A, 27:18-25, 29:2-8, Vol. 4-A, 46:23-47:18.

280. Ameren should not have expected any sustainable change in gross efficiency as a result of the reheater, economizer, and air preheater replacements. There was no expected efficiency benefits used as an input in the original Unit 2 project justification. The updated project justification included a 0.5% reduction in auxiliary load for the economizer and air preheater replacements, which equates to about 3 MW of net capability. The 3 MW reduction in auxiliary load would improve net efficiency, not gross efficiency, and would not be expected to change the full load heat input of Unit 2. FOF 117. Ameren did not project any decrease in fuel usage as a result of any efficiency changes associated with the component replacements. Koppe Test., Vol. 3-A, 5:13-20, Vol. 3-B, 28:13-29:8, Ex. 110, at AM-02465690 Pl. Ex. 48, at "Data Entry" sheet, at rows 149-152 (no decrease in fuel usage input for auxiliary load reductions).

281. Ameren's best expectation for the effect of the LP turbine on unit efficiency is that it would increase Unit 2's capability by 12 MW, which is the amount that was guaranteed by the vendor. Sind Test., Vol. 9-B, 20:3-12, 26:23-28:3. Ameren's updated financial analysis for the Unit 2 outage estimated that the efficiency improvements associated with the LP turbine would allow Unit 2 to produce 15 more MW of capability. The analysis was based on the assumption that the turbine-related efficiency improvements would allow Unit 2 to produce more megawatts but would not result in the unit burning less coal. Pl. Ex. 48, at "Data Entry" sheet, rows 149-152 (no "decrease in fuel usage" input for turbine replacement) Pl. Ex. 110, at AM-02465690; Koppe Test., Vol. 3-B, at 29:9-32:9.

2. Actual increases in Unit 2's capability

282. Consistent with the results achieved after the Unit 1 project, there was a big improvement in Unit 2 in the air preheater differential as a result of the air preheater replacements, where the differential pressure went from about 15 inches of water to about 5

inches. Koppe Test., Tr. Vol. 3-A, 25:22-27:17; Sind Test., Tr. Vol. 9-B, 25:6-26:2 (Mr. Sind's capacity analysis showed a big decrease in air preheater differential pressure from 13-14 inches to less than 6 inches); Williamson Test., Tr. Vol. 9-B, 44:7-14 (differential pressure of 15 inches indicates "high pluggage").

283. The improvement in the air preheater differential pressure, along with improvements in the other limitations (economizer differential pressure and ID fan suction pressure), meant that Unit 2's capability and ability to burn coal was no longer limited by pluggage after the Unit 2 boiler upgrade. Koppe Test., Tr. Vol. 3-A, 27:18-25, 28:7-14, 29:2-8. During the PSD baseline period, when the unit was experiencing extensive pluggage, the average full load capability of Rush Island Unit 2 was only 620 gross megawatts. FOF 120; Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; PX 928 (Rule 1006 summary of full load tests for Unit 2).

284. The increase in capability at Unit 2 was evident as soon as the unit returned to service after the 2010 outage. For example, on May 29, 2010, Ameren conducted a Full Load Test in which Unit 2's gross capability was measured to be 655 MW, exactly as Mr. Williamson had predicted in 2008. Compare May 29, 2010 Full Load Test (Pl. Ex. 236) (655.13 gross megawatts), with June 2008 Email (Pl. Ex. 267), at AM-02660307-08 (predicting 625 net megawatt); Williamson Test., Tr. Vol. 9-B 41:14-16 (confirming that 625 net megawatts equates to 655 gross megawatts); *see also* Sind Test., Tr. Vol. 9-B, 29:19-30:16. A full load test conducted in October 2010, after the unit had been in service for several months following the boiler upgrade, showed even higher capability. The gross capability measured during that test was 664 MW. October 19, 2020 Full Load Test (Pl. Ex. 913). No capability limitations were noted by plant engineers in either test report.

285. Similarly, in October 2010, Ameren performed a test to verify that the new reheater, economizer, and air preheater had satisfied their performance guarantees. Unit 2's capability during the performance test was recorded as about 659 MW (gross). Boiler Performance Test Report (Pl. Ex. 81), at AM-00482381.

286. Ever greater capability was noted among the "Bottom-Line Results" of the Unit 2 outage during the 2010 State of the System Meeting: "679 Gross MWs!" 2010 State of the System (Pl. Ex. 41), at AM-02493751.

287. After the 2010 outage, Ameren also reported a substantial increase in Unit 2's capability to its system operator, MISO, to NERC, and to the Missouri Public Service Commission. Specifically, in September 2010, Ameren reported to NERC that Unit 2's <u>summertime</u> peak capability had increased to 648 MW (gross), 617 MW (net), "due to work completed in the 2010 major boiler outage (replacement low pressure turbines and ***numerous boiler modifications***)." October 27, 2010 MISO Verification Test Data (Pl. Ex. 139), at AM-02663830 (emphasis added). Ameren provided the same information to NERC in September 2010. September 15, 2010 Capability Validation (Pl. Ex. 133), at AM-02645178; *see also* Koppe Test., Tr. Vol. 3-B, 46:6-47:22.

288. Later in December 2010, Ameren responded to a request from the Missouri Public Service Commission to identify any plant upgrades that it expected to result in an increase in the amount of electricity the plant would produce in the future. MPSC Data Request 0257 (Pl. Ex. 222); Koppe Test., Vol. 3-B, 50:22-51:11.

289. Ameren told the Missouri Public Service Commission that the 2010 outage, including the component replacements at issue, would result in a 34 MW increase in Unit 2's capability, which it characterized as having been based on a "significant capacity restoration[]"

of 22 MW and a "true capacity increase[]" of 12 MW. Ameren Resp. to DR 0257 (Pl. Ex. 223); Koppe Test., Vol. 3-B, 51:12-52:22. Joe Sind, the Ameren engineer who performed the analysis supporting Ameren's statements to the Missouri Public Service Commission, confirmed that the reported 12 MW "true capacity increase" was based on the company's best expectation of the impact of the LP turbine replacement on the capability of the unit. Sind Test., Tr. Vol. 9-B, 20:3-12, 27:12-28:3. Mr. Sind's work papers show that his capacity analysis only looked at changes in unit capability and air preheater differential pressures and that he reported increases in capability for other Ameren units where work had been done on air preheaters but no turbine work had occurred. Sind Test., Tr. Vol. 9-B, 22:3-23:17, 25:6-26:2.

290. Mr. Koppe confirmed the increase in capability reported by Ameren to the Public Service Commission was consistent with his review of "thousands of hours of operation at full power." Koppe Test, Tr. Vol. 4-A, at 49:16-23.

291. In its response to the Missouri Public Service Commission, Ameren also reported that a 2.4% efficiency improvement had occurred as a result of the 2010 overhaul, of which 1.9% was due to the LP turbine replacement and 0.5% was due to the reduction in auxiliary load caused by the air preheater and economizer replacements. Dec. 6, 2010 Email re: "Updated DR 0257 Spreadsheet" (Pl. Ex. 216), AM-02757946; Ameren Resp. to DR 0257 (Pl. Ex. 223), at AM-02762954; Sind Test., Tr. Vol. 9-B 26:23-28:3; Finnel Test., Tr. Vol. 10-A, 12:16-13:18. As a result, the increase in capability Ameren reported to the Missouri Public Service Commission was greater than the reported efficiency improvement, which means that Unit 2 would be capable of burning more coal as a result of the 2010 work. Sind Test., Vol. 9-B, 28:6-18; Koppe Test., Vol. 3-B, 52:3-22.

292. Ameren takes its obligation to provide truthful information to the Missouri Public Service Commission seriously. Meiners Rule 30(b)(6) Dep., Oct. 15, 2014, Tr. 19:5-13.

293. Outside of this litigation, Ameren has attributed only 12 MW of the megawatt capacity increase at Unit 2 to the replacement of the LP turbine. Even as recently as a January 2011 email, Mr. Shelton reconfirmed that the 1.9% improvement in efficiency that Ameren reported to the Missouri Public Service Commission equated to 12 MW. Mr. Shelton further stated that while there might be a little more increase, he could not quantify or estimate any such benefit because it would be too uncertain. Shelton Test., Tr. Vol. 10-A, 100:13-101:1, 102:11-103:20; January 21, 2011 Email (Pl. Ex. 935), at AM-02248224.

294. Ameren further raised the capability of Unit 2 after the 2010 boiler upgrade. In December 2010, the gross capacity of Rush Island Unit 2 was further increased to "better reflect the increase in output following the spring 2010 outage in which two new LP turbines were installed and several boiler components were replaced." The July 2011 gross capacity was listed as 641 MW, which was 26 MW greater than the July 2008 capacity, while the December 2011 gross capacity was listed as 653 MW. December 14, 2010 Capability Table (Pl. Ex. 257), at AM-00067232, 67235; Shelton Test., Tr. Vol. 10-A, 92:22-93:15.

295. Mr. Koppe also conducted an analysis of the company's operating data and found a very substantial increase in Unit 2's capability after the 2010 boiler upgrade. Koppe Test., Tr. Vol. 3-B, 5:25-6:3; *id*. at 19:14-19 ("comparing the baseline period to the post-project period, the capability of Unit 2 increased by a large amount"). Mr. Koppe's findings are consistent with Ameren's documents.

296. Mr. Koppe's analysis of the Plant Information ("PI") data focused on those hours in which Unit 2 was operated at "full load," as indicated by the fact that the turbine valves were

wide open, and accepting as much steam as the boiler could produce. Mr. Koppe's approach is consistent with the approach Ameren uses for its full load tests, which are weekly tests done by plant engineers to determine the capability of the units. Koppe Test., Tr. Vol. 3-B, 6:9-7:16, 8:20-9:8; Sind Test., Vol. 9-B, 30:1-7 (during a full load test, the plant is trying to generate as much output as it can).

297. The pre-project period in Mr. Koppe's analysis of the PI data was January 2006 through December 2007, which is the period of time closest to the PSD baseline for which Ameren produced a complete set of data. The capability of Unit 2 during that time was 615 MW. Koppe Test., Tr. Vol. 3-B, 34:2-35:13.

298. The post-project period in Mr. Koppe's analysis of the PI data was October 2010 to August 2011, because that period provided the "best measure … of how much the unit's actual capability had increased" as a result of the project. The post-project capability of Unit 2 was 653 MW (gross). Koppe Test., Tr. Vol. 3-B, 34:16-35:8.

299. Based on the Plant Information data, the overall increase in capability was 38 MW. This is a 6.2% increase in Unit 2's capability. Koppe Test., Vol. 3-B, 49:9-15.

300. Based on his analysis of the PI data, Mr. Koppe determined that 23.3 MW (3.8%) of the increase were related to the component replacements at issue, and 14.7 MW (2.4%) were related to efficiency improvements. The 23.3 MW related to the project at issue resulted in Unit 2 being able to burn more coal per hour. Koppe Test., Vol. 3-B, 34:2-35:13, 49:1-50:18.

301. A similar increase in capability is shown by looking at all of Ameren's full load tests conducted during the PSD baseline period and comparing them to the post-project period. Based on the full load tests, the average capability of Rush Island Unit 2 increased from 620 MW (gross) during the baseline period to 657 MW (gross) during the post-project period, for an

overall increase of 37 MW. Koppe Test., Tr. Vol. 3-B, 35:17-36:4, 45:12-46:5; see also Pl. Ex. 928 (1006 summary of full load tests for Unit 2).

3. Dr. Sahu's emission calculations based on Unit 2's capacity increase

302. As noted above, Dr. Sahu determined that a capability increase of only 1.7 MW at Rush Island Unit 2 will cause a 40 ton per year increase in SO_2 emissions. Sahu Test., Vol. 5, 41:11-14, 46:5-11.

303. Dr. Sahu calculated the emissions associated with an 18-MW increase in capability and determined that Ameren should have expected such an increase to result in an emissions increase of 416.8 tons per year of SO_2. Sahu Test., Vol. 5, 84:5-87:25.

304. The company's project justification documents indicate that it expected Unit 2's capability to increase as a result of the project by more than ten times the amount that would result in 40 additional tons of SO_2 per year. Because the actual and expected increase in capability far exceeded 1.7 MW, and exceeded the 18 MW used in Dr. Sahu's calculations, at least 40 tons of the overall increase in SO_2 emissions are related to the capability increase caused by the replacement of the economizer, reheater, and air preheater at Unit 2. Sahu Test., Tr. Vol. 5, 87:22-25, 97:3-98:16.

4. Nothing in Mr. Caudill's opinions negates Mr. Koppe's calculations of capability increases

305. In contrast with Mr. Koppe, Ameren's capability expert, Mr. Caudill, ignored Ameren's full load tests. He failed to even analyze the performance test that specifically assessed the post-project performance of the boiler upgrades. Although Mr. Caudill reviewed many Ameren performance test reports for turbines, including turbines at plants that are not at issue in this case, he did not review the performance test report for the new reheater, economizer,

and air preheaters that are actually at issue in this case. Caudill Test., Tr. Vol. 10-B, 53:7-54:6; Boiler Performance Test Report (Pl. Ex. 81).

306. Instead, Mr. Caudill simply applied "filters" to the pre- and post-project data that excluded more than 99% of the data in the periods he chose. For instance, the pre-project period he chose included 7,473 hours of data, but he filtered out all but 28 of those hours. Similarly, the post-project period he chose included 14,304 hours, but he filtered out all but 111 hours. Caudill Test., Tr. Vol. 10-B, 67:11-22. The effect of Mr. Caudill's decision to filter out 99% of the operating data was that he only included hours in his capability analysis when the unit was not load limited. Caudill Test., Tr. Vol. 11-A, 4:16-6:4. Rather than assess the actual capability of the Unit 2 boiler, Mr. Caudill excluded all of the effects of pluggage on the boiler's actual capability, including the thousands of hours of data that demonstrated the actual effects of pluggage when the boiler could not produce enough. Koppe Test., Vol. 3-B, 7:17-8:19.

307. Removing Mr. Caudill's filters drastically changes the results of his pre-and post-project comparisons. For instance, at Unit 2, the unfiltered data show that average hourly gross heat input actually increased by over 300 mmBTU per hour and that the maximum hourly gross heat input similarly increased by more than 300 mmBTU per hour. Caudill Test., Tr. Vol. 11-A, 7:10-8:2. Similarly, Mr. Caudill's unfiltered data show that average hourly MW increased by approximately 50 MW and that the maximum hourly megawatts increased by 29 MW. Caudill Test., Tr. Vol. 11-A, 8:3-15 (Caudill Cross Test.).

308. In addition to confirming that Unit 2 was actually operating at higher average hourly heat inputs after the 2010 outage, Mr. Caudill's unfiltered data also confirm that Unit 2 spent significantly more time operating at higher loads following the 2010 outage. For instance, during the pre-project period when Unit 2 was experiencing load limitations due to pluggage, it

spent only 10% of its operating hours at the highest load range identified by Mr. Caudill, with the largest fraction of the operating hours (40%) spent at the second highest load range. By contrast, after the 2010 outage the load range at which Unit 2 operated the most had shifted up to the highest load range identified by Mr. Caudill, with Unit 2 spending 40% of its operating hours at the highest load range after the 2010 outage as compared to 10% before the outage. Caudill Test., Tr. Vol. 11-A, 11:8-13:16. This is exactly what would be expected when a plugged boiler is no longer load limited following an upgrade.

309. Mr. Caudill also expressed an opinion on efficiency. However, his efficiency analysis suffered from at least two fundamental flaws that render it of little to no relevance here. First, Mr. Caudill conceded that his opinions do not address whether the projects were expected to, or did, cause increases in the total annual amount of generation or fuel burned at Rush Island. By analogy, Mr. Caudill explained that his analysis looked at the equivalent of miles-per-gallon rather than looking at the total gallons of fuel used in a year. Caudill Test., Tr. Vol 10-B, 11:20-12:12.

310. Second, Mr. Caudill did not analyze the required NSR pre-and post-project periods. Ameren itself has chosen specific two-year pre-project baseline periods to present in this case for purposes of determining whether its projects violated New Source Review. Vol. 10-B, 30:19-31:12 (Caudill Cross Test.). Yet Mr. Caudill only used approximately one year of pre-project data. And at Unit 2 there was not a single month in the pre-project period that Mr. Caudill used that actually overlapped with the two-year NSR baseline period that is at issue in this case. Caudill Test., Tr. Vol. 10-B, 32:4-33:17.

311. In addition, the time periods Mr. Caudill examined skew his results. For instance, he relied on pre-project periods when efficiency was significantly worse than it was during the

applicable NSR baseline period, effectively making the unit less efficient for purposes of his comparison. Ameren's Exhibit TW demonstrates that during the pre-project period selected by Mr. Caudill, Rush Island Unit 2 had the worst efficiency (i.e., the highest heat rate) in any of the five years leading up to the 2010 outage. Yet Mr. Caudill did not even look at data from those other years. Exhibit TW; Caudill Test., Tr. Vol. 10-B, 42:25-43:19.

D. PROSYM-BASED EMISSIONS CALCULATIONS

312. In addition to Dr. Sahu's translation of the performance improvements calculated by Mr. Koppe into calculations of emissions increases, the United States also presented emissions analyses performed by Dr. Ezra Hausman using Ameren's production cost modeling program.

313. Ameren's experts agree that using results from a production cost modeling run is an appropriate way to forecast future emissions for a New Source Review analysis. King Test., Tr. Vol. 6-B, 66:3-15; Chupka Test., Tr. Vol. 8-B, 80:14-17. In fact, Ameren expert Michael King admitted that he used production cost modeling runs in his New Source Review analyses in prior enforcement cases. King Test., Tr. Vol. 6-B, 66:16-19.

1. Production cost modeling at Ameren

314. "A production cost model is a computer application used to simulate an electric utility's generation system and load obligations." Finnell MPSC Test. (Pl. Ex. 439), at 3:10–11.

315. Ameren regularly uses a production cost model called ProSym to forecast its unit operations for a variety of business purposes, including fuel budgeting and rate case justifications before the Missouri Public Service Commission. Finnell MPSC Test. (Pl. Ex. 439), at 3:11–14; Ringelstetter Test., Vol. 11-B, 12:15–17.

316. Ameren's ProSym model is calibrated with actual load information to check its accuracy as a forecasting tool. Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 28:6-20. The calibration shows that the projection runs "come within a fairly high degree of accuracy." Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 28:6-29:13. According to Ameren, ProSym "does a good job of modeling the electric system and how it's operated." Finnell Rule 30(b)(6) Dep., Nov. 22, 2013, Tr. 29:2-13.

317. This computer simulation software uses a complex algorithm, but is basically a "supply and demand" model that predicts how the system operator, MISO, will dispatch Ameren's units hour-by-hour for a given period after taking into account various inputs like unit performance projections and load forecasts that Ameren develops as inputs into the program. Finnell Test., Tr. Vol. 9-B, 67:10–11; Hausman Test., Tr. Vol. 4-B, 41:17–23, 44:7–15.

318. As Ameren's witness Mr. Finnell explained, at Ameren, "[t]he fuel budget process involves collecting information from various work groups or [expert] areas in the company for items that are used in the ProSym model. The ProSym model is then executed, and the results are prepared and issued to various groups within the company." Finnell Test., Tr. Vol. 9-B, 66:22–67:1.

319. The fuel budgeting process typically involves forecasting unit operations for five years. Finnell Test., Tr. Vol. 9-B, 70:20- 21.

320. Ameren's modeling runs show how unit performance improvements interact with rising system loads or other market factors to affect unit operations. Hausman Test., Tr. Vol. 4-B, 40:7–12; Ringelstetter Test., Tr. Vol. 11-B, 56:10-21.

321. Jaime Haro, Ameren's manager in charge of load forecasting and risk management, testified at trial he had worked with the company's modeling department, and

confirmed that Ameren's modeling resources could be used to perform sensitivity analyses and investigate how different scenarios might impact operations at Ameren's units. Haro Test., Tr. Vol. 9-A, 133:1–14.

322. The inputs used by ProSym in simulating dispatch and operations can be divided into two types: market factors and unit characteristics. Hausman Test., Tr. Vol. 4-B, 42:13–17.

323. Market considerations that are input into ProSym include things like hourly load data—e.g., load forecasts for the market Ameren serves—as well as fuel costs, off-system market data, and system requirements. Finnell MPSC Test. (Pl. Ex. 439), at 3:3–5; Hausman Test., Tr. Vol. 4-B, 42:21–43:15.

324. Unit characteristics that are supplied for the model include measures of the unit's efficiency (also called its "heat rate" as it describes how much heat or fuel it takes for the unit to produce each unit of electricity), the unit's maximum capacity, the unit's projected availability, and other physical constraints such as how long it takes the unit to ramp up to full load if it is taken offline for any reason (its "ramping constraints"). Hausman Test., Tr. Vol. 4-B, 43:21–44:3.

325. As used by Ameren, the model takes into account two measures of unit availability when it projects unit operations: a unit's "forced outage rate," and its "partial outage rate." Hausman Test., Tr. Vol. 4-B, 52:25–53:20.

326. The forced outage rate is a measure of time that the unit was able to run at any level. So, in a non-leap year, it would be the number of hours the unit could run divided by 8,760, the number of hours in a year. Hausman Test., Tr. Vol. 4-B, 53:2–6.

327. The partial outage rate is the model's input for deratings. It is the percentage of actual available generation divided by the total available generation from the unit assuming

every available hour could have been loaded at full power. Hausman Test., Tr. Vol. 4-B, 53:9–15.

328. Adding the forced and partial outage rates of a unit together gives you the "effective unit outage rate." To determine a unit's equivalent availability factor, one subtracts the effective unit outage rate from 1. Hausman Test., Tr. Vol. 4-B, 53:16–54:9.

2. Dr. Hausman's sensitivity analyses

329. After investigating Ameren's modeling files, Dr. Hausman identified several performance improvements that Ameren modeled at its Rush Island plants concurrent with the boiler upgrade work at issue in this case. Hausman Test., Tr. Vol. 4-B, 47:19–48:2.

330. Dr. Hausman executed "sensitivity analyses" using Ameren's production cost modeling files to determine how the performance improvements at the Rush Island Units were impacting the modeling projections for those units' operations. Hausman Test., Tr. Vol. 4-B, 47:19–48:2.

331. A sensitivity test is a standard modeling technique whereby a modeler runs a computer simulation multiple times, varying only one input or parameter a little bit each time in order to investigate how that single element interacts with the rest of the system being modeled. Hausman Test., Tr. Vol. 4-B 46:24–47:8.

332. Dr. Hausman's sensitivity analyses revealed straightforward, linear relationships between unit capacity or unit availability and the unit's projected fuel use—and, accordingly, pollution levels. Hausman Test., Tr. Vol. 4-B, 55:20-56:19, 63:20-64:20, 65:22-66:7, 71:7-25, 72:12-21.

333. As shown below, any one of the performance improvements that Ameren modeled at the Rush Island units following the boiler upgrades would result in a concomitant

increase in fuel use that would translate into a pollution increase well above the 40 tons-per-year threshold for SO_2 to trigger New Source Review. Hausman Test., Tr. Vol. 4-B, 73:11–21.

a. Unit 1 sensitivity analysis

334. For Unit 1, Dr. Hausman reviewed a credible fuel budgeting modeling run performed in 2006 in order to evaluate how performance improvements following the 2007 projects at Unit 1 would be projected to affect operations and pollution. The model run he used was contemporaneously performed by the company when Ameren was planning the Unit 1 work, the modeling files were complete (allowing for replication and verification of the results), and the inputs presented credible, long-term forecasts without "red flags" such as artificial constraints or other indications that would suggest the model run was used for a different purpose or did not reasonably reflect company expectations. Hausman Test., Tr. Vol. 4-B, 68:4-16 & 97:15–98:1; *see also* Finnell Test., Tr. Vol. 10-A, 5:23–8:23 (discussing Plaintiff's Exhibit 892 and updates to Ameren's 2006 fuel budget modeling).

335. Comparing the year before the work was performed to the year after it was completed, Ameren modeled a 4% increase in equivalent availability following the boiler upgrades—a 2.2% improvement in the unit's forced outage rate and a 1.8% improvement in the unit's partial outage rate. Hausman Test., Tr. Vol. 4-B, 69:16–22.

336. Dr. Hausman determined that a one percentage point improvement in Unit 1's forced outage rate would translate into an additional 481 billion BTUs of fuel consumption per year and an additional 162 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 71:19-23.

337. Dr. Hausman also found that reducing Unit 1's partial outage rate (deratings) by one percentage point would result in an additional 408 billion BTUs of fuel consumption per year and an additional 138 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 72:12–21.

b. Unit 2 sensitivity analysis

338. For Unit 2, Dr. Hausman reviewed Ameren's "Original" 2010 Fuel Budget modeling run performed in early 2010 in order to evaluate how performance improvements following the 2010 projects at Unit 2 would be projected to affect operations and pollution following that work. That model run was used by Ameren's environmental services department to perform its "reasonable possibility analysis" for that work. Hausman Test., Tr. Vol. 4B, 49:6–10; Hutcheson Test., Vol. 11-A, 38:22-39:1.

339. Dr. Hausman determined that each additional megawatt of increased unit capacity at Unit 2 will result in that unit burning an additional 69 billion BTUs per year and an additional 23 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 59:24–60:2.

340. Dr. Hausman also found that a one percentage point improvement in the unit's forced outage rate would translate into an additional 566 billion BTUs per year and, as a result, an additional 189 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 64:15–20.

341. A one percentage point improvement in Unit 2's partial outage rate would translate into an additional 466 billion BTUs per year and, as a result, an additional 156 tons of SO_2 per year. Hausman Test., Tr. Vol. 4-B, 64:15–20.

3. Dr. Hausman's "with and without" analyses

342. In addition to his sensitivity analyses, Dr. Hausman also performed a "with and without" analysis using Ameren's ProSym model. A "with and without" analysis is a standard modeling technique used throughout the industry and in many fields that employ computer modeling. It compares two scenarios—one in which the performance improvements Ameren expected were realized (the scenario Ameren itself modeled), and another scenario in which the

units simply continued operating as they had in the past, without realizing any performance improvements as a result of the modifications. Hausman Test., Tr. Vol. 4-B, 25:12–18, 74:5–7.

343. This technique allows the modeler to look at the impact of one change (or set of changes) in the system while holding all else constant. Hausman Test., Tr. Vol. 4-B, 25:16–19 & 74:7–12.

344. Ameren's experts conceded that utilities often run a production cost model twice, changing just one variable, in order to see how changing that variable would impact the output of the model. King Test., Tr. Vol. 6-B, 67:14-19; Chupka Test., Vol. 8-B, 79:18-81:2. As Ameren expert Marc Chupka testified, the type of with-and-without modeling analysis that Dr. Hausman did in this case is a "standard tool" in utility modeling practice. Chupka Test., Tr. Vol. 8-B, 80:18-22.

345. Ameren expert Michael King agreed that the difference between two estimates of future emissions – one of which accounted for the project and one of which did not – would show the impact of the project. King Test. Tr. Vol. 6-B 69:7-71:23.

346. In his testimony in a prior NSR enforcement case, Ameren expert Michael King performed two modeling runs to identify the emissions that he testified were unrelated to the project and should be excluded from an NSR calculation under the demand growth exclusion. King Test. Tr. Vol. 6-B 65:17-21. In other words, Mr. King used the same technique in that case that Dr. Hausman did here (except Mr. King set out to identify the emissions that were *unrelated* to the project, while Dr. Hausman identified the emissions *related* to the project).

347. Similarly, Ameren expert Marc Chupka testified that one way to perform an NSR emissions analysis would be to (1) start with a contemporaneous emissions projection that

incorporates the effect of the project; (2) compare that projection to the baseline period; and then (3) address any unrelated factors. Chupka Test., Tr. Vol. 8-B, 81:3-24.

a. Unit 1 analysis

348. For Unit 1, Dr. Hausman's with-and-without analysis compared the ProSym modeling forecasts performed by Ameren in 2006 to another version in which the unit did not increase its availability by 4% following the work.

349. The comparison revealed that, but for the performance improvements modeled at the unit, Rush Island Unit 1 would have operated 192 fewer hours, the unit would have burned over 1,600 billion BTUs less coal, and it would have emitted 562 fewer tons in the year he examined. Hausman Test., Tr. Vol. 4-B, 79:23–80:7.

350. Based on Ameren's updated 2006 fuel budget modeling, the company projected that it would emit as much as 15,561 tons per year of SO_2 in the five years after the project, a 687-ton increase above baseline levels. Of that projected increase in emissions, 562 tons would not have been projected were it not for the availability improvements modeled at Unit 1. Hausman Test., Tr. Vol. 4-B, 80:10–21.

351. Dr. Hausman also used Ameren's Plant Information data to develop inputs based on the putative performance improvements in the company's Plant Information data. Dr. Hausman accepted the data at face value and gave Ameren credit for a 3.0% efficiency improvement (more than Ameren reasonably should have or did expect) and also incorporated a 20-MW increase in Unit 1's capacity. Hausman Test., Tr. Vol. 4-B, 81:1–3.

352. Using these inputs from the company's Plant Information data and re-running his with-and-without analysis, Dr. Hausman found that Ameren would have projected a 716-ton

increase above baseline pollution levels, of which 591 tons would not have been projected but for the performance improvements at the unit. Hausman Test., Tr. Vol. 4-B, 81:3–6.

b. Unit 2 analysis

353. For Unit 2, Dr. Hausman compared the ProSym modeling forecasts performed by Ameren to another version in which the unit did not increase its capacity by 18 MW and improve its availability by 2% following the work. The performance improvements represented by Ameren in this model are consistent with the performance improvements that Mr. Koppe independently determined the company should have expected to result from the boiler work. Hausman Test., Tr. Vol. 4-B, 82:21–24. The comparison revealed that, without the performance improvements modeled at the unit, Rush Island Unit 2 would have operated 96 fewer hours, the unit would have burned nearly 1,600 billion BTUs less in coal, and it would have emitted 746 fewer tons of SO_2 in the year he examined. Hausman Test., Tr. Vol. 4-B, 75:18–76:5.

354. Based on Ameren's "original" 2010 fuel budget modeling, the company projected as much as 16,816 tons per year of SO_2 in the five years after the project, a 2,528-ton increase above baseline levels. Of that projected increase in emissions, 746 tons would not have been projected were it not for the performance enhancements modeled at Unit 2. Hausman Test., Tr. Vol. 4-B, 76:22–77:6.

355. As with Unit 1, Dr. Hausman reviewed Ameren's Plant Information data to develop inputs based on the putative performance improvements contained in the company's data. Once again, Dr. Hausman accepted the Plant Information data at face value. Thus, Dr. Hausman gave Ameren credit for an efficiency improvement (4.2%) that exceeded what it reasonably should have or did expect, and also incorporated a 34 MW increase in capacity (a 5.75% increase). Hausman Test., Vol. 4-B, 79:6–8.

356. Using these PI-inputs and re-running his with-and-without analysis, Dr. Hausman concluded that Ameren still would have projected a 1,905-ton per year increase above baseline pollution levels, of which 696 tons would not have been projected but for the performance improvements at the unit. Hausman Test., Tr. Vol. 4-B, 78:21–79:2.

IV. AMEREN HAS FAILED TO MEET ITS BURDEN TO ESTABLISH THE APPLICABILITY OF THE DEMAND GROWTH EXCLUSION

357. Ameren pled as its Twenty-Sixth Affirmative Defense that any emissions increases following the 2007 and 2010 outages at Rush Island Unit 1 or Unit 2 were the result of increased demand and not the projects at issue. Answer (ECF No. 250), at 31.

A. Background about the Market for Rush Island's Generation

358. The Midcontinent Independent System Operator ("MISO") serves as the dispatch operator for Ameren's Rush Island units. Hausman Test., Tr. Vol. 4-B, 33:24–34:1.

359. As a dispatch operator, MISO aims to meet system demand with the lowest-cost—though still reliable—portfolio of electricity generation it can. "[G]eneration owners tell the dispatch operator what's available and at what price. And then the dispatch operator uses a computer algorithm to find the lowest cost way of meeting load." Hausman Test., Tr. Vol. 4-B, 33:19–23, 34:2–9.

360. "MISO's job is to find the lowest cost way of meeting that demand. And the way they do that is they start by turning on the lowest cost sources of energy first. Those are often nuclear or coal units like the Rush Island units. And then they progressively turn on more and more costly generators to run until at every moment the energy being generated is balanced with the load required by the system." Hausman Test., Tr. Vol. 4-B, 31:14–21.

361. As a general matter, electricity cannot be stored, so—at least when considering the system as a whole—electricity production and demand must be constantly balanced. Hamal Test., Tr. Vol. 9-A, 98:11–13. That does not mean, though, that electricity production and demand are the same thing. As with every market, the electricity market has a demand side and a supply side—and just because demand for electricity may be rising does not mean that any specific generating unit will be used to serve that rising demand. Hamal Test., Tr. Vol. 9-A 41:24–42:8.

362. The Rush Island units cannot generate—and so cannot serve demand—if they are unavailable. And Ameren cannot offer generation it does not have to the market: if a Rush Island unit was forced offline because of some mechanical failure, Ameren would not be able to offer Rush Island generation into the MISO market. Similarly, when Rush Island units are load limited or derated for some reason, Ameren cannot offer the unavailable portion of its generating capacity to the MISO market. Hamal Test., Tr. Vol. 9-A, 40:21–41:7; Naslund Test., Tr. Vol. 6-B, 13:24-14:5; King Test., Tr. Vol. 6-B, 52:24-53:6 (demand and availability are both necessary in order for a unit to operate).

363. Furthermore, in general, MISO cannot call on Ameren's units to provide more electricity than Ameren has offered into the market. Hamal Test., Tr. Vol. 9-A, 41:10–14; Hausman Test., Tr. Vol. 4-B, 35:6–9.

364. Ameren does not need MISO's permission to bring a unit offline if it has experienced a tube leak or other failure at the unit. Hamal Test., Tr. Vol. 9-A, 41:17–20; Hausman Test., Tr. Vol. 4-B, 35:10–12.

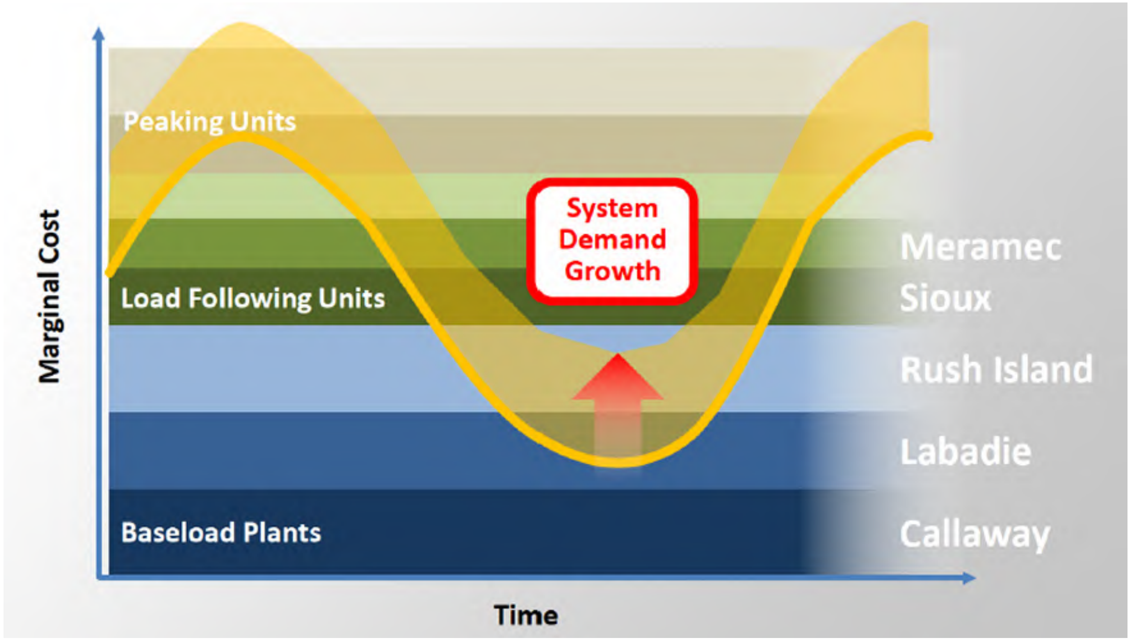
365. MISO does not tell generation owners like Ameren how to spend their capital improvement budgets or how to improve their generation services. Hamal Test., Tr. Vol. 9-A,

41:21–23; Hausman, Tr. Vol. 4-B, 35:13–19; Meiners Test., Tr. Vol. 7-B, 57:17-58:13. Ameren controls the engineering of its units and decides what maintenance work needs to be performed and when to perform that work. Hausman Test., Tr. Vol. 4-B, 36:3–6; Meiners Test., Tr. Vol. 7-B, 57:17-58:13. By controlling the maintenance of and investment in the Rush Island generating units, Ameren manages those supply assets to ensure that they can serve as much market demand as they can. Hausman Test., Vol. 4-B, 35:23–36:21.

366. MISO does not pay bonuses to generation owners when their units perform well or reliably. Hausman Test., Tr. Vol. 4-B, 35:20–22.

367. "Rush Island has low operating cost[s]. MISO's job is to run the system as efficiently as possible, and that translates into MISO doing what it can to get Rush Island to run more." Hamal Test., Tr. Vol. 9-A, 37:20–23. As a natural corollary, if Ameren is able to make the Rush Island units able to operate more hours or at higher loads, then MISO would call on them to make use of that new-found capability. Hamal Test., Tr. Vol. 9-A, 51:22–52:17.

368. Jaime Haro, Senior Director of the Ameren's Enterprise and Commodity Risk Management Department, described how the Rush Island units compare to other units in Ameren's generating portfolio by providing a generalized schematic of the "merit order" or "dispatch order" of its various plants. Haro Test., Tr. Vol. 9-A, 130:14 – 132:9; Hausman Test., Tr. Vol. 4-B, 31:14–32:22. At the bottom of the schematic are units that cannot shut down and are the cheapest to run, such as Ameren's Callaway nuclear plant. Next up to be dispatched are other baseload coal units such as the Rush Island generating units that run basically whenever they are available. Haro Test, Vol. 9-A, 65:1–66:1; Tr. Vol. 6-A, 55:4-7.



[Ameren Demonstrative WC_2]

369. Coal units like Rush Island are expensive to shut down, and it takes hours—sometimes as much as a day—to start them back up. Hamal Test., Tr. Vol. 9-A, 45:10–15. As such, the Rush Island units may ramp down their generation through the night or during other periods of low system load, but they generally do not turn off. Hamal Test., Tr. Vol. 9-A, 46:7–23; Haro Test., Tr. Vol. 9-A, 131:7–12.

370. As illustrated by Ameren's schematic, the general impact of an increase in system demand is that the Rush Island units might ramp down a little later at night than they otherwise would, or ramp up to high loads a little earlier in the mornings than they otherwise would. Haro Test., Tr. Vol. 132:2–9.

371. As Mr. Haro testified, though, when load is up, as it often is during the "on peak" hours shown with relatively high prices at the left and right hand side of the graphic, the Rush Island units are typically generating as much as they can. Haro Test., Tr. Vol. 9-A, 131:1–15.

Obviously, if the unit is already fully loaded, it cannot increase its output in order to serve more of the market's demand for electricity. Hamal Test., Vol. 9-A, 58:16–17.

372. In general, the Rush Island units are more likely to be running fully-loaded during "on peak" hours than "off peak" hours. Hamal Test., Tr. Vol. 9-A, 59:3–5, 59:17–19. Even according to Ameren's expert's analysis, only a third of the hours the Rush Island Unit 2 operated with some available capacity to spare were "on peak" hours. Thus, according to Ameren's expert, Unit 2 was at maximum capacity for more than half of all hours in the baseline period—and more than two-thirds of all "on peak" hours in the baseline period. Ringelstetter Test., Vol. 11-B, 40:10 – 15; Def. Demonstrative TK-15.[3]

373. This relationship is borne out in Ameren's modeling files. For example, as is evident in Ameren's modeling efforts performed in 2006, even when the company forecast system load to increase each year, the Rush Island units were projected to generate at essentially flat levels throughout the forecast period. As Dr. Hausman explained, this clearly indicates the Rush Island Units are baseload units, and they are more or less insensitive to variations in system load. Hausman Test., Tr. Vol. 4-B, 45:20–22.

B. Ameren's Failure of Proof Regarding Demand Growth as a Cause of Increased Emissions

374. In the company's 2011 Corporate Social Responsibility Report, Ameren characterized the projects at issue in this case as "necessary to respond" to increased demand. Naslund Test., Tr. Vol. 6-B, 16:12-15, 18:3-5; Corporate Social Responsibility Report (Pl. Ex.

[3] Even this number appears to understate how often the units were run at their "available capacity." Ms. Ringelstetter's analysis does not accurately reflect those hours when the unit was ramping up after coming offline. She counted those hours as having "available capacity" even though the units would have been physically incapable of generating more during that time. Ringelstetter Test., Vol. 11-B, 69:3–70:15.

431) at AM-00510618. In other words, Rush Island could not have served at least some of the increasing system demand *without* the Rush Island upgrade projects.

375. To the extent that system demand was growing, as of 2008, Ameren expected that its purchase of three combustion turbines (natural gas units), would satisfy that demand growth until at least 2018. Naslund Test., Tr. Vol. 6-B, 15:14-16:11.

376. To the extent that system demand was growing, Ameren did not offer any evidence at trial to show how changes in system demand, if any, would or did specifically impact the operation of and emissions from the Rush Island units. For example, Ameren utility market expert Cliff Hamal admitted that he did not quantify "how demand would change Rush Island's operations in any way." Hamal Test., Tr. Vol. 9-A, 39:23–40:5.

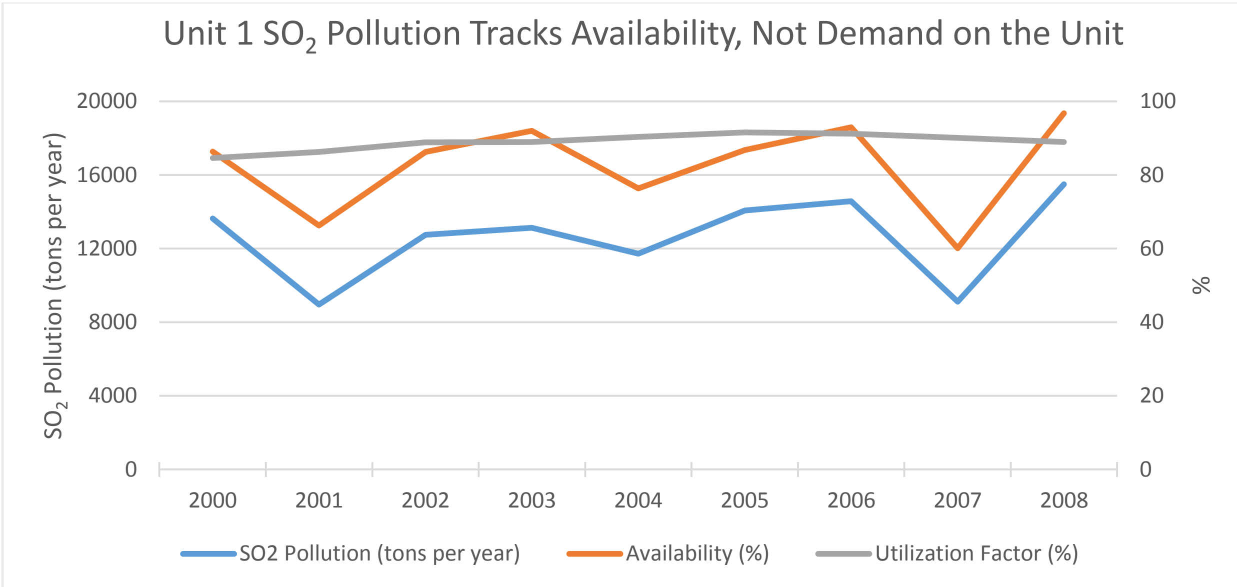
377. The industry does have a standard measure that isolates demand for the output of individual generating units. That metric is known as the "utilization factor," and Ameren itself uses it during the course of its business. Sahu Test., Tr. Vol. 5, 56:18-57:3, 76:15-22; Ringelstetter Test., Tr. Vol. 11-B, 80:18-81:6; Economic Evaluation of Plant-upgrading Investments (Pl. Ex. 241), at AME_RHK000011-12 ("loading order [is] reflected in the utilization factor") (EPRI Report, Vol. 1); Availability Worksheet (Pl. Ex. 250), at Spreadsheet Tab "Instructions" (utilization factor is the "percent of mwhrs used after outages and derates").

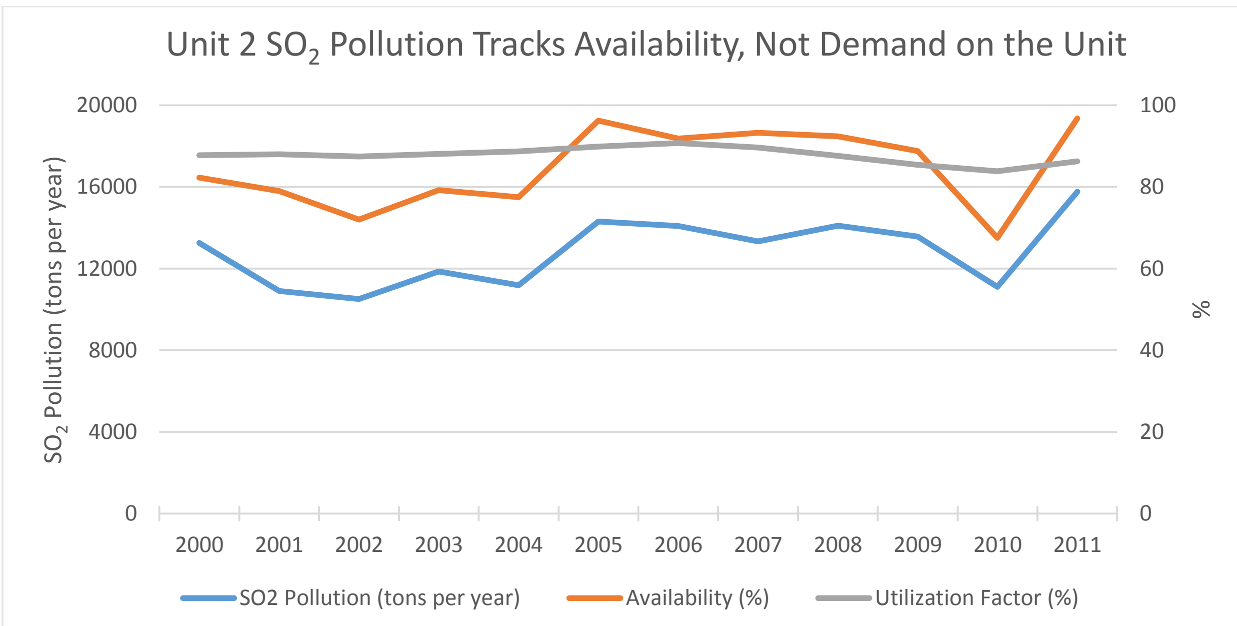
378. Ameren expert Michael King testified that demand for the generation of coal units had been decreasing since 2007 due to falling natural gas prices. King Test., Tr. Vol. 6-B, 34:20-35:3, 35:8-16. Mr. King also testified that the utilization factors for the Rush Island units have been declining since around 2007. King Test., Tr. Vol. 6-B, 87:13-24. Mr. King further explained that if the utilization factor is decreasing, any emissions increases during that time period cannot be the result of increased demand. King Test., Tr. Vol. 6-B, 88:3-6, 89:9-12.

379. Ameren expert Sandra Ringelstetter calculated utilization factors in this case and found that the utilization factor for Unit 1 was projected to remain basically constant and in fact decreased from 91.18% in the baseline period to 89.66% in the applicable post-project period. Ringelstetter Test., Tr. Vol. 11-B, 83:4–15; Def. Ex. NE, at "RI U1 2007 Summary" tab. As a result, any increase in generation that was projected to occur and was in fact realized at Unit 1 following the 2007 outage cannot be attributed to increased demand.

380. For Unit 2, Ms. Ringelstetter calculated that Unit 2's utilization was projected to increase slightly (about 2%), but that it in fact decreased from 91.45 in the baseline period to 89.37 in the relevant post-project period. Ringelstetter Test., Tr. Vol. 11-B 81:7-83:3; Def. Ex. NE, at "RI U2 2010 Summary" tab. As a result, the more than 15% increase in emissions that was projected to occur and that was in fact realized at Unit 2 following the 2010 boiler upgrades cannot be attributed to increased demand.

381. At Rush Island, emissions of SO_2 track availability of the units more closely than demand. Sahu Test., Tr. Vol. 5, 103:5-107:19; *see also* King Test., Tr. Vol. 6-B, 86:2-23 (Ameren expert conceding the relationship between availability and SO_2 pollution at Rush Island).





382. Ameren did not offer any evidence to explain how an increase in emissions associated with an increase in capacity at Rush Island can be caused by demand growth.

V. AMEREN'S NSR EMISSION ANALYSES

383. Ameren called two witnesses at trial from its Environmental Services Department: Steven Whitworth and Michael Hutcheson. Mr. Whitworth was the Supervisor of the Air

Quality section within Ameren's Environmental Services Department from 2002 to 2007. In 2007, Mr. Whitworth became Department manager, which meant that he has ultimate responsibility over the entire Environmental Services group. Whitworth Test., Tr. Vol. 11-A, 90:4-9. Mr. Hutcheson works for Mr. Whitworth and was the Ameren employee responsible for performing the NSR emissions calculations that Ameren presented at trial. Hutcheson Test., Tr. Vol. 11-A, 34:2-35:2, 54:20-55:11, 63:9-15.

384. Ameren does not have any internal guidelines for performing a New Source Review analysis. Hutcheson Test, Tr. Vol. 11-A, 65:21-24.

385. The Environmental Services Department at Ameren is responsible for determining New Source Review applicability. Environmental Services does not have any role in Ameren's capital project justification process. Naslund Test., Tr. Vol. 6-B, 19:20-23, 20:7-18.

386. Project justification packages include a document called the Project Risk Management Plan. Schweppe Dep., May 20, 2014, Tr. 112:2-7.

387. Robert Schweppe was Director and later Managing Supervisor of the Project Engineering group at Ameren. Prefatory Statement to Depo Designation, Vol. 6-A, 19:9-11; Project Approval Package (Pl. Ex. 1), at AM-0072586. Mr. Schweppe signed off on the Project Risk Management Plan for the major component replacements at issue for both Unit 1 and Unit 2. Project Approval Package (Pl. Ex. 1), at AM-00072606 (Unit 1 boiler components); Project Approval Package (Pl. Ex. 3), at AM-00072841 (Unit 2 boiler components); Project Approval Package (Pl. Ex. 4), at AM-00072864 (Unit 1 air preheater); Project Approval Package (Pl. Ex. 6), at AM-00072923 (Unit 2 air preheater).

388. Each Project Risk Management Plan lists whether certain risk factors have been addressed, followed by a series of check boxes. One of the check boxes is for

"Legal/Environmental." For each of the projects at issue, the Legal/Environmental box was not checked. Pl. Ex. 1 at AM-00072606; Pl. Ex. 3 at AM-00072841; Pl. Ex. 4 at AM-00072864; Pl. Ex. 6 at AM-00072923.

389. Mr. Schweppe testified that he did not know why the Legal/Environmental box was not checked, and that he did not "recall that box ever being checked" for "any project risk plan." Mr. Schweppe continued that he did not know what the box meant and that he had never asked anyone to understand what it meant. Schweppe Dep., May 20, 2014 Tr., 112:14-114:5.

A. Ameren Performed No Pre-Project NSR Analysis for Either Project

1. Rush Island Unit 1

390. Ameren has admitted that it performed no emission calculations for purposes of determining PSD applicability prior to undertaking the 2007 project at Unit 1. Whitworth Test., Tr. Vol. 11-A, 94:23-25; Boll Test., Tr. Vol. 8-B, 38:3-5; Birk Dep., Sept. 24, 2013, Tr. 220:14-21; *see also* Knodel Test., Tr. Vol. 1-A, 88:10-12; Ameren Closing Arg., Vol. 12, 51:18-20.

391. Mr. Whitworth, the Head of Ameren's Environmental Services department, testified at trial that the only pre-project emission evaluation he did for Unit 1 was a non-numerical analysis that considered only whether the Unit 1 project would increase the unit's potential to emit. Mr. Whitworth also admitted that he relied on an inapplicable provision of the Missouri regulations. Whitworth Test., Tr. Vol. 11-A, 88:16-25, 90:12-15, 90:20-92:19; *see also* Boll Test., Tr. Vol. 8-B, 9:7-13:25 (company relied on non-numerical evaluation of whether project would have an impact on maximum continuous rating), 38:3-14.

392. Ameren's Environmental Services Department did not communicate with project engineer David Boll at any time prior to the Unit 1 project completion in 2007. Boll Test., Vol. 8-B, 39:17-21, 40:6-9.

393. The Rush Island Plant Manager at the time of the 2007 outage was Robert Meiners. As plant manager, he was accountable for making sure the plant complied with environmental regulations. Meiners Test., Tr. Vol. 7-B, 64:2-5. However, Mr. Meiners had no communications with anyone about whether to seek a New Source Review permit for the Unit 1 project. When asked whether he understands that PSD requires utilit[ies] to make a prediction of future emissions in order to do [] emissions analys[es], Mr. Meiners replied "That's not – not my responsibility. I'm not involved with it." Meiners Dep., April 8, 2014, Tr. 342:11-17. In fact, Mr. Meiners testified that throughout his more than 40-year career at Ameren, he never had a single discussion with anyone about whether or not to seek an NSR permit for any capital project at all. Meiners Test., Tr. Vol. 7-A, 68:2-18 and Vol. 7-B, 64:2-20. Similarly, Mr. Strubberg testified that he was not involved in any assessment of whether the projects triggered PSD. Strubberg Test., Tr. Vol. 8-A, 73:17-74:5.

394. Prior to undertaking the Unit 1 project, Ameren did not communicate with permitting authorities about whether a New Source Review permit would be required. Whitworth Test., Tr. Vol. 11-A, 106:3-7.

2. Rush Island Unit 2

395. The Head of Ameren's Environmental Services department, Mr. Whitworth, testified at trial that the only pre-project emission evaluation he did for Unit 2 was a non-numerical analysis that considered only whether the Unit 2 project would increase the unit's potential to emit. Mr. Whitworth also admitted that he relied on an inapplicable provision of the Missouri regulations. Whitworth Test., Tr. Vol. 11-A, 88:16-25, 90:12-15, 90:20-92:19.

396. The Ameren employee who was responsible for doing NSR calculations for Unit 2 was Michael Hutcheson. Mr. Hutcheson testified that he did not review any EPA or

Missouri Department of Natural Resources guidance specifically as part of his work for the project at issue. Hutcheson Test., Tr. Vol. 11-A, 65:25-66:2.

397. Mr. Hutcheson admitted he had no personal knowledge of the project or whether the effects of the project were included in the projections he relied upon.

a. Mr. Hutcheson testified that in performing the company's NSR analysis, he did not speak to any of the engineers who planned and developed the project. He received information from his superiors in the Environmental Services Department, but he did not know the source of that information. Hutcheson Test., Tr. Vol. 11-A, 63:5-19.

b. Mr. Hutcheson also testified that he did not review any of the project justification documents for the work. Hutcheson Test., Tr. Vol. 11-A 63:20-25.

c. Mr. Hutcheson did not know whether the modeling runs that he relied on for his analysis included any projected improvements in capacity or availability. Mr. Hutcheson did nothing to check the validity of the modeling runs he received, but simply "took them on their face." Hutcheson Test., Tr. Vol. 11-A, 65:4-20; Hutcheson Dep., April 24, 2014, Tr. 118:20-119:5.

d. Mr. Hutcheson testified that he did not consider whether availability was expected to improve as a result of the projects because he did not think that information was "relevant" or "necessary." Hutcheson Test., Tr. Vol. 11-A, 82:16-25.

398. Mr. Hutcheson performed two purported NSR analyses for the Rush Island Unit 2 project – the "Original" Reasonable Possibility Analysis and the "Amended" Reasonable Possibility Analysis. Neither analysis was completed before the project work started. Knodel Test., Tr. Vol. 1-A, 88:13-18; Whitworth Test., Tr. Vol. 11-A, 96:12-23, 97:2-15; Hutcheson

Test., Tr. Vol. 11-A, 84:15-17, 85:3-8. Mr. Hutcheson's analysis relied on a ProSym model run the company performed that had been completed in January 2010, after the outage had begun. Hutcheson Test., Vol. 11-A, 38:22-24. The Original Reasonable Possibility analysis was not completed until after the project had begun. Mr. Hutcheson admitted that the analysis *should* be completed before beginning construction. Hutcheson Test., Tr. Vol. 11-A, 56:1-7; 84:15-85:2; *see also* Knodel Test., Tr. Vol. 1-A, 88:24-89:3.

399. Mr. Hutcheson began working on the Original Reasonable Possibility Analysis only after Ameren's legal department requested analyses of about 20 projects, including the Rush Island Unit 2 project. Some of the projects he was asked to analyze had already occurred and some were planned for the future. Hutcheson Test., Tr. Vol. 11-A, 34:2-23.

400. Although the Unit 2 project was originally approved in 2005 and re-approved by Ameren's Board of Directors and CEO on August 14, 2009 (FOF 136, 137), Mr. Hutcheson did not even begin collecting information relevant to his NSR analysis until November or December 2009. Hutcheson Test., Tr. Vol. 11-A, 84:11-14.

401. Ameren's "Original" ProSym modeling run was not completed until January 2010, after the 2010 outage had begun. The original case was used to develop the corporate budget for 2010. Finnell Dep., Nov. 22, 2013, Tr. 79:2-8. After the 2010 outage was complete, Ameren ran two other modeling cases, including the "EDF" case. Finnell Test., Tr. Vol. 10-A, 9:25-10:5. The EDF case was completed in early 2011. Finnell Test., Tr. Vol. 10-A, 10:3-5. The EDF case was the same as the "Original" case, but was modified to include efficiency improvements. Finnell Dep., Nov. 22, 2013, Tr. 77:12-20. The EDF case was used by environmental services to perform the Amended Reasonable Possibility Analysis. Finnell Dep., Nov. 22, 2013, Tr. 76:4-79:8; Hausman Test., Tr. Vol. 4-B, 87:11-14.

402. Ameren's Original Reasonable Possibility analysis "projected" that Unit 2's emissions of SO_2 would increase by 2,531.15 tons per year, from 14,287.73 in the baseline period to 16,818.88 tons per year in the highest projected post-project period. Hutcheson Test., Tr. Vol. 11-A, 40:22-41:2; Knodel Test., Tr. Vol. 1-A, 91:10-17; Def. Ex. C at Tab Net Emissions Change; *see also* Pl. Ex. 493, at AM-02231873, at "projected Emissions" tab (showing even higher projected SO_2 emissions of 17,018 for Unit 2 in 2012).

403. Ameren excluded every ton of the projected emissions increase on the basis that Unit 2 was capable of accommodating all of the increases in the baseline. Ameren provided no other reason for excluding the projected emissions increases in its Original Reasonable Possibility Analysis. Knodel Test., Tr. Vol. 1-A, 91:10-17. Mr. Hutcheson stated that there was no mechanism in his spreadsheet (Def. Ex. C and D) to account for whether the projected increase was related to the project. He testified that the relatedness question was a "qualitative" one not a "quantitative" one. Hutcheson Test., Tr. Vol. 11-A, 80:22-81:3.

404. Ameren did not rely on any guidance or applicability determinations in making their capable of accommodating determination. Whitworth Test., Tr. Vol. 11-A, 102:3-8, 103:24-104:3.

405. In late 2010, well after Ameren had completed the Unit 2 boiler upgrade, Mr. Hutcheson was asked by Ameren's in-house counsel, Susan Knowles, to revise his analysis. Hutcheson Test., Tr. Vol. 11-A, 85:3-11; Naslund Test., Tr. Vol. 6-B, 18:14-19; Hutcheson Dep., April 24, 2014, Tr. 115:2-12. Mr. Hutcheson used the EDF case to perform the Amended Reasonable Possibility Analysis. Hutcheson Dep., April 24, 2014, Tr. 117:10-20; Hausman Test., Tr. Vol. 4-B, 87:11-14.

406. Mr. Hutcheson completed the Amended Reasonable Possibility Analysis in early 2011, almost a year after the Unit 2 project had begun, and then only after EPA had issued a Notice of Violation to Ameren and after this lawsuit had been filed. Knodel Test., Tr. Vol. 1-A, 92:14-24, 93:15-19; Hutcheson Test., Tr. Vol. 11-A, 55:2-56:9, Def. Ex. D; RFA No. 7.

407. Mr. Hutcheson was asked to perform the Amended Reasonable Possibility analysis in order to incorporate a 2.4% efficiency improvement expected from the 2010 outage. No efficiency improvement had been incorporated into the Original Analysis. Mr. Hutcheson was not asked to make any other changes to the inputs into the analysis, such as changes that reflected the full extent of the capacity or availability improvements at Unit 2. Hutcheson Dep., April 24, 2014, Tr. 115:13-23; 117:10-20.

408. Ameren's expert, Mr. King, testified that he would not perform an NSR analysis based on a modeling run that was created just for NSR purposes. Mr. King agreed that in using such a run, a source runs the risk of looking like it is "cooking the forecast" to project no emissions increase. King Test., Tr. Vol. 6-B, 67:20-68:13.

409. Even with the changes made to the efficiency input, Ameren's Amended Reasonable Possibility Analysis still "projected" an increase of SO_2 emissions of 2,059.30 tons per year. Knodel Test., Tr. Vol. 1-A, 93:3-5; Def. Ex. D. As with its original analysis, Ameren excluded every ton of the projected emissions increase on the basis that the unit was capable of accommodating those emissions in the baseline period. Ameren provided no other basis for excluding those emissions increases. Knodel Test., Tr. Vol. 1-A, 93:6-14.

B. Ameren's Post Hoc Reasonable Possibility Analysis is Substantively Flawed

1. Ameren's calculations fail to model all of the performance improvements expected from the boiler upgrades

410. Ameren's Reasonable Possibility Analysis was based on its computer simulations performed for fuel budgeting purposes in January 2010. Those simulations include an 18 MW increase in Unit 2 capacity and a 2% improvement in unit availability—resulting in a 95% EAF—for the unit following the boiler work at issue in this case. *See* FOF 338, 353.

411. But project justification documents developed in 2009 projected significantly better performance at Unit 2 following the work. The CPOC report relied on a 22.5 MW increase in unit capacity as a result of the boiler work, as well as a 4.2% improvement in availability—resulting in a nearly 97% EAF—for the unit following the upgrades. *See* FOF 157, 158, 253.

2. Ameren's capable of accommodating approach

412. Ameren calculated the emissions the unit was capable of accommodating before the project by using the amount of time the unit was available to operate and multiplying that by the 95th percentile emissions rate (in pounds per hour). Hutcheson Test., Tr. Vol. 11-A, 41:3-17, 47:20-48:6, 68:16-24. Mr. Hutcheson calculated the 95th percentile emissions rate in Def. Ex. C, Tab Sheet1 and the results are shown in columns X and Y of the tab. Hutcheson Test., Vol. 11-A, 46:18-47:1.

413. Mr. Hutcheson's use of the 95 percentile emissions rate was not based on anything in the New Source Review rules. Hutcheson Test., Tr. Vol. 11-A, 69:13-70:5. Nor was it a standardized practice within Ameren. In fact, he used a 97th percentile emissions rate for nitrogen oxides for the same project. Hutcheson Test., Tr. Vol. 11-A, 78:3-22; Def. Ex. C at Tab RI U2 W2010 Detail.

414. In selecting the emissions rate for the capable of accommodating analysis, Mr. Hutcheson wanted to pick a rate that was "representative of what the unit could accommodate in

the baseline." The value he picked was in the top five percent of emissions rates that the unit achieved during the baseline period and that the median value would have been the 50th percentile. He also testified that he "would have no doubt" that there could be a big difference between the 95th percentile value and the 50th percentile value. Hutcheson Test., Tr. Vol. 11-A, 70:12-71:11.

415. Mr. Hutcheson did not look to see whether Unit 2 actually ran at the 95th percentile value for even 24 hours. Hutcheson Test., Tr. Vol. 11-A, 73:8-11.

416. The 95th percentile calculation that Mr. Hutcheson said was a representative emissions rate for Unit 2 actually included several hours in which Unit 2 was emitting at a rate well over what is allowed by its permit. Def. Ex. C at Tab Sheet1 (Column L, Rows 4563-4574 and 4590-4591); Hutcheson Test., Tr. Vol. 11-A, 73:12-21.

417. By using the 95th percentile emissions rate, Ameren calculated it would have accommodated about 17,550 tons of SO_2. Hutcheson Test., Tr. Vol. 11-A, 67:5-16. That much annual pollution would be more than Unit 2 had emitted since 1995, when the units were required to make reductions under the Acid Rain program. Declaration of Steven Whitworth (Pl. Ex. 926), at p. 10; Hutcheson Test., Tr. Vol. 11-A, 67:20-68:6; Knodel Test., Tr. Vol. 1-A, 56:1-4.

418. Mr. Hutcheson testified that had he used an average SO_2 emissions rate rather than the 95th percentile rate, it would "essentially be recalculating the baseline." Hutcheson Test., Vol. 11-A, 47:12-14. This is incorrect. Ameren's capable-of-accommodating calculation is based on the unit's *availability*, not on the actual operation. It calculates the additional emissions impact from running every hour the unit was available.

419. Had Mr. Hutcheson used the 50th percentile value for the SO_2 rate, even Ameren's flawed analysis would show the project triggered New Source Review. This can be seen from Def. Ex. C. Column Y on Sheet1, which has the results of the 95th percentile calculation. The calculation is linked to the ultimate emissions calculation set forth in Tab Net Emissions Change. Hutcheson Test., Vol. 11-A, 76:8-24; Def. Ex. C.

420. When clicking on the interactive formula bar for Cell Y8 in Tab Sheet1, the user can change .95 to .5 and thus run the calculation using the 50th percentile. After doing so, the Net Emissions Change tab automatically changes: the capable-of-accommodating number becomes 197 tons, the net change (the emissions increase) becomes 2,334 tons, and the spreadsheet indicates that the project triggers New Source Review. Def. Ex. C at Tab Net Emissions Change (Columns E, G, and I).

Using 50th percentile SO2 rate (3,491 lb/hour)								
Unit	**Pollutant**	**Baseline Emissions (tons/year)**	**Projected Actual Emissions (tons/year)**	**Capable of Accomodating Emissions (tons/year)**	**Excluded Emissions (tons/year)**	**Net Change (tons/year)**	**Significance Level (tons/year)**	**Significant (Yes/No)**
Rush Island 2	NO_x	2,099.73	2,522.83	459.51	423.10	-	40	No
	SO_2	14,287.73	16,818.88	***196.88***	***196.88***	***2,334.27***	40	***Yes***
	PM_{10}	56.24	67.73	11.28	11.28	0.20	15	No

3. No analysis of relatedness

421. Mr. Hutcheson testified that to assess whether the increase was related to the project he talked to several people including his boss, Ken Anderson, and Steven Whitworth, the

head of the Environmental Services Department. None of the engineers who planned the outage were involved. Hutcheson Test., Tr. Vol. 11-A, 81:4-16.

422. Mr. Hutcheson testified that they discussed the heat rate, maximum design rate of the boiler, and SO_2 emissions rate. They concluded that those characteristics would not change due to the projects and thus any increase was not related to the projects. Hutcheson Test., Vol. 11-A, 49:17-50:21.

423. In performing the New Source Review analysis for Unit 2, Mr. Hutcheson did not look at whether availability was expected to increase as a result of the project. He testified that if the unit was capable of accommodating additional demand, "the availability is not necessarily relevant" and that it "wasn't necessary" to look at availability for his analysis. Hutcheson Test., Vol. 11-A, 82:16-25.

424. In contrast to Mr. Hutcheon's trial testimony, Ameren in fact uses availability predictions as part of its process to determine how much coal to buy. The company does so because the more available a unit like Rush Island is, the more it will generate and the more coal it will need. Naslund Test., Tr. Vol. 6-B, 11:6-16.

425. Ameren also used availability in the *baseline* as the basis for its capable of accommodating calculations. As Mr. Hutcheson explained, the company looked to availability to determine what the unit was capable of generating before the project. Hutcheson Test., Tr. Vol. 11-A, 44:9-14, 87:4-12.

426. In Rule 30(b)(6) testimony, Steven Whitworth, the head of Ameren's Environmental Services Department, testified as Ameren's corporate representative. Mr. Whitworth testified that he believed emissions that a unit was capable of accommodating are per se unrelated. In the Rule 30(b)(6) deposition, Whitworth testified that, "The emissions that the

unit was capable of accommodating prior to the outage would be totally unrelated to . . . any activities that occurred on the outage. So just by the nature of the scope, the emissions are unrelated." Whitworth Rule 30(b)(6) Dep., Dec. 4, 2013, Tr. 38:4-12; Whitworth Test., Tr. Vol. 11-A, 101:19 – 102:2.

C. Nothing in Ms. Ringelstetter's Analyses Excuses Ameren's Failure to Perform Appropriate NSR Projections

1. Ms. Ringelstetter failed to address relatedness for either unit

427. Changes in availability would affect how much the unit was projected to generate. Ringelstetter Test., Tr. Vol. 11-B, 78:3–9.

428. Changes in unit capacity would affect how much the unit was projected to generate. Finnell Test., Tr. Vol. 10-A, 9:7–10.

429. Ms. Ringelstetter examined selected ProSym modeling files and observed that Ameren projected changes in the Rush Island units' availability and capacity following the boiler work at issue in this case, but testified that those changes had nothing to do with the boiler work. *See, e.g.*, Ringelstetter Test., Vol. 11-B, 56:10–15.

430. Ms. Ringelstetter noted that the maximum capacity at Rush Island Unit 2 was projected to be 11 MW above baseline levels following the boiler upgrades, but she attributes the capacity increase entirely to the LP turbine work performed in 2010. Ringelstetter, Vol. 11-B, 17:20–24 & Ameren's Summary Exhibit XF_2 (indicating 11 megawatt increase).

431. However, her baseline capacity number is not a measure of the unit's actual performance based on operating data; rather it is a reported number that tracks Ameren's Capability Tables. Ringelstetter Test., Tr. Vol. 11-B, 73:12–74:9.

432. Ameren's documents and witnesses stated that the company's 2005 Capability Tables were "unrealistically high" and were later adjusted downward significantly in February, 2006. Finnell Test., Tr. Vol. 10-A, 5:23–8:23 (discussing Plaintiff's Exhibit 892 and updates to Ameren's 2006 fuel budget modeling which show adjustments from the "unrealistically high" 610 MW to values between 581-596 MW). Since Ameren's selected baselines for both units include substantial amounts of 2005, Ms. Ringelstetter's 11 MW number significantly understates the projected capacity increase at Unit 2 compared to Ameren's documents and data. FOF 157, 289, 299, 300, 301.

433. Ms. Ringelstetter further testified that Ameren's ProSym models projected an increase in availability at each unit following the boiler upgrades, but stated that the increase is not substantial enough to appear to be a meaningful difference, and so discounts it entirely for her emissions assessment. Ringelstetter Test., TR. Vol. 11-B, 17:4–12.

434. Ms. Ringelstetter discounted these increases even though the availability forecast for Ameren's economic justification of the work at Unit 2 was fine-tuned to the tenth of a percent, and even that tiny variation meant hundreds of thousands of dollars dropped out of the analysis. June 15, 2009 Email (Pl. Ex. 895), Meiners Test., Tr. Vol. 7-B, 34:9-35:25.

435. Ms. Ringelstetter offered no opinion on how—if at all—the projects at issue in this case would have been expected to change the operations of the Rush Island units. Ringelstetter Test., Tr. Vol. 11-B, 59:23–60:3.

436. Nor did Ms. Ringelstetter offer any independent opinion on whether or to what extent the low pressure turbine replacement that occurred at Rush Island Unit 2 alongside the boiler modifications had any impact on unit operations or performance. Ringelstetter Test., Tr. Vol. 11-B, 60:4–9.

437. As such, all of her emissions analyses—and all of the emissions she concludes should be excluded from the emissions projection—rest on the assumption that *none* of the projected emissions increases were caused or enabled by the projects at issue in this case. Ringelstetter, Tr. Vol. 11-B, 18:9–11 & 22:2–9.

438. When she developed her calculations for her expert report, Ms. Ringelstetter believed it was *irrelevant* whether the projects at issue in this case resulted in performance improvements. Rather, by her calculations, the only thing that mattered for the demand growth exclusion was whether the unit "could have accommodated" the projected emissions levels during the baseline. Ringelstetter Test., Tr. Vol. 11-B, 77:2–17.

2. Ms. Ringelstetter's Unit 1 analysis relies on faulty assumptions

a. Background regarding ancillary services

439. Ancillary services are things other than simple electric generation that utilities provide to keep the electric grid operating reliably. Generally they involve promises that certain amounts of generation will be held in reserve or would be dedicated to real-time adjustments in response to market fluctuations. When a unit was providing some ancillary services, it would typically not be operating at its full capabilities. Hamal Test., Tr. Vol. 9-A, 23:4–6; Haro Test., Tr. Vol. 9-A, 99:21–100:13.

440. On January 1, 2007, Ameren Missouri entered into a short term contract to provide ancillary services to its Illinois affiliates. Def. Ex. HX. That contract was to last "from January 1, 2007 until the earlier of (i) December 31, 2007, or (ii) the date during calendar year 2007 on which the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") ancillary services market for Ancillary Services is operational." Def. Ex. HX at 1.

441. The short-term contract was later renewed when the launch of MISO's ancillary service market was further delayed. Haro Test., Tr. Vol. 9-A, 133:24–134:7.

442. The contract did not specify how much of the ancillary services described in the contract would be provided by Rush Island units or how often the units would be assigned to provide those services. Def. Ex. HX at Article 3, § 3.1.1 and Schedule A.

443. As of January 2009, ancillary services such as regulation hours and spinning reserves were offered into—and cleared through—MISO's ancillary services market. Hamal Test., Tr. Vol. 9-A, 43:10–12; Ringelstetter Test., Tr. Vol. 11-B, 95:10–14.

444. As Mr. Hamal explained: "In order to provide [ancillary services], you can't be at full load. You have to back off. You have to be at partial load. And so when prices are really high, I'd rather have a high-cost unit at partial load than a low-cost unit." Hamal Test., Vol. 9-A, 24:11–15.

445. The Rush Island units would not be expected to provide ancillary services once MISO's ancillary service market was implemented. Ameren's contract for ancillary services was never intended to extend beyond when MISO's ancillary services market started up in 2009. Haro Test., Vol. 9-A, 102:1-14, 134:4-7.

446. The MISO ancillary services market helped optimize the provision of ancillary services like regulation and spinning reserves: "it allow[ed] MISO to look at the fact that not only is that unit providing regulations, but it's not providing energy. So if that's a low-cost unit providing regulation, there may be a high-cost unit that could provide that regulation and save the system money overall." Hamal Test., Tr. Vol. 9-A, 24:5–10.

447. Since the Rush Island units are relatively-low cost units that run all the time, (Hamal, Tr. Vol. 9-A, 26:16–17), the implementation of the MISO ancillary services market

meant they would be "held back" little if any to provide ancillary services once those services were cleared through the market system. Hamal Test., Tr. Vol. 9-A, 24:20–24.

448. Ameren's chief modeler, Mr. Timothy Finnell, explained that in order to model ancillary services like regulation hours or spinning reserves in ProSym, Ameren would inflate a unit's partial outage rate, thereby depressing the unit's availability in the model. That would, in effect, lower the output of the units that were assigned to regulation in the model. Finnell Test., Tr. Vol. 9-B, 99:3–7; *see also* Ringelstetter Test., Tr. Vol. 11-B, 62:4–63:17.

449. Mr. Finnell admitted that assigning units regulation hours or ancillary services in the model would affect how much generation they were expected to produce and how much coal they were expected to burn in the forecast years. Ameren modeled ancillary services by increasing a unit's partial forced outage rate. Increasing the forced outage rate results in reduced generation and coal burned in the model. Finnell Test., Tr. Vol. 9-B, 99:3–100:19.

450. In 2008, Mr. Finnell, then head of Operations Analysis in Ameren's Corporate Planning Department and in charge of the company's ProSym modeling, testified before the Missouri Public Service Commission about how the sale of ancillary services impacted the company's business forecasts:

> Q. Is AmerenUE selling ancillary services to the utility operating subsidiaries owned by Ameren Corporation in Illinois?
>
> A. Yes, for 2008, AmerenUE is selling 39 MW of spinning reserves and 68 MW of supplemental reserves to Illinois affiliates.
>
> Q. Does the PROSYM model include the sales of ancillary services to these Illinois utilities?
>
> A. No. The sales of these ancillary services were not included because they are based on a short-term contract that will end when the MISO ancillary service market begins.

Finnell MPSC Test. (Pl. Ex. 439), at 12:16–23.

451. Neither of Ameren's two experts hired to discuss dispatch and market issues quantified how the provision of ancillary services influenced Rush Island operations before the projects were performed or once the modifications were completed. Mr. Hamal "didn't get into the details and quantify how much regulation Rush Island did," focusing instead on the general market structure. Hamal Test., Tr. Vol. 9-A, 44:3-5. Ms. Ringelstetter, despite offering an opinion that Ameren's modeling of ancillary services was "entirely appropriate," (Ringelstetter Test., Tr. Vol. 11-B, 66:4–6), did not mention ancillary services, regulation hours, or spinning reserves in her expert report, nor was she aware of any "specifics" regarding Ameren's short-term ancillary service agreements. Ringelstetter Test., Tr. Vol. 11-B, 66:10–67:10.

b. Ms. Ringelstetter's modeling choice

452. For the analysis in which she concludes that projected emissions would not increase following the Unit 1 modification work, Ms. Ringelstetter uses a ProSym modeling effort that includes two artificial adjustments.

453. First, the ProSym modeling run that Ms. Ringelstetter used when assessing the 2007 project at Rush Island 1 included an input for that unit which was intended to reflect its provision of ancillary services. Despite the short-term nature of the services as described above, she used a run where Unit 1 was modeled as holding back 15 MW for regulation hours for *every year* of the model forecast, 2007 through 2012. Ringelstetter Test., Tr. Vol. 11-B, 63:18–64:2; *see* Hausman Test., Tr. Vol 4-B, 97:3-9.

454. Second, Ms. Ringelstetter claims the modeling effort suffered from what she calls a bias in the inputs which requires a downward adjustment to the model's projections. However,

Ameren never performed such an adjustment when it did its own analyses, and in fact other modeling efforts did not suffer from this bias. Hausman Test., Tr. Vol. 4-B, 98:9–99:12.

455. Without either of these adjustments, Ms. Ringelstetter's analysis would show a significant projected increase in Rush Island 1 operations and pollution above baseline levels. Hausman Test., Tr. Vol. 4-B, 99:13–23.

VI. THE 2007 AND 2010 BOILER UPGRADES TRIGGERED TITLE V REQUIREMENTS

456. The Clean Air Act Title V permit for the Rush Island Plant contains a condition restating the requirement that Ameren was prohibited from performing any unpermitted major modifications of Rush Island Units 1 or 2. Declaration of Steven Whitworth (Pl. Ex. 926), at attached Title V Permit, AM-02511339-2511393, at 2511362.

457. Ameren has not obtained a permit for its major modifications, and the Rush Island Title V permit does not incorporate PSD requirements for its major modifications. Pl. Ex. 926, at attached Title V Permit, AM-02511339-2511393, at 2511348-350 (Listing no Unit Specific Emission Limitations for SO_2).

CONCLUSIONS OF LAW

I. OVERVIEW

Under the Clean Air Act's PSD program, an existing source of pollution must obtain a permit and install state-of-the-art emissions controls when the source makes a "major modification." *Ameren SJ Decision*, 2016 WL 728234, at *4. The United States claims Ameren violated the PSD program's requirements by making major modifications to Units 1 and 2 at Rush Island without obtaining applicable permits or installing required emissions controls. The only disputed element of proof is whether the projects performed on Units 1 and 2 were "major modifications" under the law. *See* Subsection II.A (other elements of proof undisputed). To prove a major modification, the United States must show the work at issue was (1) "a physical change or change in method of operation that (2) would result in a significant net emissions increase." *Ameren SJ Decision*, 2016 WL 728234, at *2 (citing 40 C.F.R. §52.21(b)(2)).

For the purposes of the first prong of the test, the term "physical change" is extremely broad, and there is no dispute that the projects were physical changes. *Id.* at *4. But not all physical changes trigger PSD permitting requirements. Routine maintenance, repair, and replacement projects are excluded from the definition of "major modification." *Id.* Ameren argues the challenged Rush Island projects were routine maintenance projects and as a result exempt from being considered "physical changes." Subsection III.A below explains why the challenged projects are not routine maintenance.

For the purposes of analyzing the second prong of the test, Subsection II.B below explains that the projects would be expected to result in—and did result in—a significant net emissions increase. Because the projects were physical changes that would result and did result in a significant net emissions increase, they were major modifications under PSD.

Because the United States has proved the Rush Island projects were major modifications, Ameren violated the PSD provisions of the Clean Air Act because it did not obtain the required permits or meet other PSD requirements before beginning construction. In addition, as explained in Subsection II.C below, Ameren also violated the Title V provisions of the Clean Air Act.

II. THE UNITED STATES PROVED THAT AMEREN VIOLATED THE PREVENTION OF SIGNIFICANT DETERIORATION AND TITLE V PROVISIONS OF THE CLEAN AIR ACT

A. Undisputed Elements of Proof

The only disputed element of proof is whether the projects were major modifications under the law.

There is no dispute that:

- Ameren is a "person" under the applicable law and the owner and operator of the Rush Island facility. 42 U.S.C. 7602(e) and 10 C.S.R. 10-6.020(2); FOF 2.

- Rush Island Units 1 and 2 are each a "major emitting facility," a "major stationary source," and an "electric steam generating unit" under the applicable PSD and Title V provisions. 42 U.S.C. § 7479(1), 40 C.F.R. § 52.21(b)(1) and (b)(31); FOF 13.

- EPA provided sufficient pre-filing notice of the violations to Ameren and the State of Missouri and provided notice of the filing of this case to the State. 42 U.S.C. § 7413(a), (b); FOF 18-21.

- At the time of the projects, Rush Island was in an area designated as attainment for SO_2. 42 U.S.C. § 7471; FOF 11. Therefore the PSD program applies.

B. The Projects Should Have Been Expected to Cause—and Did Cause—Emissions Increases

1. **Legal standard**

There are two ways to establish PSD liability. The United States can satisfy its burden by proving either that: (1) the source should have expected an emissions increase related to the project (the expectations approach); or (2) an emissions increase related to the project actually occurred (the actual emissions approach). *Ameren SJ Decision*, 2016 WL 728234, at *16; *see also* 40 C.F.R. § 52.21(a)(2)(iv)(*b*), (*c*).

Regulations establish how to compare pre- and post-project emissions. The pre-project "baseline" is any 24 consecutive months in the 5 years before the project. 40 C.F.R. §52.21(b)(48)(i). The post-project period is the maximum annual emissions in any one of the five years after the project. 40 C.F.R. §52.21(b)(41)(i). The difference between the baseline and post-project high emissions year is the emissions increase for PSD purposes. An increase of 40 tons or more of SO_2 per year is "significant" under the regulations. 40 C.F.R. §52.21(b)(23)(i). In this case, there is no evidence of any creditable emissions decreases, so any emissions increase proven is the same as the net emissions increase. *See* 40 C.F.R. § 52.21(b)(3).

Under the expectations approach, courts must determine what a source should have expected at the time of the project. To prevail, the United States "must show that at the time of the projects [defendant] expected, or should have expected, that its modifications would result in a significant net emissions increase." *Ameren SJ Decision*, 2016 WL 728234, at *13 (citing cases and quoting *United States v. Ala. Power Co.*, 730 F.3d 1278, 1282 (11th Cir. 2013) (internal quotations omitted)).

Ameren's internal documents are relevant to what the company expected or should have expected. *See, e.g.*, *Ala. Power*, 730 F.3d. at 1286-87; *United States v. La. Generating LLC*, 929 F. Supp. 2d 591, 593-594 (M.D. La. 2012) ("The documents clearly show outages were a problem and the company planned to work on the reheaters in order to fix those problems."); *Ohio Edison*, 276 F. Supp. 2d at 834 ("The documents prepared to justify the expenditures described the various purposes of the projects to include replacement of major components to increase the life and the reliability of the units.").

Under the actual emissions approach, the question is simply whether SO_2 emissions actually increased by more than 40 tons per year as a result of the project.

Under either approach, additional operations made possible by a project must be attributed to that project. As EPA has explained, "where the proposed change will increase reliability, lower operating costs, or improve other operational characteristics of the unit, increases in utilization that are projected to follow can and should be attributable to the change." 61 Fed. Reg. 38,250, 38,268 (1996). A series of court decisions have echoed this requirement.

"If an increase in hours of operation is caused or enabled by a physical change, the increased hours must be included" in the projection. *Duke Energy 2010*, 2010 WL 3023517, at *5; *see also Duke Energy 2007*, 549 U.S. at 577-78 (noting regulatory provision that requires assessing number of hours the unit is or probably will be running); *Ala. Power*, 730 F.3d at 1281; *United States v. Cinergy Corp.*, 458 F.3d 705, 710 (7th Cir. 2006) (revitalizing a plant to operate more hours may trigger PSD obligations); *Ohio Edison*, 276 F. Supp. 2d at 834-35 (finding PSD liability for projects that were "intended to result in increased hours of operation as a result of a reduction in . . . forced outages").

Even when there is evidence that emissions will or did increase after a project, a source may demonstrate that the increased emissions should be excluded from PSD review under the "demand growth exclusion." Under the demand growth exclusion, a source must exclude from its calculations:

> any emissions increases that "an existing unit could have accommodated during the consecutive 24–month period used to establish the baseline actual emissions . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." 67 Fed.Reg. at 80,277 (codified at 40 C.F.R. § 52.21(b)(41)(ii)(c)).

New York v. U.S. E.P.A., 413 F.3d 3, 31 (D.C. Cir. 2005) ("*New York I*"). After substantial argument about the application of the demand growth exclusion at summary judgment, I explained its application as follows:

> if emissions increase because a project enables the unit to meet previously unmet demand during peak hours, for example, those emissions increases are likely related to the project and therefore do not qualify for the demand growth exemption. . . if the unit undergoes modifications that allow it to run more during the daytime hours tha[n] it could before, it cannot be said that the increased emissions were merely a coincidence or unrelated to the modification.

Ameren SJ Decision, 2016 WL 728234, at *10.

Finally, Congress intended for the PSD rules to "have broad application." *Id*. (citing *Ala. Power Co. v. Costle*, 636 F.2d 323, 399-400 (D.C. Cir. 1979)).

2. **The evidence shows that Ameren should have expected an emissions increase related to each project, and such an emissions increase occurred**

The core facts of this case show that before Ameren performed the challenged projects, problems with the components at issue were limiting the units' performance. Replacing those components would improve performance and result in additional use and pollution. That was what Ameren should have expected before the work began. The evidence shows that is what Ameren *did* expect. The evidence also shows that is exactly what happened.

Two key—and undisputed—characteristics of the Rush Island units underlie the entire discussion of emissions increases. First, the Rush Island units are big sources of pollution. That means even small performance improvements can enable a 40-ton increase in SO_2. For example, there is no dispute that it only takes an additional 21 hours of operations at full power for a Rush Island unit to emit more than 40 tons of SO_2. FOF 190.

Second, the Rush Island units are "baseload" units. FOF 6. They are relatively cheap sources of electricity. FOF 50. The market for electricity, which puts a premium on price, drives these baseload units to operate as much as they can. *Id*. That means the Rush Island units run every hour they are available—and at high or even maximum levels during hours of "peak" demand. FOF 6, 371-372. Moreover, Rush Island's baseload status means that if the units improve their performance in any way that allows them to generate more electricity, the market will call on the units to generate more electricity. FOF 50, 215. As Ameren's retired executive Charles Naslund explained at trial, Ameren plans its coal purchases based in part on availability projections because the company knows that the more available the Rush Island units are, the more they will run. FOF 424. That additional generation requires additional coal—and means additional pollution. FOF 205.

These two facts lead to a logical conclusion: if the Rush Island units are upgraded so they *can* generate more electricity, they *will*. Performance improvements have a direct impact on annual generation and pollution levels. Ameren's witnesses and documents recognize this simple relationship. FOF 424, 427-428, 448. And using Ameren's computer modeling software, United States' expert Ezra Hausman illustrated that a mere one-megawatt improvement in unit capacity would lead to an additional 23 tons per year of SO_2 pollution and that a one percent improvement in unit availability would result in about 150 extra tons of SO_2 per year. FOF 336-337, 339-41. Ameren should have expected the Rush Island boiler upgrades to result in at least an additional 40 tons of SO_2 pollution—and that is exactly what happened.

a. The Koppe-Sahu emissions calculations show a predicted increase at Unit 1 and were confirmed by an actual increase

Before the projects, the components at issue were causing outages and deratings at Unit 1. FOF 47-88. Ameren's availability data showed that the economizer, reheater, lower slope tubes, and air preheater were the predominant cause of availability losses at the unit, so Ameren decided to replace them with redesigned components. FOF 136, 138-139, 222-223. The decision to replace these components was the result of a lengthy and deliberate process and was ultimately approved by a series of managers and executives, culminating with the Ameren parent company CEO. FOF 136, 177. One of the bases of that approval was the expectation that the replaced components would cause *no* outage time for *20 years* following the projects. FOF 38, 145-149. Looking at the unit as a whole, Ameren expected that Unit 1's long-term availability would increase to 95% after the work was done, about a 3% increase compared to the PSD baseline. FOF 228.

The United States' expert Robert Koppe did his own analysis of how the project would affect Unit 1's performance. Mr. Koppe is a power plant engineer who has spent much of his career analyzing the performance of generating units on behalf of utilities and public service commissions using methodologies that courts have consistently found to be reliable. FOF 90-91; *see, e.g., United States v. Cinergy Corp.*, 623 F.3d 455, 459 (7th Cir. 2010); *United States v. Ohio Edison Co.*, 276 F. Supp. 2d 829, 877 (S.D. Ohio 2003). Mr. Koppe analyzed the problems affecting Rush Island during the baseline period and determined what Ameren should have expected to result from the work it did in the 2007 and 2010 outages. FOF 195.

Mr. Koppe started by identifying all the outage hours and deratings attributed to the components at issue during the baseline. He found that the equivalent availability losses due to the four components at issue totaled 336 hours in the baseline period, about half the unit's total outage time.[4] FOF 197, 222. Importantly, Mr. Koppe also looked at the condition of the unit as a whole and the other work performed during the 2007 outage. FOF 197-198. As Mr. Naslund explained at trial, Ameren was working hard to address any potential future problems during the outage. FOF 199. Mr. Koppe concluded that the other work performed during the 2007 outage would prevent availability from declining due to other potential issues. FOF 255. He also

[4] Ameren claims that Mr. Koppe and Dr. Sahu should have accounted for derates differently. This portion of Ameren's criticism has to do with what is known in the industry as a "utilization factor" and whether Mr. Koppe and Dr. Sahu should have used a different utilization factor for deratings than they did for outages, as Ameren's expert Marc Chupka testified he would have done. But Mr. Chupka is an economist, not a power plant engineer, and Dr. Sahu's use of a single utilization factor for both outages and deratings is exactly what the Electric Power Research Institute ("EPRI") has recommended since the 1980s. FOF 210. In fact, except for the purposes of this litigation, Ameren instructs its engineers to do the very same thing. FOF 210.

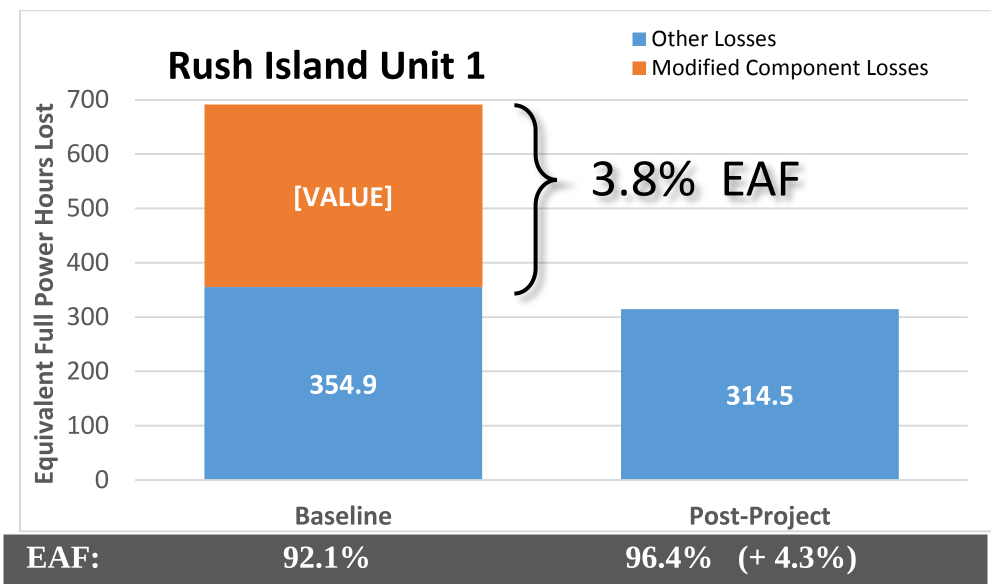
concluded that the project would completely eliminate availability losses from the components at issue and result in an availability improvement of 3.8% from the baseline, bringing Unit 1's availability to about 96% post-project.[5] FOF 224-225, 227. Mr. Koppe concluded—and Ameren witnesses and documents confirm—that availability would not have increased at all if these problematic components had not been replaced. Rather, it would have gotten worse. FOF 227, 231, 239, 255.

Dr. Ranajit Sahu, a permitting engineer and expert for the United States, took Mr. Koppe's findings on expected improved availability and used them to calculate the expected additional pollution that would result from the improvements, using a methodology that has been recognized as industry-standard by several courts. *See, e.g.*, *Ala. Power*, 730 F.3d at 1284-85; *La. Generating*, 929 F. Supp. 2d at 596. Dr. Sahu concluded, as Ameren did, that the company would utilize the regained hours at the same proportion as it had in the past. FOF 206, 208. Based on his and Mr. Koppe's analyses, Dr. Sahu calculated an expected increase in emissions of 608 tons of SO_2 post-project for Unit 1. FOF 232. Because Dr. Sahu's calculation was based on

[5] Ameren argues in its post-trial brief that Mr. Koppe testified that it would not be reasonable to expect the units could achieve over 95% availability post-project because "things happen" and "other components can fail." Ameren then argues that an increase to 95% at Unit 1 is no significant increase at all because Unit 1 had a baseline availability of 94.7%. There are two major flaws with this argument. First, Mr. Koppe did not testify that the units would not be expected to achieve over 95% availability; in fact, he testified that Ameren should have expected "the fairly long-term average equivalent availability" to reach about 95%, but "the best performance post-project" (which is the relevant measure) "would be more like 97 or 98 percent." Koppe Test., Tr. Vol. 3-A, 79:7-14. Second, Ameren's argument that there was no expected significant availability increase only works if its suggested baseline availability figure of 94.7% is accepted. That figure is at odds with Mr. Koppe's well-supported calculation that Unit 1's baseline availability was actually 92.1%. Ameren's calculations appear to be based on the exclusion of certain GADS events from its performance data, but Ameren offered no testimony at trial to support that approach.

the additional operation allowed by the project, the entire predicted increase is related to the work. *Id.*

Post-project results confirm Mr. Koppe and Dr. Sahu's calculations. In 2008, Unit 1 set its record availability with the best availability in the entire Ameren system. FOF 234; *see also* FOF 236. As Mr. Koppe and Ameren both expected, all the outages and deratings due to the replaced components were eliminated. FOF 237. Availability during the highest post-project emissions year reached 96.4%, which is 4.3% higher than the baseline. FOF 238. The entire expected improvement related to the project (3.8%) was realized. That improvement was an order of magnitude more than the 0.3% increase needed to result in 40 additional tons of SO_2. FOF 191. The chart below shows the baseline availability losses caused by the components at issue (orange) and caused by all other factors (blue). After the work was completed, Unit 1's actual availability climbed to 96.4% and it did not experience any losses due to the new components and actual availability. FOF 237–38.



With the availability improvement came an actual increase in emissions of 665 tons of SO_2. FOF 664. Those additional tons were made possible by the availability improvement and are related to the project. FOF 239.

At trial, Ameren sought to exclude any testimony from Mr. Koppe and Dr. Sahu on the cause of the actual increase. As discussed below (*see* Subsection I.A on Evidentiary Issues), I am denying Ameren's motions to strike this testimony because I find that the challenged opinions were properly disclosed. But even without the challenged testimony, the evidence shows an actual and significant net increase of emissions related to the project for both units. Ameren has *not* challenged the admissibility of the testimony by Mr. Koppe and Dr. Sahu that:

- An availability improvement of just 0.3% or an additional 21 hours of operation would cause a more than 40 ton-increase in pollution.

- The work would eliminate all availability losses due to the components, increase overall availability by far more than 0.3%, and increase pollution.[6]

- Post-project data shows those predictions came true: there were no component losses of any kind in the post-project year, availability improved by much more than 0.3%, the unit operated hundreds of hours more, and pollution increased.

FOF 267. Mr. Koppe and Dr. Sahu made a prediction based on improved unit performance, and the actual data confirmed those predictions. As Mr. Koppe explained at trial:

> [If] half of all the outage time that's occurring is eliminated by the projects and the effect of all the other equipment in the unit stays the same . . . then the availability of the unit as a whole increases, and it increases specifically because the projects have eliminated boiler tube leaks in these sections and have eliminated the effects of pluggage.
>
> ***
>
> The causation of what actually happened is obvious from the—from the data.

Koppe Test., Tr. Vol. 4-A, 115:18-25, 4-B, 18:1-4.

[6] Ameren concedes that Unit 1 availability was projected to increase by 1.3%. Ameren Br. at 5 (Doc. 835).

Here, based on the substantial and credible evidence presented showing how the project would cause improvements in availability and, as a result, increase emissions, I am able to find, even without explicit expert testimony, that the predicted cause of the increase was the cause of the actual emissions increases. *See, e.g.*, *United States v. Crenshaw*, 359 F.3d 977, 988 (8th Cir. 2004) (citing *Jackson v. Virginia*, 443 U.S. 307, 319 (1979) (noting court authority "to draw reasonable inferences from basic facts to ultimate facts").

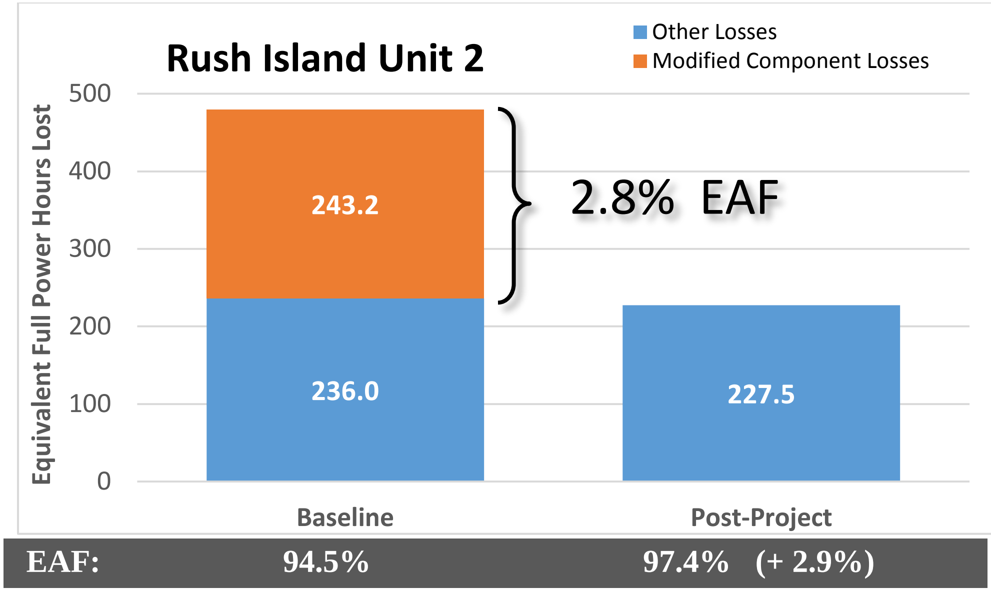
b. The Koppe-Sahu emissions calculations show a predicted increase at Unit 2 and were confirmed by an actual increase

The background story of Unit 2 is the same as Unit 1. Unit 2 had the same problems with the components at issue limiting the unit's availability in the time leading up to the outage. As with Unit 1, Mr. Koppe analyzed the expected impact of the 2010 project on Unit 2's availability. FOF 47–88, 145–47, 197–98. Mr. Koppe found that the outages and deratings at Unit 2 caused by the economizer, reheater, and air preheater resulted in about 245 equivalent lost hours during the baseline, slightly more than half the total lost operating time. FOF 247. As with Unit 1, Mr. Koppe examined the overall condition of Unit 2 and found that other work performed during the outage would prevent availability from getting worse and that the component replacements would result in an availability improvement. FOF 251. For Unit 2, he predicted that the project would completely eliminate all of the losses due to the three components at issue and, by itself, would improve Unit 2's availability by 2.8%. FOF 248, 251. None of these improvements would be possible if Ameren had not replaced the reheater, economizer, and air preheater. Rather, without the project, availability at Unit 2 would have decreased, not increased. FOF 255.

Ameren argued at trial that availability could *never* increase beyond 95%. But former plant manager Robert Meiners agreed with Mr. Koppe and Dr. Hausman that the long-term availability forecast of 95% meant individual years would be as high as 97% or 98%. FOF 257. As noted above, the relevant PSD inquiry compares the baseline emissions to the year with the highest amount of projected emissions in the five-year post-project period. Tellingly, Ameren already knew that Unit 1 set an availability record after the 2007 project of nearly 97% in 2008. FOF 254. When seeking re-approval of the Unit 2 project in 2009, Ameren's engineers explicitly stated they expected Unit 2 to perform "at least equal to, if not better than," Unit 1 and expected a 3–4% availability improvement. FOF 256. Mr. Meiners confirmed this at trial, testifying that the availability input used in financially justifying the Unit 2 outage to senior company executives was almost 97%. FOF 253.

The post-project data shows that Unit 2's availability actually reached 97.4% in the highest year after the project. FOF 260. As Ameren's trial witness Scott Anderson testified after reviewing Unit 2's historic availability statistics, the difference between the pre- and post-project performance was "night and day." FOF 261. Comparing the baseline to the post-project year, Mr. Koppe predicted an availability improvement of 2.8% due to the project alone, and Ameren actually got an improvement of 2.9%. FOF 259. The components at issue caused no availability losses after the project, as Mr. Koppe predicted. *Id.* As with Unit 1, the availability improvements far exceeded the small changes that would cause Unit 2 to emit 40 additional tons of SO_2.

The chart below shows the baseline availability losses caused by the components at issue (orange) and caused by all other factors (blue). After the work, there were no losses due to the new components and actual availability climbed to 97.4%. FOF 259–60.



Based on Mr. Koppe's prediction of regained availability, and using the method described above, Dr. Sahu calculated an expected increase of 415 tons per year of SO_2 in Unit 2 that would result from the availability improvement alone. FOF 258.

Separate from the expected increase in emissions based on availability improvements, Ameren also should have expected an emissions increase at Unit 2 based on capacity improvements. After the Unit 1 outage, Ameren saw a significant *capacity* gain as a result of the project. FOF 269. Ameren and Mr. Koppe both analyzed how a similar capacity gain would affect Unit 2's post-project operation.[7] [8]

There is no dispute that Ameren realized a gain in capacity, measured in megawatts ("MW"), at Unit 1. FOF 269–70, 274. Ameren expected similar improvement at Unit 2. *Id.* In

[7] In addition, Ameren replaced the low pressure turbine during the 2010 outage, which would also be expected to affect performance.

[8] Ameren argues that Mr. Koppe and Dr. Sahu's analyses double count the effect of deratings already accounted for in its availability analysis in its capacity analysis, but Dr. Sahu clearly presented separate emissions calculations for the availability and capacity increases. FOF 258, 302-303. *See also* US Br. at 26 n.16 (Doc. 838).

a series of company documents from Fall 2007 until the time of the overhaul, Ameren engineers repeatedly stated that significant capacity increases (of up to 30 MW) would result from the boiler work. FOF 269–78. That expectation was included in the documents presented to corporate executives seeking approval of the Unit 2 project. That expectation was even used to calculate how the project would impact Ameren's shareholders and ratepayers. FOF 158, 276. For instance, in the justification for the outage work that was presented to Ameren's executives, the company's engineers explained exactly what benefits they assessed in determining the projected value of the project. The first benefit listed is "30 MW gain in summer (3 mos), 20 MW gain balance of year *from reheater, economizer and APH [air preheater] investment*." Pl. Ex. 110 at AM-02465690 (emphasis added); FOF 277.

As he did for availability, Mr. Koppe independently studied the data and information produced by Ameren and reached a conclusion similar to what Ameren's engineers found before the Unit 2 outage. Mr. Koppe confirmed that pluggage had limited Unit 2's capability during the pre-project period and that Ameren should have expected at least 22 MW of increased capability due to the boiler work. FOF 279. Another 12-15 MW of capability would result from the new LP turbine. FOF 280. Dr. Sahu calculated that an 18 MW capacity increase due to the boiler project alone would increase emissions by 417 tons of SO_2. FOF 303.

The post-project data confirmed the results of Mr. Koppe's analysis. In fact, Ameren reported its improved capacity to MISO, the North American Electric Reliability Council, and the Missouri Public Service Commission, among other outside entities, each time attributing a major portion of the unit's capacity increase to the boiler work at issue. For example, Ameren responded to an inquiry from the Missouri Public Service Commission in a rate case related to the Unit 2 2010 outage. In defending its requested rate increase, Ameren stated that unit capability improved by 34 MW, of which 22 MW were restored capacity. FOF 288–89. Similarly, Ameren reported that Unit 2's *summertime* peak capability had increased to nearly 650 MW gross "due to work completed during the 2010 major outage (replacement of lower pressure turbines and *numerous boiler modifications*)." FOF 287 (emphasis added).

Ameren's post-project reports are quite similar to what Mr. Koppe found in reviewing the post-project data. Mr. Koppe first analyzed Ameren's "Plant Information" database and determined that Unit 2's capability had increased by 38 MW, from 615 MW during the pre-project period[9] to 653 MW afterwards. FOF 296–99. An almost identical increase is observed by comparing Ameren's "full load" test reports. The average capability reported by Ameren in those reports increased by 37 MW, when comparing baseline (620 MW) and post-project (657 MW) periods. FOF 295, 301.

Of the overall increase in capability, Mr. Koppe determined that about 23 MW of the increase were due solely to the component replacements and would require more coal to be burned. FOF 300. Ameren's documents show that it had reached the same conclusion. The predicted and actual capability increases Mr. Koppe reports are right in line with what Ameren used in its financial justification for Unit 2 (22.5 MW) and far more than the 1.7 MW that would result in 40 additional tons of SO_2.

Based on the performance improvements predicted by Mr. Koppe, Dr. Sahu calculated increases of more than 400 tons of SO_2 due to either the availability increase or the capacity increase alone. FOF 258, 303. Both the availability and capacity improvements Mr. Koppe predicted were borne out by actual data. FOF 237–38, 259–60. After the 2010 project, overall

[9] Because Ameren did not produce complete Plant Information data from before 2006, Mr. Koppe used January 2006-December 2007 for the pre-project period, since that was closest in time to Ameren's baseline.

emissions of SO_2 from Unit 2 increased by 2,171 tons per year. FOF 266. As a result, the actual emissions increase includes increases resulting from the availability increase and the capacity increase. Each is an order of magnitude larger than the PSD significance threshold.[10]

3. Dr. Hausman used Ameren's modeling to quantify the emissions impact from the projects

The conclusions of Mr. Koppe and Dr. Sahu are further supported by Dr. Hausman's analysis of Ameren's computer modeling efforts. Dr. Hausman is a modeler and market consultant with nearly 20 years of experience focused on the electric industry.

Ameren uses a sophisticated computer modeling program called ProSym to predict the operations of its generating fleet—including the Rush Island units—so it can plan accordingly. FOF 314–15. Ameren uses ProSym modeling for a number of things, including rate recovery proceedings before the Missouri Public Service Commission, fuel purchasing and planning, and informing capital investment decisions. FOF 315. Ameren has testified to the public service commission that its use of ProSym is "very well calibrated" and gives reliable projections of future unit performance. Plaintiff's Exhibit 439.

In the lead-up to the Rush Island overhaul projects—and in the normal course of its business—Ameren used ProSym to model and predict the Rush Island units' fuel needs ("heat input" in the industry parlance) for the years after the 2007 and 2010 major boiler outages. FOF 318–19, 329. Dr. Hausman performed two types of analysis based on Ameren's modeling. First, Dr. Hausman examined how varying specific inputs, such as the units' availability parameters or

[10] As noted in the discussion of Unit 1, even if I were to exclude testimony on actual emissions causation from Mr. Koppe and Dr. Sahu, which I will not, I can connect the dots myself to find the predicted—and realized—improvements caused the predicted—and realized—emissions increase.

maximum capacity values, would affect the model's projections for that unit's future performance. FOF 330–31. In effect, he investigated whether, and to what extent, the Rush Island units would actually use extra operating hours or extra capacity if the units were improved. The model that Ameren used routinely to simulate its units' operations showed that if Ameren increased the number of hours its Rush Island units were able to run, or if the company enabled the units to operate at higher output levels during those hours, then the units would take advantage of those performance enhancements, burning more coal and, as a result, emitting more pollution. FOF 332. In fact, the models showed that both a unit's capacity level and its availability are linearly related to the unit's projected coal consumption. *Id*.

The results of the ProSym runs confirm the admissions by Ameren's witnesses: performance improvements like capacity increases or availability gains would lead to additional operations and additional pollution. FOF 427–28. Dr. Hausman's sensitivity analyses quantify those relationships.

The following chart provides the results of Dr. Hausman's sensitivity analyses. Dr. Hausman ran several iterations of Ameren's ProSym model to identify what changes in forced outage rates, partial outage rates, and capacity would mean for coal consumption and pollution. FOF 334–41.

	Performance Measure	Δ Coal Consumption (Billion BTU)	Δ SO_2 Pollution (tons per year)
Rush 1	Forced Outage Rate (per 1%)	481	162
	Partial Outage Rate (per 1%)	408	138
Rush 2	Maximum Capacity (per 1 MW)	69	23
	Forced Outage Rate (per 1%)	566	189
	Partial Outage Rate (per 1%)	466	156

The demonstrated relationship between availability and capacity and emissions mean that a mere 0.3% improvement in availability[11] or a 1.7 MW increase in capacity is enough to cause the Rush Island units—modeled by Ameren in its regular business—to emit 40 additional tons of SO_2 pollution. FOF 333.

Dr. Hausman's second set of analyses compared the results of Ameren's modeling efforts, which included assumptions about improved unit availability and capacity beginning the year after the projects were performed, to model runs in which the Rush Island Units were not improved—that is, a scenario in which the outages that included the projects at issue in this case were never undertaken. FOF 342. These "with and without" analyses served to isolate the amount of the projected increase in unit operations and air pollution that was caused or enabled by Ameren's 2007 and 2010 outage work. FOF 343, 345. In other words, even though other factors contributed to unit operations and pollution, the comparison reveals how much of those emissions would not have been emitted "but for" the Rush Island performance improvements. Ameren—not Dr. Hausman—performed the engineering assessments of their outage work and folded those expected operational benefits into the company's modeling.[12] Dr. Hausman simply examined the result of those operational benefits on the units' projected operations. The

[11] These figures were based on Unit 1's partial outage rate results. Looking at Unit 2 or the forced outage rates would yield a smaller percentage triggering 40 tons of $S0_2$.

[12] Ameren argues that Dr. Hausman's with-and-without analyses are irrelevant because they do not compare baseline performance to projected performance. Rather, his analyses compare two future scenarios: the projected performance with the project to projected performance without the project. Although the comparison Dr. Hausman did is not the same as what is required of sources doing PSD calculations, Dr. Hausman's comparisons are relevant to this case, which requires a determination about causation. The purpose of Dr. Hausman's analysis was to examine the relationship between capacity and availability and that of generation and emissions. Conducting a with-and-without analysis provides useful causation information and is a standard industry method.

performance improvements Dr. Hausman identified in Ameren's ProSym input files are consistent with the performance improvements Mr. Koppe expected the Rush Island units would see over baseline levels based on his engineering analysis. The results of Dr. Hausman's analyses are summarized in the table below:

	Baseline Emissions	Modeled Performance Improvements	Projected Emissions	Total Increase	Result of Improvements
Rush 1	14,874 tpy	4.0% EAF	15,561 tpy	687 tons	562 tons
Rush 2	14,288 tpy	18 MW and 2.0% EAF	16,816 tpy	2,528 tons	746 tons

FOF 348–50, 353–54. These results show that Ameren's modeling would predict significant emissions increases at the Rush Island units as a result of the projects.

Ameren's expert witnesses confirmed at trial that the technique Dr. Hausman used is commonly used in the industry. FOF 344. Ameren's experts Michael King and Marc Chupka testified that they had done or recommended similar analyses in prior PSD enforcement cases—but did not do them here. *Id.*

4. **The evidence shows that efficiency improvements would not prevent emissions from increasing as a result of the projects**

Ameren argued that it expected unit efficiency to improve at Unit 2[13] and that this efficiency improvement would offset any overall increase in emissions. Before this litigation, however, Ameren made clear that it expected the improved efficiency to result in *more*

[13] Ameren has also argued that efficiency was expected to prevent an emissions increase at Unit 1. However, the project was not justified based on any efficiency improvements. It was justified based on outages and load limitations. FOF 145–47, 212. Moreover, while Ameren has now claimed some improvements in the unit's *net* efficiency, such an improvement means more of the unit's generation can be sent to the grid (as opposed to be used to run the plant itself) but does not reduce the amount of coal burned. FOF 117, 213, 351.

generation (greater total capacity) rather than less coal burned. In justifying the projects to management, Ameren's engineers predicted a small improvement (0.5%) in auxiliary load due to the boiler component replacements and a 15 MW increase in capacity due to the low pressure turbine. FOF 280. The 15 MW Ameren attributed to the turbine was *separate* from the 22.5 MW improvement attributed to the boiler components. Pl. Ex. 110; FOF 281. Similar improvements were reported by Ameren to the Missouri Public Service Commission—a 0.5% improvement due to the boiler component replacements and a 1.9% (12 MW) improvement due to the turbine replacement. FOF 291. Both types of improvements would result in producing more generation, but *not* in burning less coal. FOF 117, 213, 214, 280. Consistent with these reported expectations, Ameren did not incorporate *any* efficiency change in the 2010 fuel budget model run that it used as the projection for its NSR emissions calculation. FOF 401, 407. While Ameren later revised that run to reflect changed efficiency at Unit 2, it only did so *after* the project was long complete and the United States had filed this lawsuit. FOF 401. These revisions, which were made after the completion of the project and even after this lawsuit was filed, lack credibility. And even the revised projection showed an emissions increase that would trigger NSR after the analysis is adjusted to disregard Ameren's inappropriate application of the demand growth exclusion. *See* Subsection III.C.

The United States' experts took these potential efficiency improvements into consideration in performing their analyses. FOF 213–15, 279, 280, 300. Mr. Koppe explained that auxiliary load reductions would not impact gross efficiency, which is what matters for purposes of determining how much sulfur dioxide a unit will emit. FOF 117, 213. In his analysis of the turbine replacement at Unit 2, Mr. Koppe concluded that because the capacity increase at Unit 2 exceeded the efficiency improvement, the unit would ultimately still burn more coal even with the turbine replacement. FOF 214, 215, 280, 281, 300. Separately, Dr. Hausman did a variant of his with-and-without analysis that incorporated an efficiency increase that was even greater than the 2.4% improvement Ameren reported to the Missouri Public Service Commission. Dr. Hausman's analysis found improving efficiency had only a small effect on the projected increase related to the project, which was 696 tons of SO_2—still more than 15 times the threshold requirement. FOF 356.

Ameren concedes that efficiency actually got *worse* after the project compared to the baseline. Ameren blames a portion of the actual increase in pollution on the realized decrease in efficiency. Regardless of the cause for the unit's decline in efficiency, each hour of operations or each extra MW that is generated at the plant requires that much more coal—and results in that much more pollution. Ameren's argument has no impact on the United States' actual emissions theory because blaming increased emissions on unexpectedly declining unit efficiency does not change the fact that the units burned more coal and emitted more pollution than they otherwise would have without the boiler upgrades—and some of the emissions increase would never have occurred had Ameren decided not to perform those overhauls. Ameren did not claim that the efficiency decrease accounts for the entire post-project emissions increase. So even if some of the post-project actual increase was due to worsening efficiency, there was still an increase of emissions due to the projects.

Ameren argues that efficiency was *expected* to improve, so it was reasonable to expect less pollution, and then it argues that efficiency *actually* got worse, so the increase in pollution is unrelated to the projects. The evidence shows that the efficiency increase that Ameren claims to have expected would result in more MW, not less fuel burned. FOF 214, 215, 280, 281, 291, 300. And while the efficiency decrease that came after the project could explain part of the actual increase, it does not alter the fact that a substantial portion of the increase (far more than 40 tons) was related to the increased availability and capacity caused by the project. FOF 216.

5. **Conclusion: The emissions evidence shows an increase related to the projects should have been expected and actually occurred**

Ameren expected the projects to cause its highest period of post-project availability to rise well above the baseline availability for both units. The projects caused substantial availability increases. Ameren also expected and realized a post-project increase in capacity at Unit 2 from the challenged boiler work. Those expected and actual performance improvements were significantly larger than the small changes (an additional 21 full power hours or 1.7 MW) needed to cause a 40-ton increase in emissions.

The United States' experts approached the question of estimating the projected increases from different perspectives. Mr. Koppe and Dr. Sahu first focused on the expected incremental availability (and, for Unit 2, capacity) improvement, determined whether those improvements would be realized for the unit as a whole, and then directly calculated the tons of emissions associated just with those project-related improvements. Dr. Hausman took another approach. Using Ameren's modeling, he began with a projection that accounted for *everything* that Ameren expected at the units in the future, and then he isolated the amount of generation and pollution related to the project. Ameren criticized both approaches but never did its own calculation to show which of the additional tons of emissions were related to the projects.

Using these different approaches, Mr. Koppe and Dr. Sahu reached very similar conclusions to Dr. Hausman. Additionally, these experts' calculations were confirmed by the actual results, as shown in the two charts below:

UNIT 1	Koppe/Sahu	Hausman	Ameren's Documents	Actual Emissions
Δ EAF	3.8%	4.0%	4.0%	4.3%
Δ SO_2	608 tons	562 tons	[No PSD Analysis]	665 tons
FOF	227, 232	348 – 350	228 – 231	238, 243

UNIT 2	Koppe/Sahu	Hausman	Ameren's Documents	Actual Emissions
Δ EAF	2.8%	2.0%	3-4%	2.9%
Δ Capacity	18.1 MW	18 MW	22.5 MW	23 MW
Δ SO_2	415 (EAF) 417 (MW)	746 tons	2,531	2,170 tons
FOFs	251, 258, 303	353, 354	256, 276, 277, 402	260, 266, 300

The Koppe-Sahu results, Dr. Hausman's analyses, and the actual post-project data all establish that there is a significant net SO_2 increase of more than 40 tons that was caused by the projects. Based on the known facts that the Rush Island units are low-cost, baseload units, common sense compels the same conclusion: improving availability or capacity at baseload units like Rush Island will result in additional operations and pollution. Ameren's model confirms that relationship, as Dr. Hausman showed and Ameren's chief modeler confirmed in his testimony. FOF 329–41, 448. Other courts have recognized this relationship. *See* Subsection II.B.1 above (citing cases). Ameren should have expected a significant net emissions increase and should have obtained a permit before beginning work.

C. Ameren Also Violated Title V

Because I conclude the projects were major modifications, I also find that Ameren has violated Title V of the Clean Air Act.

Title V creates an operating permit program designed to collect all of a source's applicable requirements under the Clean Air Act in a single place. 42 U.S.C. § 7661c(a); *Ameren SJ Decision*, 2016 WL 728234, at *3 (quoting *Sierra Club v. Otter Tail Power Co.*, 615 F.3d. 1008, 1012 (8th Cir. 2010)).

Missouri's Title V program requires sources to obtain a permit with "all applicable requirements." 10 C.S.R. § 10-6.065(6)(C)1.A; *see also* 42 U.S.C. §§ 7661 - 7661c(a). By definition, applicable requirements include requirements under the New Source Review program. 10 C.S.R. § 10-6.020(2)(A)23; *see also Ameren SJ Decision*, 2016 WL 728234, at *24. In addition, Ameren's Title V permit prohibits major modifications without Ameren first obtaining a permit. FOF 456.

By performing major modifications without obtaining an NSR permit (and satisfying the associated requirements, including the requirement to operate best availability control technology to reduce emissions), Ameren violated both the requirement to obtain a permit with all applicable requirements and the permit prohibition against unpermitted major modifications.

III. AMEREN'S DEFENSES AND CRITIQUES OF THE UNITED STATES' EVIDENCE FAIL

A. The Projects were not Routine Maintenance

Ameren has asserted the routine maintenance, repair, and replacement defense. The routine maintenance exemption provides that projects do not constitute "major modifications" if they merely consist of routine maintenance, repair, or replacement activities. *See* 40 C.F.R. § 52.21(b)(2)(iii)(a); 10 C.S.R. 10-6.060(8).

Based on the evidence presented at trial, I conclude that the projects cannot be considered routine maintenance under the law. The Rush Island boiler refurbishments at issue were the most expensive boiler projects ever performed on an Ameren boiler. FOF 182, 183. They involved the redesign and replacement of major boiler components that were intended to improve the performance of the units and enable them to burn coal they were not originally intended to burn. FOF 47, 53, 62, 134, 138–47. They were the first such replacements in the history of each unit, are rarely done at any unit in the industry, and the combination of boiler replacements has rarely, if ever, been done in the industry. FOF 172, 174–76. Under the appropriate legal standards, every factor of the routine maintenance test weighs heavily against classifying the work as routine maintenance, repair, and replacement. Even Ameren's designated expert on routine maintenance, Jerry Golden, acknowledged at trial that these projects were not *de minimis*. FOF 164.

1. Legal standard

The standard for the routine maintenance, repair and replacement exemption in the NSR rules "is a narrow one and is generally limited to *de minimis* circumstances." *Ameren SJ Decision*, 2016 WL 728234, at *5. Ameren has the burden of proving the routine maintenance exemption applies. *Id.*

As I explained at summary judgment, to determine whether a defendant has met its burden of proving the routine maintenance exemption, courts examine the projects, taking into account the 1) nature and extent, 2) purpose, 3) frequency, and 4) cost of the activity to arrive at a common-sense finding. *Id.* at *4, *5 (citing *Wisconsin Elec. Power Co. v. Reilly*, 893 F.2d 901, 910-11 (7th Cir. 1990)). "Frequency [is] evaluated by considering the work conducted at the particular unit, work conducted by others in the industry, and work conducted at other individual units within the industry. In evaluating frequency, the most relevant inquiry is how often similar projects have been undertaken at particular units in the industry, not how many similar projects have been implemented industry wide." *Id*. at *5.

EPA has consistently interpreted the routine maintenance exemption as requiring review based on the "principle that a non-routine collection of activities, considered 'as a whole,' is not exempt under routine exclusion, even if individual activities could be characterized as routine." *Id.* at *8. For these reasons, as I stated at summary judgment:

> separate equipment or component replacements should be taken as a whole, i.e., multiple component replacements may constitute one 'project,' for purposes of the RMRR analysis, if . . . it appears that the work was done as part of one project. Under this common sense framework, I agree with EPA that whether the challenged work was planned for together, budgeted together, performed together, and undertaken for the same purpose are relevant to the inquiry.

Id.

2. The boiler refurbishments at each Rush Island unit constitute one project for routine maintenance purposes

All of the boiler component replacements were related in that they were planned together, budgeted together as capital projects, performed at the same time, and undertaken for the same purpose. As a result, I find that the work should be viewed together in determining whether it qualifies for the routine maintenance exemption.[14]

<u>The work was planned together.</u> There is no question that Ameren planned the component replacements together. When Ameren issued the contract documents to qualified bidders for the project, it consolidated all of the work in its contract specifications. FOF 133, 134. Ameren noted that the projects were combined to "gain efficiencies in procurement, design and installation" and described the air preheater replacement as "part of a Major Mechanical

[14] Even if I were to consider each major component replacement separately, I would still conclude that the projects were not routine maintenance under the weight of the evidence.

Work Package to include the Economizer, Reheater and Lower Slope portion of the boiler." FOF 132. Ameren described the "major boiler modifications for Rush Island 1 and 2" as follows:

> For several years we have been planning major refurbishment of the Rush Island 1 and 2 boilers, which have operated for nearly 30 years without replacing any of the major components. The major scope elements include the following major components which are experiencing an increase in tube leaks and fatigue issues, and have been redesigned to improve future operation and maintenance:
> - Reheater—redesigned for PRB coal
> - Economizer—redesigned for PRB coal
> - Lower Slope—ruggedized design to better withstand slag falls
> - Air Preheater—redesigned for ease of future basket replacement.

P. Ex. 6; FOF 139.

<u>The work was budgeted together.</u> As of December 2004, Ameren had created a preliminary capital budget for the replacement of the Unit 1 economizer, reheater, lower slopes, and air preheater as part of a single project. FOF 126. Even though Ameren prepared separate work orders for the two air preheater replacements, all the work was from Ameren's capital budget—not the operations and maintenance budget—and was budgeted for the same outage to be performed at the same time. FOF 130, 131, 181. Likewise, at Unit 2, Ameren consolidated the replacement of the challenged components when it sought bids from outside engineering firms to design, fabricate, and install those components. FOF 133.

<u>The work was performed at the same time.</u> It is undisputed that the components at issue were performed together during the same outages at Unit 1 and Unit 2. FOF 25, 169, 170.

<u>The work was undertaken for the same purpose.</u> Ameren's routine maintenance expert, Mr. Golden, agreed that the purpose of the work at each unit was the same. FOF 150–51. Mr. Golden confirmed Mr. Stevens' testimony that the purpose of the work at each unit was to eliminate pluggage and fouling of the economizers and reheaters and to eliminate future forced

and maintenance outages caused by tube leaks.[15] FOF 56–69, 145–47, 149. The United States' expert Mr. Koppe also explained that Ameren could completely resolve the capability restraints caused by pluggage only by replacing each of the components at issue during the same outage. FOF 53, 63, 196. Ameren's Jeff Shelton agreed. FOF 64.

3. The projects do not qualify for the routine maintenance exemption

a. Nature and extent

The 2007 and 2010 projects involved the replacement of major boiler components that are integral to the operation of the Rush Island Unit 1 and 2 boilers. The 2007 and 2010 projects took years to design and plan and required the special fabrication of components that were not otherwise available at the Rush Island plant. FOF 139, 164. The projects were far more extensive than the type of maintenance, repair, and replacement routinely performed at Rush Island and other coal-fired power plants. FOF 165–72. And it is clear from Ameren's documents that the company itself never considered these projects to be just "routine maintenance," as that term is understood in the industry; it considered them to be "major boiler modifications" or "major boiler refurbishments." FOF 50, 130, 139, 171.

Each of the boiler components was redesigned to eliminate the recurring problems associated with Ameren's switch to PRB coal. FOF 53, 134, 138–49. These design changes were intended to upgrade and improve the performance of the boilers. FOF 145–60.

Given the complexity of the replacements, the components were designed, engineered, and constructed by outside contractors, such as Alstom Power, the original manufacturer of the boilers. The work was well beyond the capacity of Ameren's own staff. FOF 128, 166.

[15] On Unit 1, the lower slopes were replaced to eliminate tube leaks and repair damage resulting from slag falls and erosion following the switch to PRB coal. FOF 52, 53, 56–59.

In contrast with routine maintenance, repairs, and replacements undertaken at utility plants, the projects required approvals of executives at the very highest level of the company, including Ameren's CEO. FOF 135–37.

The economizers, reheaters, and air preheaters each weigh hundreds of thousands of pounds and required construction of heavy equipment such as monorails and cranes. FOF 162, 167–68.

The 2007 outage for Unit 1 lasted 100 days and required more than 1,000 workers and 448,539 total hours of labor, of which 402,109 hours were performed by contractors. FOF 169. Ninety-one percent of the work done during the Unit 1 outage was performed by contractors. *Id*.

The 2010 outage at Unit 2 lasted approximately 100 days and required more than 350,000 hours of labor, of which 290,953 hours were performed by contractors. FOF 170. An average of 360 contractor staff worked two 10-hour shifts six days a week during the outage. *Id*.

The 2007 and 2010 overhauls were considered capital projects and were funded out of Ameren's capital budget rather than the operations and maintenance budget. FOF 181. As capital projects, these component replacements improved the value of the generating unit. FOF 180.

As a result, the nature and extent of these projects weighs heavily against a finding that these projects qualify for the narrow routine maintenance exemption.

b. Purpose

As noted above, the consistent purpose of the projects was to eliminate pluggage, fouling, and tube leaks. Ameren expected that tube leaks in the economizers and reheaters would be eliminated for at least 20 years. FOF 38, 145–47. By contrast, routine maintenance, repair, and replacement is performed to allow a unit or plant to continue to operate in its present condition.

See Doc. 227-2, Memorandum from Don Clay, Acting EPA Ass't Admin. (Sept. 9, 1988), at 3-4; Doc. 227-3, 2000 DTE Applicability Determination Detailed Analysis, at 11.

The replacement of these major boiler components allowed the units to operate hundreds more hours than they could in the baseline period at a higher capacity by eliminating tube leaks, load limitations, and operational constraints. The purpose of these projects indicates that the work was far from routine.

c. Frequency

Even though the most relevant inquiry is how often similar projects have been undertaken at particular units in the industry, for each of the three inquiries under the frequency factor, the inquiry weighs heavily against a finding of routineness.

Frequency at the unit. None of the components at issue had been replaced at these units before. FOF 173. The components were replaced after 31 years of service at Unit 1 and 33 years of service at Unit 2. FOF 4, 174.

Frequency at individual units within the industry. The components at issue are very rarely replaced at any plant. FOF 174–76. Ameren's expert confirmed this point. Mr. Golden agreed that the typical life of a reheater is about 30 years, the typical life of a primary economizer is about 35 years, and the typical life of the lower furnace is about 40 years. FOF 174. Mr. Golden also testified that complete air heater replacements (including the rotor and all baskets), like the ones done at Rush Island, are not done frequently at any unit. *Id*. This evidence, coming from Ameren's expert, demonstrates that replacing the components at issue is rarely done at individual units within the industry.

Work conducted by others in the industry. Mr. Golden testified about a list he has complied of 18,300 projects undertaken at coal-fired power plants. The list includes projects that

Mr. Golden identifies as capital projects costing more than $100,000. *Id*. As an initial matter, the relevance of Mr. Golden's list to this case is weak because Mr. Golden has been unable to identify *any* coal-fired unit in the electric utility industry that has replaced the economizer, the reheater, the lower slopes, and the air preheater together. *Id*. Boiler refurbishments like the ones at Rush Island are not common in the industry.

Regarding air preheater replacements, Mr. Golden identified 35 replacements of regenerative air preheaters going back to the 1970s. [16] FOF 176. By his count, that is less than 2 percent of the coal-fired units in the country. However, Mr. Golden was unable to say whether those 35 instances were complete replacements or similar to those at Rush Island. *Id*. Even if they were, a replacement that takes place at less than 2 percent of the units going back to the 1970s is not common in the industry.

As a result, the frequency factor weighs heavily against these projects being routine.

d. Cost

The projects at issue were the most expensive capital projects ever done at Rush Island. Each project cost substantially more than the entire operations and maintenance budget for the plant for an entire year. FOF 177, 178, 182. Grouping the replacements at each unit together, the two projects were among the most expensive boiler projects ever undertaken at any of Ameren's plants. FOF 183.

Based on the undisputed facts regarding the costs of these projects, the cost factor also weighs heavily against these projects being routine.

4. Conclusion: the projects cannot be considered routine

[16] Even for the claimed 35 air preheater replacements, Mr. Golden was unable to testify that all were complete replacements or that all the replacements were comparable to the air preheater replacements at Rush Island. FOF 177.

Ameren has not satisfied its burden of proving that the Rush Island projects fall within the narrow routine maintenance exemption. The 2007 and 2010 major boiler outages were unprecedented events for Rush Island Units 1 and 2—they were the centerpieces of the "most significant" outages in plant history. FOF 172. A common sense finding weighing the nature and extent, purpose, frequency and cost of the projects reveal them to be far from *de minimis* activities contemplated by the exemption. Ameren's expert agreed and testified at trial that these projects were not *de minimis* activities. As a result, Ameren's routine maintenance defense fails.

B. The Emissions Increases Cannot Be Set Aside Based on the Demand Growth Exclusion

Ameren also asserts the "demand growth exclusion," set forth at 40 C.F.R. § 52.21(b)(41)(ii)(c), as a defense to liability. As the United States Court of Appeals for the District of Columbia explained in *New York v. EPA*, "the regulation establishes two criteria a source must meet before excluding emissions from its projection: (1) the unit could have achieved the necessary level of utilization during the [baseline period]; and (2) the increase is not related to the physical or operational change(s) made to the unit." 413 F.3d at 33 (quotations omitted). "The two prongs are distinct. Satisfying the 'could have accommodated' prong is necessary but not sufficient to justify application of the exclusion, and emissions that 'could have been accommodated' at baseline are not per se 'unrelated.'" *Ameren SJ Decision*, 2016 WL 728234, at *21.

Additionally, as stated at summary judgment, "the burden is Ameren's to prove that the demand growth exclusion applies." *Id.*

1. Ameren's experts confirm that demand was not projected to—and did not—cause the pollution increases at Rush Island

Fundamental to an invocation of the demand growth exemption is that demand *on the unit* increases. But in this case just the opposite happened, as the data shows—and Ameren's expert witnesses conceded.

A unit's "utilization" is a measure of how much of its available capacity the unit is called on to use. The measure serves to reflect market demand on a specific unit. FOF 377. As Mr. King explained, a declining utilization factor means demand on the unit is decreasing. FOF 378. As a result, when the utilization factor is declining, an increase in pollution *cannot* be the result of demand. *Id.*

As far as the actual emissions case is concerned, Mr. King and Ms. Ringelstetter both testified that the utilization factor for the Rush Island units actually *decreased* after the projects. FOF 378–80. The declining demand that the units actually experienced after the projects prevents Ameren from asserting a successful demand growth argument for the actual emissions increase shown in the data.

Ameren's application of the demand growth exclusion also fails for the expectations case. Ameren's testifying expert Marc Chupka looked at the utilization factor data leading up to each project and concluded that "[i]t would be reasonable to assume a constant utilization factor for projecting future emissions" following the boiler upgrades at issue in this case. FOF 208. Ms. Ringelstetter agreed. She testified that the utilization of Unit 1 was projected to remain basically constant, and, though utilization of Unit 2 was projected to increase somewhat (about 2%), the increase paled in comparison to the projected increase in emissions (over 15%). FOF 380. A constant utilization factor means static demand on the units. If that demand is constant, it cannot be the cause of an emissions increase. Regardless, even the marginal projected increase in Unit 2's utilization factor cannot account for the substantial emissions increase that Ameren's modeling and calculations projected. *Id.*

2. Ameren's evidence does not address what portion of the units' projected or actual emissions increases were "unrelated" to the projects

The evidence Ameren presented in support of the demand growth defense generally falls into two categories: (1) evidence that regional demand for electricity was generally going up during the years surrounding the Rush Island projects, and (2) calculations regarding how much generation (and pollution) the units "could have accommodated" during the baseline periods. The central problem for Ameren's defense is that these showings, while necessary to the company's proof, are insufficient to establish that the demand growth exclusion applies to any specific "portion" of its projected emissions increases, as required by the rule. *Cf.* 40 C.F.R. § 52.21(b)(41)(ii)(*c*); *see also* 40 C.F.R. § 52.21(r)(6)(i)(*c*) (requiring operators to document and describe certain PSD analyses, including "the amount of emissions excluded under [the demand growth exclusion] and an explanation for why such amount was excluded"). Ameren has failed to establish a correlation between rising regional demand and any specific impact on unit performance in order to show what portion of its projected emissions increases are "unrelated" to the projects at issue in this case.[17]

[17] Ameren's theory on demand growth appears to be that, if it can prove emissions were related to demand, then the emissions cannot be related to the projects. This rests on the false assumption that an effect can only have one cause. Because pollution, like any effect, can have more than one "but for" cause, it is not enough for Ameren to simply point out that some of its projected and actual increases in emissions are related to the presence of sufficient market demand for Rush Island power. Ameren disputes the relevance of the restaurant analogy argued by the United States and used by the Court at summary judgment. *See Ameren SJ Decision*, 2016 WL 728234 at *10 n.17. But the restaurant analogy remains useful. To be sure, a meal

The first category of Ameren's evidence—its various system load forecasts—fails to connect meaningfully to projections of unit operations because increases in system demand do not necessarily translate into increases in unit operations. As Ameren's witnesses testified, during the baseline period, the units operated as baseload units and operated whenever they were available. As a result, they were usually fully-loaded during "on peak" hours when system demand was at its highest. FOF 371–72. If the units were generally maxed out anyway, increases in system demand would have little effect on unit operations.[18] That is reflected in Ameren's expert testimony on unit utilization, discussed above. Moreover, as Dr. Hausman testified, Ameren's ProSym modeling efforts showed just how disconnected unit operations were from system level demand. Ameren's load forecasts were inputs into its modeling runs, and they reflected the company's expectation that system load was growing on the order of 1% a year. But the output files from those very same runs reveal Ameren's computer simulations projected that generation from the Rush Island units would increase immediately following the outage and then remain relatively flat. FOF 373. Ameren seems to suggest that rising regional demand for electricity—like a rising tide—would lift operating levels at its units. The evidence clearly establishes otherwise.

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served to a restaurant customer is "related" to the customer's decision to order it (customer demand); but that does not mean that the meal is "unrelated" to the restaurant having an open table or the chef's preparation of the food.

[18] Ameren witness Jaime Haro noted that, for baseload units like Rush Island, increases in system demand would mean the units still ran at high levels most of the day, but they might ramp down a little later each day or turn up to full load a little earlier each morning. FOF 370. The marginal increases in demand on the "shoulder" hours may have been attributable to system level demand, but Ameren made no attempt to quantify just what portion of its emissions projections were made up of these marginal shifts. As a result, Ameren cannot meet its burden of proof on this defense.

Ameren's second category of evidence, presented through its expert Sandra Ringelstetter, is a series of calculations describing how much SO_2 pollution the Rush Island units "could have accommodated" during their respective baseline periods. This, too, fails to address how any specific portion of its projected emissions increases is unrelated to the projects at issue. It does not address any portion of the units' projected emissions *at all*. While varying somewhat in the details, all of these calculations involve picking a pollution rate the units achieved at some limited point during the baseline period (sometimes a month, sometimes a week, sometimes a discontinuous set of hours taken from across the 24-month baseline period), and then multiplying that emissions rate by the unit's baseline equivalent availability levels. Since EAF is a measure of available hours, and since its emissions rate is related to a unit's load levels,[19] these calculations essentially assume that the unit would run flat out, at some very high level of operations, through day and night, for nearly two continuous years. Ameren then concludes that, since demand was going up and its "could have accommodated" calculations result in more emissions than any projected increase in this case, *all* projected emissions increases can and should be excluded from the NSR liability calculation.

Ameren's "could have accommodated" calculations are fundamentally flawed. For example, they employ unreasonably-high emissions rates and rely on applicability determinations divorced from the operational realities of electric utilities. But even if Ameren's "could have accommodated" calculations were reliable, the calculations cannot—as a structural matter—say anything about whether the projected emissions from the units are *related* to the projects at hand. Ameren's "could have accommodated" calculations consider neither the

[19] Despite Ms. Ringelstetter's testimony to the contrary, hourly emissions are directly related to hourly heat input in her own analysis, Ringelstetter Test., Vol. 11-B, 85:15–86:3, and the relationship between heat input and unit load level is "more or less linear." *Id.* at 85:9 – 11.

projects at issue nor the projected emissions in any way. At best, the calculations have something to say about only one prong of the demand growth exclusion, which is not sufficient to establish the exclusion applies.

3. Ameren's other demand growth arguments fail

Ameren made two additional arguments at trial in support of its demand growth defense. First, Ameren argued that "unit-level demand" is not the focus of the test, and that instead, the demand growth exclusion focuses directly on "systemwide demand." In other words, Ameren argues that the problem of translating system demand into demand on the unit and changes in unit operations is not required by the rule itself. For that proposition, Ameren cites the 1992 WEPCO Rule Preamble where the demand growth exclusion was first introduced. The passage does not support Ameren's argument; in fact, just the opposite:

> [W]here increased operations are in response to independent factors, such as system-wide demand growth, which would have occurred and *affected the unit's operations* even in the absence of the physical or operational change, such increases do not result from the change and shall be excluded from the projection of future actual emissions.

57 Fed Reg. 32,314, 32,326 (1992). As a result, the regulations themselves establish that EPA has always required an operator to show whether—and to what extent—demand would "affect the unit's operations" before the demand growth exclusion could be applied.[20]

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[20] Ameren cites various other authorities in its post-trial brief to support its argument that evidence of increasing systemwide demand is sufficient to establish the demand growth exclusion. Ameren misreads each of these authorities, ignoring paired language clarifying that the relevant inquiry requires consideration of how demand affects the units at issue. The demand growth standard is clear. In situations like these, "where [a] proposed change will increase reliability, lower operating costs, or improve other operational characteristics of the unit, increases in utilization that are projected to follow can and should be attributable to the change." 61 Fed. Reg. 38,250, 38,268 (1996).

Ameren's second argument was presented through the testimony of Ms. Ringelstetter. Specifically, Ameren argued that any performance changes or any emissions increases following the Rush Island modifications would be unrelated to those boiler modifications. This conclusion is unsupported and was offered for the first time at trial.

Until the summary judgment ruling, Ameren and its experts declared that it did not really matter *what* the project was so long as the unit, during the baseline, "could have accommodated" the projected emissions. As the head of Ameren's Environmental Services Department testified in Rule 30(b)(6) deposition testimony, "The emissions that the unit was capable of accommodating prior to the outage would be totally unrelated to . . . any activities that occurred on the outage. So just by the nature of the scope, the emissions are unrelated." Whitworth Rule 30(b)(6) Depo. Test. 38:4-12; *see also Ameren SJ Decision*, 2016 WL 728234, at 9 (describing Ameren's argument that "'unrelated' means any emissions increases a unit could have accommodated at baseline"). And when Ms. Ringelstetter originally performed her "could have accommodated" calculations, she declared that was the only step necessary to establish that the exclusion applied. She testified at her deposition that even assuming the performance improvements she recognized in Ameren's modeling files were the result of the boiler upgrades, it would not have changed her analysis, her calculations, her considerations, or her conclusions in any way. FOF 438.

Ameren's theory is inconsistent with the plain language of the regulations, the case law, and my summary judgment decision holding that the two prongs of the exclusion are distinct. *See Ameren SJ Decision*, 2016 WL 728234, at *11. After my summary judgment ruling, Ameren adjusted its theory and attempted to show that neither the capacity increase experienced at Unit 2 nor the availability increase experienced at either unit was related to the boiler upgrade work at issue in this case. Not only is such a conclusion contrary to the Ameren's internal engineering and economic documents, the pre- and post-project analyses provided by Ms. Ringelstetter, on which Ameren bases its relatedness arguments, are flawed.

Ms. Ringelstetter's capacity analysis begins by relying on inapplicable pre-project values. Instead of comparing projected future operations to actual, past operations, she looks at modeling inputs from previous years. Though those earlier modeling efforts might generally be expected to reflect the unit's actual operations around that time, the capacity values used here present a particular problem: Ameren uses its capability tables to develop unit capacity inputs, and for half of the baseline at each unit, the capacity tables were "unrealistically high."[21] FOF 431–32. That means the capacity increase Ameren expected to see and did see following the Unit 2 work was about twice what Ms. Ringelstetter saw. That increase cannot be attributable to turbine work alone, as Ms. Ringelstetter claims. FOF 431–32; *cf.*, *e.g.*, FOF 304.

Ms. Ringelstetter's analysis also discounts the observed availability increases post-project as being too small to be meaningful. Essentially, Ms. Ringelstetter argues that the increases are "in the noise," so there is no increase at all. But the evidence shows that just a 0.3% availability improvement could result in 40 additional tons of SO_2 at Rush Island. FOF 191. Ameren's

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[21] In January and February of 2006—and in middle of the baseline periods—Ameren decided to update its capability tables to come up with more accurate predictions. Pl. Ex. 157 at AM-02743289. For the Rush Island units, that meant substantially reducing the projected unit capabilities as operating data showed that the units were struggling to perform as expected for many months of the year. U.S. FOF 119. Recognizing this, and using "historical operating data along with design criteria," Ameren updated its capability tables and substantially reduced the Rush Island numbers in order to "generate more realistic capability ratings for all of [the company's] fossil units." Pl. Ex. 260 at AM-00091465. The new numbers dropped the average annual capability ratings for the units by about 12 MW. Compare Pl. Ex. 157 with Pl. Ex. 260. So Ms. Ringelstetter's baseline capability number is substantially inflated since almost half of the numbers there were "unrealistically high." U.S. FOF 432.

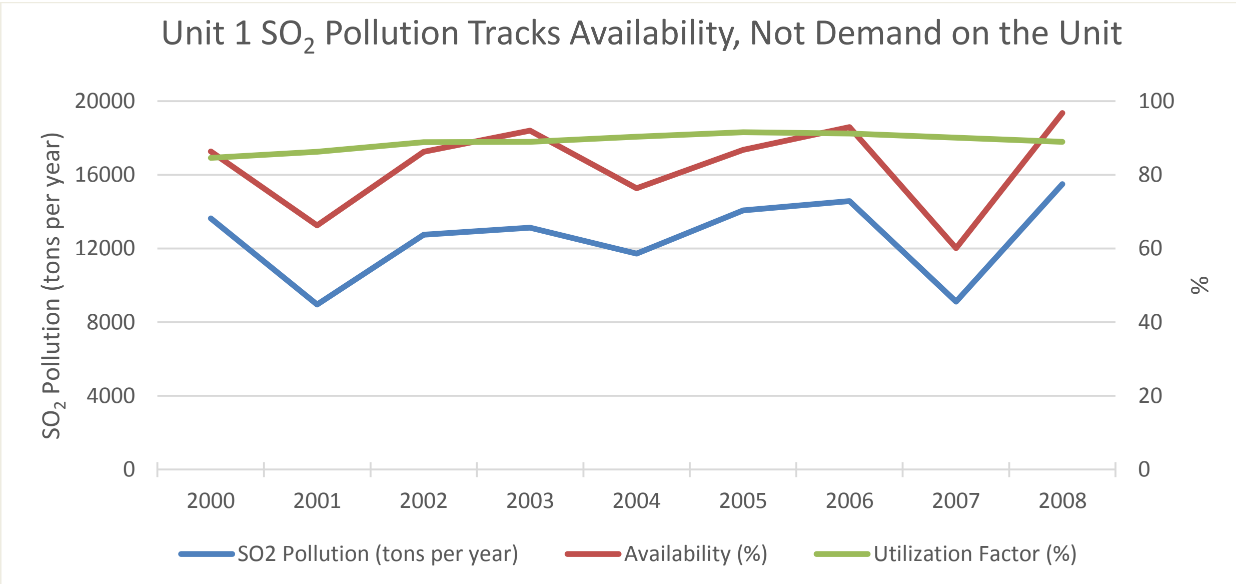
economic justifications were calculated to a tenth of a percent. FOF 104, 148. Ms. Ringelstetter's opinion also disregards the fact that Ameren projected long-term averages in its computer modeling and that specific years, as is relevant under the PSD analysis, might be as much as 2% or 3% higher than the inputs presented in the ProSym inputs. FOF 257. The important inquiry here is the size of the availability gain, which the evidence noted in Subsection II.B has shown to be about 3–4%. As Dr. Hausman testified, that kind of gain would lead to additional operations and pollution. To the extent Ms. Ringelstetter's testimony disregards these gains, her testimony is simply not credible.

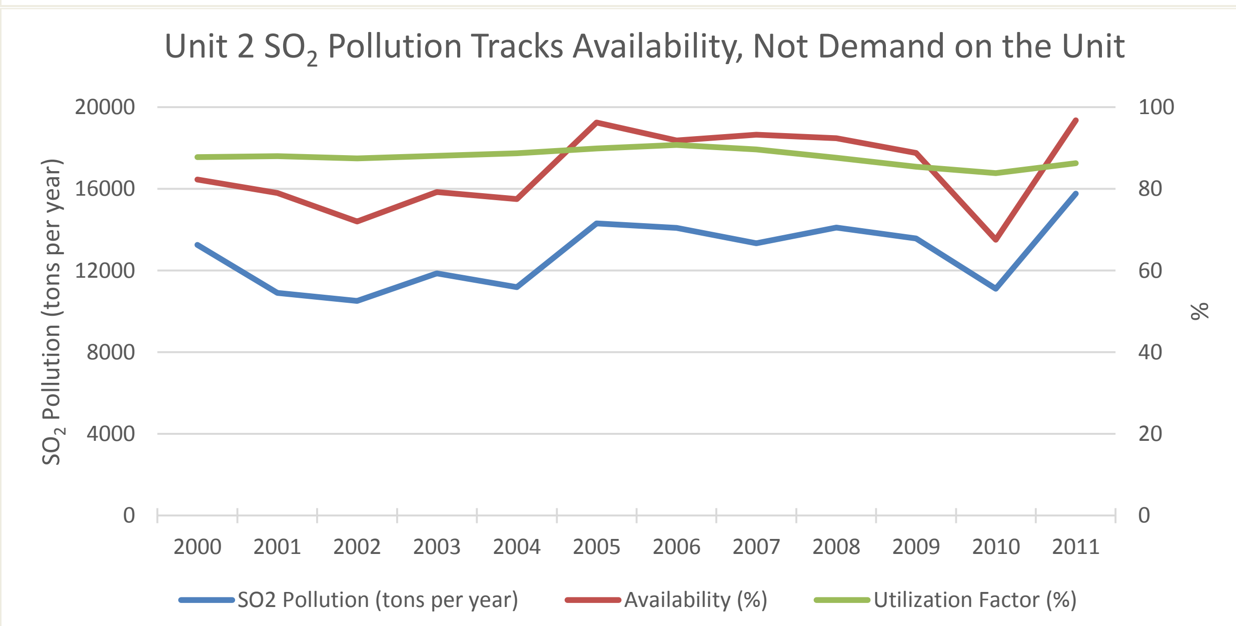
4. Emissions resulting from operations that would not have been possible but for the boiler upgrades cannot be considered "unrelated" to those boiler upgrades

Ameren's demand growth defense fails to address whether projected emission increases are related to the projects at issue. No matter how Ameren calculates the quantity of emissions it could have emitted had demand for electricity stayed high through the night, it does not address the reality that the units' real opportunities to sell more (and emit more) came by expanding their ability to operate when the demand is high—and when their units are generally maxed out—during the day. FOF 370–71. If there were baseline hours where the unit could not operate because of outages caused by the components at issue, any post-project recovery of those hours would be related to the project. Mr. Koppe found there were 246 outage hours for Unit 1 and 146 outage hours for Unit 2 caused by the projects in the baseline. FOF 240, 263. As described in Subsection II.B of my Conclusions of Law, both Mr. Koppe and Ameren concluded that those hours would be recovered and used in the post-project period. For those hours, the units went from unable to operate to able to operate. Demand did not cause that change; the units already operated every hour they could. That change resulted from $70 million of capital work. As I explained at summary judgment, when a unit "undergoes modifications that allow it to run more during the daytime hours tha[n] it could before, it cannot be said that the increased emissions were merely a coincidence or unrelated to the modification." *Ameren SJ Decision*, 2016 WL 728234, at *10.

Ameren's witness admitted that changes in unit capacity or availability would lead to changes in operations and pollution, FOF 427–28, and the company justified the cost of the projects on precisely those kinds of performance improvements. FOF 146, 277. Dr. Hausman specifically examined how performance improvements at the units translate into coal consumption and pollution, and the result is predictable: when the units are better able to supply electricity, they do so, and they burn more coal in the process, emitting more pollution. *See* Subsection II.B.2.c.

Moreover, the company's data reflects the straightforward relationship between the Rush Island units' performance abilities and their pollution levels. As discussed earlier, "[u]tilization is a variable that describes how much of the [unit's] available capacity the unit utilizes," and that in turn reflects the influence of all of the "market considerations" like system demand and market price that can impact unit operations. FOF 377. A unit's equivalent availability factor, on the other hand, reflects the engineering condition of the unit—how well it has been maintained and whether it stands ready to generate whenever needed. FOF 94. The graphs below show that Ameren's historical emissions data reflects the reality that Rush Island operations were driven by its engineering condition (measured by its availability) more than any market fluctuations (measured in its utilization). These graphs show SO_2 emissions, availability, and utilization factor at Units 1 and 2, respectively. They were the subject of testimony by Dr. Sahu and Mr. King and are based on data compiled by Dr. Sahu and Ms. Ringelstetter.[22]





[22] Ameren moved to exclude the graphs as not properly disclosed. For reasons I discuss below (*see* Section on Evidentiary Issues), I will deny Ameren's motion as it relates to these graphs. Notably, the charts were also used in the United States' summary judgment briefing, Doc. 609 at p. 20, and Ameren's David Strubberg presented a similar chart, comparing availability and generation, at the 2008 State of the System Meeting. FOF 202.

Reviewing these charts at trial, Ameren's testifying expert Michael King conceded that there was a relationship between availability and pollution. FOF 381.

Ameren argued that being forced to translate system level demand into an effect on unit operations would turn the analysis from an annual emissions focus to an hour-by-hour assessment, which is not contemplated by the regulations. That argument fails for two reasons.

First, just as a restaurant owner knows the ebb and flow of customers throughout the lunch and dinner rushes, Ameren knew that Rush Island generally ran hard throughout the day and ramped down somewhat at night. In this context, Ameren's employees noted that derates resulting from pluggage in the units' boiler components were costing the company as much as $25,000 a day. FOF 112. A company does not lose earnings when it has available capacity that it could dip into at a moment's notice; it loses earnings when it cannot provide the generation it would otherwise be able to sell for a profit. *See, e.g.*, FOF 112, 274 (Williamson email). And when Ameren justified the substantial expense of the boiler overhauls at the Rush Island units, the company quantified the benefit of recovering availability and capacity. Again, those benefits can only be considered "benefits" of the projects if the units would not have otherwise been able to operate that often or at those levels. *See, e.g.,* FOF 146. Documents like these reflect the general truth—without necessitating an hour-by-hour data review—that the units were limited, the problems were expected to be fixed, and the units would operate more as a result.

Ameren's argument that NSR cannot require sources to perform an hour-by-hour look at operations is disingenuous when its own ProSym software—which it uses regularly in the course of its business and runs hundreds if not thousands of times each year—solves the dispatch problem on an hour-by-hour basis for every year it is told to do so. FOF 317. That model makes it easy to isolate how performance improvements would interact with other market constraints to determine unit operations on an hour-by-hour basis and further determine how those hourly operations translate into annual generation and pollution numbers. Dr. Hausman did just that, and the results showed a straightforward relationship: more capacity or more availability led to more generation and more pollution. PSD requires sources to consider "all relevant information" in analyzing whether emissions will increase; it does not contemplate sources ignoring known, relevant information just because it might be unfavorable. Section 52.21(b)(41)(ii)(a). Ameren had the relevant information, and that information showed that the Rush Island units' performance would improve, resulting in increased generation and emissions.

As I have previously ruled, increases made possible by performance improvements must be attributed to the project and cannot be covered by the demand growth exclusion. *See* Subsection II.B.1.

C. Ameren's New Source Review Analyses Are Fatally Flawed and Cannot Provide Safe Harbor from Liability

Ameren's emissions calculations are not reasonable analyses under the PSD rules and therefore do not show that Ameren should not have expected an emissions increase.

1. Ameren does not have a legitimate process for assessing PSD applicability

First, Ameren's position relies on a fundamental misunderstanding of the PSD program. Ameren offered the testimony of Mr. Boll and Mr. Whitworth at trial to describe how Ameren determined whether a project might cause an emissions increase. Both witnesses testified that the company looked to whether the unit's *potential* emissions were expected to increase.[23] FOF 391. The company employee actually charged with performing the PSD analysis for Unit 2

[23] Mr. Boll used the term maximum continuous rating. FOF 391. As Ameren explained in its earlier briefing, that term is a measure of a unit's potential emissions. Doc. 542 at 5-6.

confirmed Ameren's reliance on the wrong metrics when he testified that any improvements in availability were "irrelevant." FOF 396, 397(d).

Ameren's method of assessing PSD does not comply with the rules, EPA's instructions, or case law. The rules explicitly direct a source to compare projected emissions to baseline emissions, both measured in tons per year. 40 C.F.R. § 52.21(b)(41), (48). As noted above, both EPA and the courts that have interpreted the PSD program have explained that "[i]f an increase in hours of operation is caused or enabled by a physical change, the increased hours must be included" in the projection. *Duke Energy 2010*, 2010 WL 3023517, at *5. EPA has brought enforcement actions since 1999 based on improvements in availability that lead to increases in annual pollution. Ameren's testifying expert conceded that EPA's enforcement approach has been "well-known in the industry" since 1999. FOF 219.

By focusing on potential emissions, Ameren ignores my ruling on Ameren's first motion for summary judgment. In motions practice, Ameren argued that the United States had to show a "modification" under the Missouri SIP before turning to the issue of whether the projects were "major modifications." Doc. 542 at 1-2. Ameren argued that modification status was controlled by *potential* emissions. *Id*. I rejected that argument. Doc. 711. As Ameren argued at summary judgment, "'modification' and 'major modification' are distinct terms with separate characteristics under the SIP." Doc. 542 at 5. At trial, however, Ameren described its internal analysis as focused solely on the first test, not the major modification test actually before the Court.

For the reasons described in Subsection II.B.2 of my Conclusions of Law, if Ameren had considered how the actual performance changes would affect generation, it would have expected and found emissions increases related to the project.

Second, Ameren failed to coordinate between the engineers who planned and performed the projects and the environmental services employees charged with assessing NSR applicability. Michael Hutcheson, who performed the NSR analysis for the Unit 2 project, reported that he learned about the project from his boss and his boss's boss but never talked to the engineers working on the project. FOF 397(a).

On the other side of this divide, engineering leaders at Ameren like Robert Meiners and David Strubberg testified that they had no involvement in assessing whether the projects triggered PSD. FOF 393. Mr. Meiners testified that as plant manager, he was "accountable" for ensuring that Rush Island complied with environmental regulations. *Id*. Despite that accountability, Mr. Meiners testified that he had never been involved in a single discussion about whether to seek a New Source Review permit for any project:

> Q. Even though you were plant manager, though, you had no involvement at all in the decision of whether to seek a New Source Review permit for either of the projects at issue in this case, right?
>
> A. I was not involved with that. We had an environmental department that took care of those kind of items. I was not involved.
>
> Q. And by "not involved," I mean, you didn't have a single discussion with anyone about the decision of whether to seek a New Source Review permit?
>
> A. No, I did not.
>
> Q. And, in fact, throughout your career at Ameren you've never had a single discussion with anybody about whether to seek a New Source Review permit for any project, right?
>
> A. No, I have not.

Tr. Vol. 7-B, 64:6-20.

The project justification packages that Ameren regularly put together as part of the work approval process included a checkbox asking whether the proponent had assessed

"Legal/Environmental" risks. FOF 388. But as one engineering manager testified, he could not "recall that box ever being checked" and had no idea what it meant. FOF 389. Each project had to be approved by a series of managers and executives, even the company CEO and board of directors. FOF 135–37. But the Environmental Services Department, charged with assessing NSR applicability, was not asked to approve the projects.

As a result, Ameren's PSD process suffered from two major flaws: the employees charged with assessing applicability started with an incorrect understanding of the law and lacked a meaningful understanding of the facts of the projects. In addition to these procedural flaws, for the reasons that follow, the actual analyses Ameren did "conduct" (for Unit 2 only) provide no basis for finding that Ameren could have reasonably expected the project would not significantly increase net emissions.

2. Unit 1

Ameren concedes that it performed no numerical calculation for the Unit 1 project.[24] FOF 391. Whatever qualitative analysis may have been done at the time cannot shield Ameren from liability now. Nor can the post-hoc analysis offered at trial by testifying expert Sandra

[24] Ameren argued for the first time in its post-trial brief that it was not required to perform a numerical calculation at Unit 1 because the provision of the 2002 Reform Rules requiring such calculations be performed was on remand at the relevant time. Ameren's argument fails. Even though a portion of the rule was on remand at the time, the Missouri SIP and EPA still required sources to maintain these records. *See* 71 Fed. Reg. 36,486, 36,487-88 (June 27, 2006); *see also* US Resp. Br. (Doc. 838) at 47-48. Moreover, as Ameren itself points out, the United States has not brought a record-keeping case and is not seeking judgment that Ameren failed to maintain the necessary records. Rather, the relevant issue is whether Ameren reasonably should have expected emissions to increase because of the projects. Whether Ameren performed a numerical calculation at all is certainly relevant to that inquiry and will, accordingly, be considered.

Ringelstetter, who used an inapt modeling run and incorrect application of the demand growth exclusion.

As an initial matter, there is no contemporaneous evidence that Ameren performed any assessment of the Unit 1 project. Mr. Boll testified that Ameren performed a qualitative emissions analysis for the projects in 2005. FOF 390, 391. But this analysis did not even rise to the back-of-an-envelope level—there is no written record of any such analysis. Moreover, because Mr. Boll and Mr. Whitworth made clear they only considered the maximum continuous rating of the unit, any qualitative analysis they did "conduct" did not comply with NSR requirements and therefore was not reasonable under the law. *Id.*

The post-hoc analysis performed by Ms. Ringelstetter does nothing to support Ameren's belief that emissions would not increase at Unit 1. Despite presumably having access to scores of ProSym modeling runs that projected Unit 1's post-project operations, Ms. Ringelstetter selected a run with two key flaws. First, according to her trial testimony, the run actually overstated emissions, so she adjusted it downward. FOF 454. Notably, other runs had no such issue, and Ameren itself never saw the need to adjust the run. FOF 454. Second, the run intentionally depressed output from Unit 1 for the full five years following the project based on the potential for the unit to provide ancillary services.[25] FOF 448, 449, 453. Ameren did not provide any evidence to support this assumption other than the testimony of Ms. Ringelstetter herself. Ms. Ringelstetter testified the modeling assumption was "entirely appropriate" and yet did not offer any document or specific fact to support that conclusion. She never even

[25] Ancillary services are services other than simple electric generation that utilities provide to keep the electric grid operating reliability. FOF 439.

mentioned ancillary services, spinning reserves, or regulation hours in her expert report. FOF 451. Moreover, the limited evidence in the record contradicts her opinion:

1. The only evidence that Ameren may have expected to provide some ancillary services with the Rush Island units around the time the boiler upgrades were performed is a short-term contract between Ameren Missouri and its Illinois affiliates. But that contract does not require anything specific of the Rush Island units in particular; in fact, it gave Ameren Missouri flexibility to provide the services from a number of different units. FOF 442.

2. Whatever effect the contract may have had on operations of the Rush Island units, the effect was never expected to last. The contract was never intended to extend beyond the inauguration of MISO's regional ancillary services market (originally scheduled in 2008 and then delayed to January 2009). FOF 440. Ameren's witnesses all agreed that once MISO implemented its ancillary services market the Rush Island units would not be providing such services at it does not make economic sense to hold back such cheap, reliable sources of generation. In fact, Ameren's head modeler told the Missouri Public Service Commission in that it did not make sense to model those services because they were based on a "short-term contract that will end when the MISO ancillary service market begins." FOF 445.

Selecting a run which depressed output for five years by modeling ancillary services at the Rush Island Unit 1 that—if ever they had an impact on operations—would last no more than two years after the project runs afoul of the regulations' requirement to "consider all relevant information" and use the highest year of post-project emissions. 40 C.F.R. § 52.21(b)(41)(ii)(*a*).[26]

3. Unit 2

While Ameren did at least perform numerical analyses for Unit 2, these analyses are no more compelling than its qualitative analysis for Unit 1.

As an initial matter, even though PSD analyses should be completed before beginning construction, Ameren did not complete any numerical analysis for Unit 2 until after the project work started. FOF 398-401. Ameren began its "Original" analysis at the end of 2009, which

[26] After using an inappropriate modeling run to obtain projected emissions, Ms. Ringelstetter misapplied the demand growth exclusion, as described in Subsection III.B of my Conclusions of Law.

relied on a January 2010 modeling run. By the time that analysis was done, the project was underway and it was too late for Ameren to comply with the law if a permit was required. Moreover, the work had been *approved* for four years at that point. The work was first approved in 2005 and then reassessed in a process that culminated with the final approval from the Board of Directors in August 2009. FOF 400.

Mr. Hutcheson testified at trial that the Original Unit 2 emissions calculation was one of about two dozen requested at the same time by Ameren's legal department. FOF 399. The projects to be assessed were a mix of past and future projects. *Id.* For Unit 2, the request came well after the project had been fully approved. FOF 400. This type of afterthought analysis (even if it had been finished just before the start of construction instead of just after) does not serve as a reasonable emissions calculation or prevent a finding of liability, particularly where the analysis fails to account for the company's actual expectations of performance improvements, as discussed below.

Ameren's "Amended" Unit 2 analysis is not helpful because it was not performed until even later and was only performed well after the project was completed, after Ameren received the Notice of Violation from EPA, after this lawsuit was filed, and only upon the request of Ameren's in-house counsel. FOF 401, 405-406. Ameren's in-house counsel asked the Environmental Services Department to perform this post-project amended "expectations" analysis to include the results of the amended EDF case that counsel had previously asked Mr. Hutcheson to run. That case was modeled to include additional efficiency improvements that had been left off from the Original run. FOF 401-407. Because the Amended analysis was performed under these circumstances and presumably for the purpose of this litigation, any credibility the analysis might otherwise have is severely diminished. Ameren's expert, Mr.

King, testified that he would not perform an NSR analysis based on a modeling run that was created just for NSR purposes, agreeing that in using such a run, a source runs the risk of looking like it was "cooking the forecast" to project no emissions increase. FOF 408.

In addition to these procedural flaws, the analyses Ameren actually did conduct suffered from considerable substantive flaws. Ameren's Original analysis failed to fully incorporate the improved availability the company expected after the project. The modeling run used for the projection assumed 95% availability for Unit 2 after the project. FOF 257, 410. But, as discussed in Subsection II.B.2 above, Ameren expected that the best years after the project would be 2–3% higher than that, based on its experience with Unit 1's record availability in 2008. The justification seeking ultimate approval for the project was based on an availability of nearly 97%. The regulations require Ameren to consider the highest year of emissions. 40 C.F.R. § 52.21(b)(41)(i). By limiting availability to 95%, Ameren failed to perform a reasonable analysis under the PSD rules.

Even without fully accounting for the project's effects, Ameren's analysis would have shown an NSR-triggering increase except for what Ameren excluded based on its capable of accommodating analysis. In calculating the capable of accommodating number, however, Ameren posited that the unit could have run all available hours *and* that it could have polluted at its 95th percentile emissions rate. FOF 412. The effect was that the total capable of accommodating number was more SO_2 per year than Ameren had emitted since 1995 (when Acid Rain rules were taking effect). FOF 417. Had Ameren used a more realistic emissions rate, its own analysis would have shown that it was *not* capable of accommodating the projected increase. FOF 413–16, 419, 420.

The post-hoc analysis by Ms. Ringelstetter begins with the same flaw as Mr. Hutcheson's calculation. Ms. Ringelstetter also failed to properly account for the project. She used the same modeling run as Mr. Hutcheson and as a result did not account for Ameren's actual, expected highest year of availability and "business activity." In addition, she attributed the entire capacity gain modeled in that run to the turbine, despite the fact that Ameren expected increased capacity resulting from the boiler work as well, as described in Subsection II.B.2 above. FOF 430.

Finally, Ms. Ringelstetter did not do her own analysis of whether the increased emissions projected by the model were related to the project.[27] FOF 437. She simply assumed they were not. FOF 437–38. Because her assumptions are incorrect, Ms. Ringelstetter's analysis is not persuasive.

EVIDENTIARY ISSUES FROM TRIAL

At trial and in post-trial briefing, both parties moved to exclude, strike, or deem irrelevant certain testimony or exhibits. For the reasons stated below, to the extent I have relied on evidence and testimony challenged by either party in my findings of fact and conclusions of law set out above, the parties' motions are denied. To the extent I have not relied on the challenged evidence and testimony, the parties' motions are denied as moot.

I. AMEREN'S MOTIONS TO STRIKE TESTIMONY AND EVIDENCE

A. Ameren's Motions to Strike Mr. Koppe and Dr. Sahu's Testimony and Evidence Concerning the Causation of Actual Emissions Increases

In two motions filed during trial (Doc. 787 and 793), and in a motion filed along with its post-trial briefs (Doc. 832), Ameren moved to exclude certain testimony of Mr. Koppe and Dr. Sahu, along with related exhibits that were admitted into evidence during trial concerning

[27] Ms. Ringelstetter's analysis of the emissions that unit was capable of accommodating is also flawed, for the reasons described in Subsection III.B of my Conclusions of Law.

causation of the actual emissions increases. Ameren argues the testimony concerning the causation of the actual emissions increases are new, undisclosed opinions.

While Ameren argues that Mr. Koppe and Dr. Sahu's opinions are new, there is no dispute that both Mr. Koppe and Dr. Sahu (1) analyzed the actual post-project data in their reports, the attachments, and their work papers, and (2) stated that the projected increases actually materialized. Both Mr. Koppe and Dr. Sahu disclosed in their reports that they analyzed post-project actual data. Likewise, their opinions about how the projects enable increased availability and contribute to increases in emissions were discussed in their reports and at their depositions. Ameren argues that because neither expert's report states their opinions in the precise words that Ameren thinks they should have used, the reports did not give notice that the projects at issue actually caused increases in emissions. But the notice required of expert opinions is not so formulaic. While undisclosed expert opinions are inadmissible, Rule 26(a)(2)(B) "contemplates that the expert will supplement, elaborate upon, explain and subject himself to cross-examination upon his report." *Thompson v. Doane Pet Care Co.*, 470 F.3d 1201, 1202-1203 (6th Cir. 2006) (holding the district court erred in excluding the testimony of an expert accounting witness because he failed to recite in his report that his opinion was based on "generally accepted accounting principles," the phrase used in the contract at issue in the case; further holding there was no authority for the "mechanical and formalistic ruling" that an expert's opinion must state such "magic words"); *see also Wood v. Robert Bosch Tool Corp.*, No. 4:13 CV 01888 TCM, 2015 WL 5638040, at *8 (E.D. Mo. 2015) (denying in part a motion to strike new expert opinion statements because the offered statement "clarifies [the expert witness's] earlier information, does not contradict it, and should not be surprising to Defendant or its experts"). For these reasons, and those set out in the United States' post-trial brief (*see*

Doc. 831 at 50-56) and its opposition to Ameren's motion to strike (*see* Doc. 836), Mr. Koppe and Dr. Sahu's challenged opinions are not "new opinions." Ameren had sufficient notice of both the United States' actual emissions case and of Mr. Koppe and Dr. Sahu's opinions.

Moreover, Ameren cannot show that it was prejudiced by the challenged testimony or the admission of the exhibits. The evidence the United States presented to show that the actual emissions increases were caused by the projects was also presented in the context of its expectations case regarding the expected causes of projected emissions increases, so the challenged testimony is in part cumulative evidence. Additionally, Ameren had the opportunity both during pre-trial discovery and during cross-examination at trial to test those opinions. *See* Doc. 831 at 50-56. Finally, Mr. Koppe's testimony regarding Ameren's full load tests and related exhibit 928 do not prejudice Ameren. Exhibit 928 is merely a summary exhibit of Ameren's own capability data. Ameren itself argued at summary judgment that such summary evidence containing simple mathematic calculations (averaging pre-project and post-project data and comparing them) is admissible. Moreover, Mr. Koppe considered the full load tests along with numerous other materials to reach his conclusion that the capacity increase was due to the projects, making the exhibit cumulative evidence.

Accordingly, I find that the opinions were sufficiently disclosed and that Ameren has not suffered any prejudice from the admission of that testimony because it had notice and opportunity to test it and because it is in part cumulative evidence. As a result, I will not strike Mr. Koppe and Dr. Sahu's testimony on the causation of the actual emissions, Mr. Koppe's testimony concerning the increased MW capability at Unit 2, or the related challenged exhibits.

B. Ameren's Motion to Strike Dr. Hausman's Testimony Criticizing Ms. Ringelstetter's Opinions

Ameren has also moved to strike certain testimony of Dr. Hausman, arguing that he offered new opinion testimony at trial when he criticized Ms. Ringelstetter's analysis. Ameren asks me to strike Dr. Hausman's testimony from the record per Fed. R. Civ. P. 26. In the challenged testimony, Dr. Hausman testified about the different ProSym runs he and Ms. Ringelstetter analyzed, which included a discussion of why he chose the particular run selected. This testimony is not a new opinion that should be stricken under Rule 26. Rather, as Rule 26 contemplates, Dr. Hausman's testimony merely clarified his previously disclosed opinion, explaining why he chose the ProSym run he used and how the different runs he and Ms. Ringelstetter used factored into the different conclusions each expert drew. *Thompson*, 470 F.3d at 1202-1203. Moreover, Ameren has not shown it was prejudiced by this testimony, as it had always had the opportunity to test the basis of Dr. Hausman's analysis. *See also* Doc. 836 at 17 (discussing the lack of prejudice to Ameren).

As a result, I will not strike Dr. Hausman's testimony concerning the differences between his and Ms. Ringelstetter's analyses because it is not undisclosed testimony and Ameren cannot show it was prejudiced by the testimony.

II. THE UNITED STATES' MOTION TO CURTAIL RE-LITIGATION OF THE LAW OF THE CASE

In its post-trial brief, the United States also raised an evidentiary issue, renewing its motion in limine to curtail Ameren's re-litigation of the law of the case. *See* Doc. 757; Doc. 758 at Section IV.B. The United States argues that three categories of evidence Ameren presented at trial are irrelevant and should be excluded:[28] (1) applicability analyses or permitting documents that were generated after the projects at issue in this case and involving different facilities operating under separate state implementation plans at different types of sources, (2) testimony from EPA or state agency staff regarding the operation and application of regulatory provisions, and (3) PowerPoint presentations and other pamphlets discussing NSR regulations.

Ameren argues that these categories of evidence are relevant, not to establish the reasonableness of any legal interpretation, but to establish the reasonableness of its engineering judgments, emissions analyses, and predictions of the future.

To the extent I rely on the challenged evidence in my findings and conclusions above, I will deny the United States' motion. To the extent I have not relied on the challenged evidence, the motion is denied is moot.

CONCLUSION

For the reasons set out above, I find that the United States has established by a preponderance of the evidence that Ameren violated the PSD and Title V provisions of the Clean Air Act. The 2007 project at Rush Island Unit 1 and the 2010 project at Rush Island Unit 2 were each major modifications under the PSD provisions of the Clean Air Act. Ameren violated the requirements of the PSD program by failing to obtain a preconstruction permit and install best available pollution control technology, among other requirements. Ameren also violated Title V of the Clean Air Act and its operating permit by performing a major modification without obtaining the required permit and by not including applicable requirements in its operating

[28] The United States seeks to exclude the following exhibits and testimony: Ameren exhibits BQ, PQ, PV, QJ, QS, RB, RC, RD, RE, RG, RH, RN, OY, OZ, PA, PF, and deposition testimony from David Campbell, Trial Tr. Vol. 12, 9:10-11:8; Gregg Worley, Trial Tr. Vol. 12, 4:2-5:22; and James Stewart, Trial Tr. Vol. 12, 11:4-13:2.

permit applications. As a result, I will enter a finding of liability against Ameren. A status conference will be set to address remedies.

Accordingly,

IT IS HEREBY ORDERED that Defendant Ameren Missouri is found liable under the Clean Air Act, 42 U.S.C. § 7401 *et seq*.

IT IS FURTHER ORDERED that a status conference to address remedies is set for **Wednesday, February 15, 2017 at 11:00 a.m.** in courtroom 16-South.

IT IS FURTHER ORDERED that the United States' Motion in Limine to Curtail Ameren's Re-Litigation of the Law of the Case #[757] is **DENIED** per my rulings above.

IT IS FURTHER ORDERED that Ameren's Motion to Treat Certain KDHE Produced Documents as Highly Confidential During Trial #[778] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Bar Robert Koppe's New Causation Opinions #[787] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Bar Dr. Ranajit Sahu's New Opinions #[793] is **DENIED** as moot.

IT IS FURTHER ORDERED that Ameren's Motion to Strike EPA's New Expert Opinion Evidence and Related Trial Exhibits #[832] is **DENIED** per my rulings above.

IT IS FURTHER ORDERED that the Parties' Joint Motion to Correct Clerk's Exhibit List #[829] is **GRANTED**.

RODNEY W. SIPPEL
UNITED STATES DISTRICT JUDGE

Dated this 23rd day of January, 2017.

United States Court of Appeals
For the Eighth Circuit

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No. 19-3220

____

United States of America

Plaintiff - Appellee

Sierra Club

Intervenor - Appellee

v.

Ameren Missouri

Defendant - Appellant

Chamber of Commerce of the United States of America; American Chemistry Council; America's Power; Missouri Chamber of Commerce and Industry; National Association of Manufacturers; National Mining Association

Amici on Behalf of Appellant(s)

____

Appeal from United States District Court
for the Eastern District of Missouri - St. Louis

____

Submitted: December 16, 2020
Filed: August 20, 2021

____

Before SMITH, Chief Judge, LOKEN and MELLOY, Circuit Judges.

SMITH, Chief Judge.

Ameren Missouri ("Ameren") appeals an adverse judgment of the district court in a Clean Air Act (CAA) enforcement action brought by the United States of America, acting at the request of the Administrator of the United States Environmental Protection Agency (EPA) (hereinafter, EPA or "government"). Ameren argues that the district court erroneously found it liable for not obtaining permits for projects at its Rush Island Energy Center ("Rush Island") and, as a result, assessed liability under the applicable federal regulations. In addition, Ameren maintains that the district court ordered legally flawed injunctions at both Rush Island and at a different plant, Labadie Energy Center ("Labadie"). We affirm the district court's liability determination, but we reverse in part the remedial portion of its order concerning the Labadie plant and remand for further proceedings consistent with this opinion.

I. *Background*

A. *Statutory and Regulatory Background of the CAA*

"Congress enacted the Clean Air Act Amendments of 1970 seeking to guarantee the prompt attainment and maintenance of specified air quality standards." *Sierra Club v. Otter Tail Power Co.*, 615 F.3d 1008, 1011 (8th Cir. 2010) (quotations omitted). In enacting the CAA amendments, Congress "directed EPA to devise National Ambient Air Quality Standards (NAAQS) limiting various pollutants, which the States were obliged to implement and enforce." *Id.* (quotation omitted). The New Source Performance Standards (NSPS) program was a key part of the CAA's regulatory scheme. *Id.* The NSPS program "required EPA to develop technology-based performance standards designed to limit emissions from major new sources of pollution." *Id.* (quotation omitted). Both newly constructed facilities and modified facilities with increased emissions constitute "[n]ew sources." *Id.* "It is 'unlawful for any owner or operator of any new source to operate such source in violation of' applicable performance standards." *Id.* (quoting 42 U.S.C. § 7411(e)).

The NSPS program, however, "did too little to 'achieve the ambitious goals of the 1970 amendments.'" *Id.* (quoting *Env't Def. v. Duke Energy Corp.*, 549 U.S. 561, 567 (2007)). "Merely setting emissions limits failed to improve air quality in those areas that had already attained the minimum standards of the NAAQS because polluters had no incentive to diminish emissions below the established limits." *Id.* As a result, in 1977, Congress amended the CAA "to add the 'Prevention of Significant Deterioration' (PSD) program, which seeks to ensure that the 'air quality floor' established by the NAAQS does not 'in effect become a ceiling.'" *Id.* (quoting *Sierra Club v. Thomas*, 828 F.2d 783, 785 (D.C. Cir. 1987)).

The PSD program limited construction of major emitting facilities with specified preconditions. 42 U.S.C. § 7475(a). "The term 'construction' when used in connection with any source or facility, includes the *modification* . . . of any source or facility." *Id.* § 7479(2)(C) (emphasis added). "The term 'modification' means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." *Id.* § 7411(a)(4).

The PSD program prohibits the construction of a major emitting facility unless preconditions are satisfied. One precondition is that the proposed facility obtain a permit setting forth applicable emission limitations. *Id.* § 7475(a)(1). Another precondition is that "the owner or operator of such facility demonstrates . . . that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of" prescribed air quality standards. *Id.* § 7475(a)(3). The PSD program also requires the owner or operator to install "the best available control technology for each pollutant subject to regulation . . . emitted from, or which results from, [the proposed] facility." *Id.* § 7475(a)(4). The "'best available control technology' (BACT) . . . . is not a particular type of technology." *Otter Tail*, 615 F.3d at 1011 (quoting 42 U.S.C. § 7475(a)(4)). Instead, the BACT "is an 'emission limitation based on the maximum degree of reduction of each pollutant subject to regulation . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable' for the facility in question." *Id.* (alteration in original) (quoting 42 U.S.C. § 7479(3)).

Only *major* modifications to emitting sources are subject to PSD review. *Ala. Power Co. v. Costle*, 636 F.2d 323, 399 (D.C. Cir. 1979). "Major modification means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase . . . of a regulated NSR [New Source Review] pollutant . . . ; and a significant net emissions increase of that pollutant from the major stationary source." 40 C.F.R. § 52.21(b)(2)(i).

For projects that only involve "existing emissions units," the EPA applies what it calls the actual-to-projected-actual applicability test. *Id.* § 52.21(a)(2)(iv)(c).[1] To apply this test, the "baseline actual emissions" must first be calculated. "Baseline actual emissions means the rate of emissions, in tons per year, of a regulated NSR pollutant . . . ." *Id.* § 52.21(b)(48).

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[1]This test provides: "A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions . . . and the baseline actual emissions . . . , for each existing emissions unit, equals or exceeds the significant amount for that pollutant . . . ." *Id.*

> Next, the "projected actual emissions" must be calculated by determining the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12–month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

Id. § 52.21(b)(41)(i). An "owner or operator of the major stationary source . . . [must] consider all relevant information" to calculate "the projected actual emissions." *Id.* § 52.21(b)(41)(ii)(a). "[A]ll relevant information . . . include[s] . . . historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans under the approved State Implementation Plan . . . ." *Id.* But the owner or operator "[s]hall exclude" from the projected actual emissions "that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions . . . and that are also unrelated to the particular project, including any increased utilization due to product demand growth." *Id.* § 52.21(b)(41)(ii)(c). The "exclu[sion] [of] increases stemming from unrelated demand growth" is referred to as "the 'demand growth exclusion.'" *New York v. EPA*, 413 F.3d 3, 16 (D.C. Cir. 2005).

Finally, the baseline actual emissions calculation is subtracted from the projected actual emissions calculation to determine if the difference between the numbers is "significant." 40 C.F.R. § 52.21(a)(2)(iv)(c). A table in the regulations sets forth the numeric thresholds that are considered "significant" for each regulated pollutant. *Id.* § 52.21(b)(23)(i). If the difference in the projected actual emissions and the baseline actual emissions is significant, *see id.*, then a permit is required before beginning construction on the project. *Id.* § 52.21(a)(2)(iii).

The actual-to-projected-actual test is distinguishable from "a potential-to-potential test," which "compare[s] past potential emissions with future potential emissions." *New York*, 413 F.3d at 17. "[T]he plain language of the CAA indicates that Congress intended to apply NSR to changes that increase actual emissions instead of potential or allowable emissions . . . ." *Id.* at 40.

B. *Missouri's State Implementation Plan*

"The PSD program is primarily implemented by the states through 'state implementation plans' (SIPs)." *Otter Tail*, 615 F.3d at 1011 (citing 42 U.S.C. § 7471). While "[s]tates have broad discretion in designing their SIPs," their "plans must include certain federal standards." *Id.* The EPA reviews and approves States' SIPs. *Id.* at 1011–12.

Missouri expressly incorporated the EPA's PSD regulations into its SIP ("Missouri SIP"). *See* Mo. Code Regs. Ann. tit. 10, § 6.060(8)(A) (2007) ("All of the subsections of 40 CFR 52.21, other than [certain subsections], are hereby incorporated by reference."). The EPA approved Missouri's SIP, explaining that "the provisions of § 52.21 supersede the state provisions for purposes of the PSD program." Approval and Promulgation of Implementation Plans; State of Missouri, 71 Fed. Reg. 36,486-02, 36,487 (June 27, 2006); *see also id.* at 36,489 ("This revision also incorporates by reference the other provisions of 40 CFR 52.21 as in effect on July 1, 2003, which supersedes any conflicting provisions in the Missouri rule. Section 9, pertaining to hazardous air pollutants, is not SIP approved.").

C. *Title V Program*

In addition to the CAA's PSD program, "the CAA . . . require[s] each covered facility to obtain a comprehensive operating permit setting forth all CAA standards applicable to that facility." *Otter Tail*, 615 F.3d at 1012 (citing 42 U.S.C. § 7661a(a)). The operating permits "incorporate into a single document all of the CAA requirements governing a facility. Similar to other CAA programs, Title V is implemented primarily by the states under EPA oversight. In states with EPA approved programs," the state permitting authority issues the Title V permits. *Id.* (citations omitted). These permits "are subject to EPA review and veto." *Id.* The EPA has approved Missouri's operating permit program under Title V of the CAA. This program is incorporated into the Missouri SIP. *See* Mo. Code. Regs. Ann. tit. 10, § 6.065 (2007).

D. *Factual Background and Procedural History*

This case involves Ameren's Rush Island power plant, which includes two coal-fired electric generating units, Units 1 and 2. These units began service in 1976 and 1977. They were grandfathered into the PSD program. They do not have air pollution control devices for sulfur dioxide. Rush Island currently emits approximately 18,000 tons of sulfur dioxide per year. Small performance improvements or increases in unit availability can result in a 40-ton increase in sulfur dioxide. For the Rush Island units to emit more than 40 tons of sulfur dioxide, it takes only an availability of 0.3 percent or an additional 21 hours of operation at full power.

By 2005, problems with Units 1's and 2's major boiler components forced Ameren to frequently take the units out of service. This made the units underperform and reduced the amount of electricity Ameren could generate and sell from the units. Ameren decided to replace the problem components with new, redesigned components. Ameren, however, did not do any quantitative PSD review for Unit 1's project and belatedly performed PSD review for Unit 2's project. Ameren proceeded with the projects without reporting its planned modifications to the EPA, obtaining the necessary permits, or installing pollution controls. To replace the major boiler components, Ameren took Unit 1 offline in 2007 and Unit 2 offline in 2010. Each unit was completely offline for three to four months to complete the projects. Ameren spent more than $20 million per project.

By replacing the failing components with new, redesigned components, Ameren expected unit availability to improve by much more than 0.3 percent, allowing the units to operate hundreds of hours more per year after the projects. Ameren expected to use that increased availability (and increased capacity for Unit 2) to burn more coal and generate more electricity. Unavoidably, the units would also emit more sulfur dioxide pollution.

As Ameren expected, its replacement of the failing components resulted in increased availability at Units 1 and 2 by eliminating hundreds of outage hours per year. And, Unit 2's capacity increased. The units ran more, burned more coal, and consequently emitted hundreds of tons more sulfur dioxide per year because of the operational increases.

The government filed suit against Ameren in response to the projects. It alleged that Ameren violated the CAA, the Missouri SIP, and Ameren's Rush Island Plant Title V Permit by performing major modifications on Units 1 and 2 without obtaining the necessary permits, installing pollution control technology, or otherwise complying with all applicable requirements.

1. *Liability Phase*

a. *Summary Judgment*

The district court bifurcated the proceedings into a liability phase and a remedy phase. During the liability phase, the district court issued two summary-judgment orders. In the first summary-judgment order, the district court rejected Ameren's argument that the major-modification test set forth in the federal regulations did not provide the relevant PSD liability test because the Missouri SIP elsewhere separately defined *modification* to mean that "the source's *potential* emissions would significantly increase." *United States v. Missouri (Ameren I)*, 158 F. Supp. 3d 802, 808 (E.D. Mo. 2016) (emphasis added). According to Ameren, the government could not establish liability because it never alleged that "the [Rush Island] projects increased the units' *potential* emissions." *Id.* (emphasis added). In rejecting this argument, the court first explained that "the PSD rules impose their own independent, stand-alone applicability provisions in Section (8) of the Missouri SIP (incorporating EPA's PSD rules set out at 40 C.F.R. 52.21)." *Id.* at 809. The court reasoned that "the PSD-specific applicability language should trump the general applicability language in Section (1) of the [Missouri] SIP." *Id.*

The court next cited the "well-established" "regulatory and statutory history of the PSD rules" as leaving "no doubt that the federal PSD rules are focused on 'major modifications' which are based on actual emissions determinations," not potential emissions. *Id.* at 810. The court found "most persuasive[] [that the] EPA's approval of the SIP provided that the CAA and the program requirements as set out in 40 C.F.R. § 52.21 would supersede any conflicting provisions in the state SIP." *Id.* (citing Approval and Promulgation of Implementation Plans; State of Missouri, 71 Fed. Reg. at 36,489).

Finally, the district court concluded that Ameren urged an interpretation of the SIP that would conflict with the PSD rules and, in the court's view, "render a portion of the PSD rules superfluous." *Id.*

In its second summary-judgment order, the district court addressed causation and "the PSD program's demand growth exclusion." *United States v. Ameren Mo. (Ameren II)*, No. 4:11-cv-77-RWS, 2016 WL 728234, at *9 (E.D. Mo. Feb. 24, 2016). According to the district court, "two main criteria . . . determine whether a major source of pollution must obtain a PSD permit. First, there must be a physical change, and second, that change would be expected to cause a significant net increase in actual emissions." *Id.* The demand growth exclusion is relevant to the second criteria—"how to determine whether the physical changes would have caused a significant net emissions increase, and if so, whether any of the increased emissions may be excluded from review under the 'demand growth exclusion.'" *Id.* The district court rejected Ameren's proposed interpretation of the exclusion as applying to "any emissions increases a unit could have accommodated at baseline." *Id.* Instead, the court held "that the demand growth exclusion requires a showing that the unit 'could have accommodated' the emissions at baseline *and* that . . . those increases were unrelated to the project." *Id.* at *11. The court also held that "while it remains the EPA's burden to prove that Ameren should have expected the projects to cause an increase in emissions, the burden is Ameren's to prove that the demand growth exclusion applies." *Id.*

Also in the second summary-judgment order, the district court addressed Ameren's argument that "because EPA brought suit *after* the challenged projects' completion," it was "limited to an 'actual increase' theory." *Id.* at *13. Under Ameren's actual-increase theory, the EPA would have to show that "the Projects actually caused emissions to increase" to establish Ameren's liability. *Id.* By contrast, under "an 'expectations' theory," the EPA could establish liability by showing "that Ameren 'should have expected' the Projects to increase emissions." *Id.* The court held that the government could proceed on the expectations theory. *Id.* at *13–16.

Additionally, the court considered Ameren's argument that the government had to "come forward with admissible evidence of what a reasonable power plant operator or owner would expect, and its failure to do so [was] fatal to EPA's expectations theory case." *Id.* at *18. But the court agreed with the government "that no special standard of care evidence is required for the factfinder to be able to determine whether a reasonable power plant operator or owner would have expected the projects to cause a significant emissions increase"; instead, "the PSD regulations themselves . . . guide the factfinder's determination." *Id.*

Finally, the court rejected Ameren's argument that the court "lack[ed] subject matter jurisdiction to hear EPA's [Title V] claim that Ameren [was] operating under an inadequate or deficient permit." *Id.* at *24.

b. *Trial*

Subsequently, the district court held a trial on the merits. After trial, the district court entered an order setting forth its factual findings and legal conclusions. *See United States v. Ameren Mo. (Ameren III)*, 229 F. Supp. 3d 906 (E.D. Mo. 2017). The court concluded that Ameren's Rush Island overhauls were major modifications that triggered PSD pollution-control requirements. The district court found that "[t]he emissions evidence show[ed] [that] an increase related to the projects should have been expected and actually occurred." *Id.* at 997 (emphasis omitted). The court identified categories of evidence that "all establish that there is a significant net [sulfur dioxide] increase of more than 40 tons that was caused by the projects." *Id.* at 998.

First, the court identified "[t]wo key—and undisputed—characteristics of the Rush Island units." *Id.* at 988. The first characteristic was that "the Rush Island units are big sources of pollution." *Id.* The second characteristic was that "the Rush Island units are 'baseload' units" that are "cheap sources of electricity" and "operate as much as they can." *Id.* According to the court, "[t]hese two facts lead to a logical conclusion [that] if the Rush Island units are upgraded so they *can* generate more electricity, they *will*. Performance improvements have a direct impact on annual generation and pollution levels." *Id.*

Second, Robert Koppe, a power plant performance expert, opined that the Rush Island's plant availability increased because it replaced "these problematic components." *Id.* at 989. Thereafter, "Dr. Ranajit Sahu, a permitting engineer and expert for the United States, took Mr. Koppe's findings on expected improved availability and used them to calculate the expected additional pollution that would result from the improvements." *Id.* at 990. He "calculated an expected increase in emissions of 608 tons of [sulfur dioxide] post-project for Unit 1." *Id.* And, "[b]ased on Mr. Koppe's prediction of regained availability, . . . Dr. Sahu calculated an expected increase of 415 tons per year of [sulfur dioxide] in Unit 2 that would result from the availability improvement alone." *Id.* at 992.

Third, Dr. Ezra Hausman, a modeler and market consultant with 20 years' experience in the electric industry, explained that the "sophisticated computer modeling program" that Ameren used "to model and predict the Rush Island units' fuel needs . . . for the years after the 2007 and 2010 major boiler outages" "showed that both a unit's capacity level and its availability are linearly related to the unit's projected coal consumption." *Id.* at 994, 995. Thus, "if Ameren increased the number of hours its Rush Island units were able to run, or if the company enabled the units to operate at higher output levels during those hours, then the units would . . . burn[] more coal and, as a result, emit[] more pollution." *Id.* at 994–95. Dr. Hausman's "results show[ed] that Ameren's modeling would predict significant emissions increases at the Rush Island units as a result of the projects." *Id.* at 996.

Finally, "the actual post-project data" showed "a significant net [sulfur dioxide] increase of more than 40 tons that was caused by the projects." *Id.* at 998. Both units were available more and operated every hour that they were available. Both units also increased their maximum generating levels. This resulted in both units increasing their sulfur dioxide pollution.

In summary, the court determined that "[b]ased on the known facts that the Rush Island units are low-cost, baseload units, common sense compels the same conclusion: improving availability or capacity at baseload units like Rush Island will result in additional operations and pollution." *Id.*

Regarding liability, the district court also rejected Ameren's defenses. First, the district court concluded that Ameren failed to satisfy "its burden of proving that the Rush Island projects fall within the narrow routine maintenance exemption." *Id.* at 1003. The court characterized "[t]he 2007 and 2010 major boiler outages [as] unprecedented events for Rush Island Units 1 and 2—they were the centerpieces of the 'most significant' outages in plant history." *Id.* (citation omitted).

Second, the court rejected Ameren's argument that any increases in production and pollution were merely the result of demand growth that should be excluded from the liability assessment. According to the court, the "relevant information" that Ameren had "showed that the Rush Island units' performance would improve, resulting in increased generation and emissions." *Id*. at 1010.

In summary, the district court "enter[ed] a finding of liability against Ameren," concluding that the Rush Island Unit 1 and 2 projects described above were major modifications under the CAA, Ameren violated the PSD program's requirements "by failing to obtain a preconstruction permit and install best available pollution control technology," and Ameren violated Title V of the CAA. *Id.* at 1017.

2. *Remedy Phase*

a. *Summary Judgment*

After entering its post-trial order on liability, the district court proceeded to the remedy phase. The court addressed the parties' summary-judgment motions. First, the court rejected Ameren's argument "that the Clean Air Act does not authorize injunctions as a remedy for past violations." *United States v. Ameren Mo. (Ameren IV)*, 372 F. Supp. 3d 868, 871 (E.D. Mo. 2019). According to the court, "[t]he plain language of § 7413(b) gives the EPA authority to 'commence a civil action' for injunctive relief or civil penalties, 'or both,' whenever a person '*has* violated or is in violation of any requirement or prohibition of' EPA air quality control programs." *Id.* (quoting 42 U.S.C. § 7413(b)). The court reasoned that § 7413(b)'s plain "language places no restriction on injunctive relief for past violations" and instead "authorizes the EPA to seek injunctive relief whenever a person *has violated* the Clean Air Act." *Id.*

In addition, the district court rejected Ameren's argument that the court could not "order injunctive relief that includes emissions reductions or control technology at the Labadie Energy Center (Labadie) coal-fired power plant." *Id.* at 874.

b. *Trial*

The district court subsequently held a remedy trial. Following the trial, the court issued an order imposing a two-pronged remedy with the purpose of "[(1)] bring[ing] Ameren's Rush Island facility into compliance with the law and [(2)] . . . remediat[ing] the harm from the more than 162,000 tons—and counting—in excess [sulfur dioxide] that Rush Island emitted after Ameren failed to obtain a PSD permit there." *United States v. Ameren Mo. (Ameren V)*, 421 F. Supp. 3d 729, 802 (E.D. Mo. 2019).

As to compliance, the district court concluded that "Ameren must make Rush Island compliant by obtaining a PSD permit with emissions limitations based on wet FGD [flue gas desulfurization technology]" used as the BACT. *Id.* at 806 (emphasis omitted). The court determined that FGD technology is technically and economically feasible and "can remove 95% or more of [sulfur dioxide] emissions." *Id.* at 812.

As to remediation, the district court concluded that "Rush Island's excess pollution is best remediated by decreasing emissions at the nearby Labadie Energy Center." *Id.* at 789 (emphasis omitted). Labadie consists of four coal-burning units and is located 35 miles west of St. Louis. Ameren argued that imposition of the remedy was "extreme" and "constitute[d] a penalty" "because Labadie is 'totally innocent,' and Ameren has not violated the Clean Air Act there." *Id.* at 820. The district court rejected Ameren's argument, reasoning that its "remedy is based on straightforward equitable principles and the authority [it] ha[s] under the Clean Air Act 'to restrain' violations, 'to require compliance,' and 'to award any other appropriate relief.'" *Id.* (quoting 42 U.S.C. § 7413(b)). According to the court, its remedy was "narrowly tailored" because "a tight geographic nexus [exists] between the harms Rush Island caused and the benefits gained through reducing Labadie's emissions. Pollution from Labadie affects the same communities as those affected by Rush Island, and to the same degree." *Id.* at 820–21. The court reasoned that its remedy "achieve[d] the maximum possible environmental benefit": "When Ameren reduces emissions at Labadie commensurate with the excess emissions from Rush Island, Ameren will have put the public in the place it would have been absent Ameren's Clear Air Act violation." *Id.* at 821. The court explained that "Ameren's ton-for-ton reductions at Labadie will lower the risks of premature mortality and disease in the same communities impacted by Ameren's Rush Island violations." *Id.*

The court rejected Ameren's argument "that any injunction against its Labadie plant would constitute a penalty." *Id*. While the court acknowledged it could not "issue injunctive relief that would constitute a penalty," it concluded that "[b]y ordering emissions reductions up to, but not surpassing, the excess emissions from Rush Island, [the court was] ordering relief that goes exactly to 'remedying the damage caused to the harmed parties by the defendant's action.'" *Id.* (quoting *United States v. Ameren Mo.*, No. 4:11-cv-77-RWS, 2016 WL 468557, at *1 (E.D. Mo. Feb. 8, 2016)). The court "order[ed] Ameren to base its relief at Labadie on DSI [dry sorbent injection] control technology" "[t]o . . . ensure that any relief at Labadie does not surpass the damage caused by Rush Island." *Id.* Installation of DSI technology on Labadie's units would allow Ameren to "operate DSI for as many years as necessary to remediate Rush Island's excess emissions[] and terminate its use of DSI without suffering significant lost capital assets." *Id.* The court "order[ed] Ameren to begin operating Labadie with DSI, or a more effective pollution control, beginning no later than three years after [its] order." *Id.* at 822.

3. *Summary*

In summary, the district court found Ameren in violation of the CAA for "mak[ing] major modifications to expand Rush Island's capacity" without "apply[ing] for a PSD permit and meet[ing] reduced emissions requirements." *Id.* at 824. By failing to "apply for the required PSD permit," Ameren "skirted PSD's requirement to install the best available technology to control the pollution Rush Island emits." *Id.*

"To remedy [Ameren's] violation of the Clean Air Act," the district court ordered Ameren to "apply for a PSD permit for Rush Island within ninety days, propose wet FGD as BACT in its permit application, and implement BACT no later than four and one-half years from [the] order." *Id.* "In addition to the relief [the court] order[ed] at Rush Island, [it] also order[ed] Ameren to reduce its pollution at Labadie in an amount equal to Ameren's excess emissions at Rush Island." *Id.* It left Ameren the option whether to "install[] DSI or some other more effective pollution control at Labadie." *Id.*

II. *Discussion*

Ameren appeals the district court's orders. It raises five arguments: (1) the Rush Island projects did not require permits under the Missouri SIP; (2) the Rush Island projects did not constitute major modifications; (3) the district court lacked jurisdiction under Article III and statutory authority under the CAA to enter the injunctions; (4) the injunctive relief ordered at Labadie is punitive, not remedial, and therefore prohibited; and (5) the district court lacked jurisdiction over the Title V claims. We address each in turn.

A. *Missouri SIP*

Ameren first argues that "under the plain language of Missouri's SIP, permits are required only for increases in potential emissions" and "it [is] undisputed that the [Rush Island] Projects would not, and did not, increase potential emissions." Appellant's Br. at 30. According to Ameren, the district court erroneously "substituted the federal regulations' applicability standard," which "nullified the SIP Permit Rule's Applicability Provision." *Id.* at 30–31.

The Missouri SIP identifies which construction or modification projects at emission sources require prior construction permits. Mo. Code Regs. Ann. tit. 10, § 6.060 (2007). Ameren cites to § 6.060(1) of the Missouri SIP, entitled "Applicability" ("Applicability Section"). This section governs Missouri's air quality construction permit programs. The Applicability Section provides, in relevant part, that

> [n]o owner or operator shall commence construction[[2]] or *modification* of any installation subject to this rule, begin operation after that construction or *modification*, or begin operation of any installation which has been shut down longer than five (5) years without first obtaining a permit from the permitting authority under this rule.

Mo. Code Regs. Ann. tit. 10, § 6.060(1)(C) (2007) (emphases added).

In turn, the Missouri SIP offers two definitions of *modification*. First, it generally defines "[m]odification" as "[a]ny physical change, or change in method of operation of, a source operation or attendant air pollution control equipment which would cause an increase in *potential emissions* of any air pollutant emitted by the source operation." *Id.* § 6.020(2)(M)(10) (emphasis added). "Potential to emit" means

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[2]"It is undisputed that the projects at issue were not 'construction' as defined by the Missouri SIP or the PSD rules." *Ameren I*, 158 F. Supp. 3d at 809 n.5.

the unit's ability to emit at full design capacity "assuming continuous year-round operation." *Id.* at § 6.020(2)(P)(19).

Second, the Missouri SIP separately defines "Title I modification." *Id.* § 6.020(2)(M)(11). A "Title I modification" is "[a]ny modification that requires a permit under *10 CSR 10-6.060 section (7) or (8)*, or that is subject to any requirement under 10 CSR 10-6.070 or 10 CSR 10-6.080." *Id.* § 6.020(2)(T)(3) (emphasis added).[3]

Ameren maintains that the Missouri SIP limits PSD applicability to only projects increasing both actual *and* potential emissions. According to Ameren, the Missouri SIP's Applicability Section and definitional sections mean that "[i]f a project would *not* increase a unit's potential emissions, it is *not* a modification and does *not* trigger permitting under the Applicability Provision." Appellant's Br. at 35. Because the government "never alleged that the projects increased the units' potential emissions, Ameren argues that it [was] entitled to full summary judgment." *Ameren I*, 158 F. Supp. 3d at 808–09.

Ameren, however, overlooks that, in contrast to the general definition of *modification* in § 6.020(2)(M)(10), § 6.060(8)(A) of the Missouri SIP contains "*PSD-specific* applicability language." *Id.* at 809 (emphasis added) (citing *RadLAX Gateway Hotel, LLC v. Amalgamated Bank*, 566 U.S. 639, 645 (2012)). That section—expressly referenced in the Missouri SIP's definition of "Title I modification"—provides, in relevant part:

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[3]In addition to defining *modification*, the Missouri SIP independently defines "[m]ajor modification" as "[a]ny physical change or change in the method of operation at an installation or in the attendant air pollution control equipment that would result in a significant net emissions increase of any pollutant." *Id.* § 6.020(2)(M)(3). The Missouri SIP uses the term *major modification* in a section concerning BACT. *See id.* § 6.020(2)(B)(5).

(8) Attainment and Unclassified Area Permits.

(A) *All of the subsections of 40 CFR 52.21* other than (a) Plan disapproval, (q) Public participation, (s) Environmental impact statements and (u) Delegation of authority *are incorporated by reference*. 40 CFR 52.21 as used in this rule refers to 40 CFR 52.21 promulgated as of July 1, 2003 as published by the Office of the Federal Register, U.S. National Archives and Records, 700 Pennsylvania Avenue NW, Washington, D.C. 20408. This rule does not incorporate any subsequent amendments or additions.

Mo. Code Regs. Ann. tit. 10, § 6.060(8)(A) (2007) (emphases added).

In turn, the federal regulation referenced in § 6.060(8)(A) of the Missouri SIP provides that the PSD's "[a]pplicability procedures" "apply to the construction of any new major stationary source or the *major modification of* any existing major stationary source" located in a PSD area. 40 C.F.R. § 52.21(a)(2)(ii) (emphasis added). The regulations explicitly define major modification. "*Major modification* means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase . . . of a regulated NSR pollutant . . . ; and a significant net emissions increase of that pollutant from the major stationary source." *Id.* § 52.21(b)(2)(i) (emphasis added). "A . . . major modification shall meet each applicable emissions limitation under the [SIP] and each applicable emissions standard and standard of performance under 40 CFR parts 60 and 61." *Id.* § 52.21(j)(1).

The federal regulation establishes that a *major modification* triggers the PSD requirements. According to the regulation, "[n]o . . . major modification . . . shall begin actual construction without a permit that states that the . . . major modification will meet those requirements." *Id.* § 52.21(a)(2)(iii). To assess whether a major modification occurred, the federal regulation states that an "*[a]ctual-to-projected-actual applicability test* [applies] for projects that only involve existing emissions units." *Id.* § 52.21(a)(2)(iv)(c) (emphasis added). Under that test,

> [a] significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions . . . and the baseline actual emissions . . . , for each existing emissions unit, equals or exceeds the significant amount for that pollutant . . . .

Id.

As the district court observed, "EPA's approval of the [Missouri] SIP illustrates why the specific PSD rules control." *Ameren I*, 158 F. Supp. 3d at 810. In approving the Missouri SIP, the EPA stated, "[W]e are approving most of the revisions to the Construction Permits Required rule because the revisions incorporate, by reference, the Federal New Source Review reforms . . . . " Approval and Promulgation of Implementation Plans; State of Missouri, 71 Fed. Reg. at 36,486. More specifically, it stated that it was "approving revisions to Missouri rule, 10 CSR 10-6.060, Construction Permits Required, into the SIP. This rule incorporates by reference the . . . PSD . . . program in 40 CFR 52.21 . . . ." *Id.* at 36,487.

Importantly, the "EPA's approval of the SIP provided that the CAA and the program requirements as set out in 40 C.F.R. 52.21 would supersede any conflicting provisions in the state SIP." *Ameren I*, 158 F. Supp. 3d at 810 (quoting 71 Fed. Reg. at 36,486 ("This revision incorporates by reference the other provisions of 40 C.F.R. 52.21 as in effect on July 1, 2003, *which supersedes any conflicting provisions in the Missouri rule.*" (emphasis added in *Ameren I*))).

Furthermore, as the district court pointed out, Ameren's argument that "the [Missouri] SIP first requires . . . that a threshold determination be made that a project is a 'modification'" under § 6.020(2)(M)(1), "would render a portion of the PSD rules superfluous." *Id.* at 810. The Supreme Court rejected a similar argument in *Duke Energy*. In that case, the Court held that the EPA is not required "to conform its PSD regulations on 'modification' to their NSPS counterparts." 549 U.S. at 565. According to the Court, aligning the PSD regulations with the NSPS regulations "was inconsistent with their terms and effectively invalidated them." *Id.* Relevant to the present case, the Court rejected the defendant power company's argument that, "before a project can become a 'major modification' under the PSD regulations, it must meet the definition of 'modification' under the NSPS regulations." *Id*. at 581 n.8 (citations omitted). According to the Court, "the language of the regulations [did] not support" such a reading because it would render portions of the PSD regulations superfluous. *Id.* ("[I]t would be superfluous for PSD regulations to require a 'major modification' to be a 'physical change in or change in the method of operation,' if they presupposed that the NSPS definition of 'modification,' which contains the same prerequisite, had already been satisfied." (citations omitted)).

Finally, *United States v. Cinergy Corp.*, 623 F.3d 455 (7th Cir. 2010), upon which Ameren relies, is distinguishable. There, the EPA brought an enforcement action against several coal-fired power plants. *Id.* at 456. As in the present case, the EPA alleged that the plants' projects were major modifications requiring a PSD permit. *Id.* The plants argued that no permit was required because the projects did not increase the units' potential emissions under the Indiana SIP, which based applicability on increases in potential emissions instead of actual emissions. *Id.* at 458. On appeal, the Seventh Circuit held that "[t]he Clean Air Act does not authorize the imposition of sanctions for conduct that complies with a [SIP] that the EPA has approved." *Id.* (citing 42 U.S.C. § 7413(a)(1)).

Like the power plants in *Cinergy*, Ameren maintains that it lacked notice "that EPA would treat its approval of Sections 10–6.060(1)(C) (Applicability) and 10–6.020(2)(M)(10) (definition of 'modification') as a rejection of them"; furthermore, it asserts that "allowing EPA to impose liability when it is undisputed no modification has occurred would violate basic principles of due process and fair notice." *Ameren I*, 158 F. Supp. 3d at 812. But *Cinergy* is distinguishable from the present case because (1) the Indiana SIP did not incorporate the PSD rules into the State's plan; (2) the "EPA's approval of the Indiana SIP did not expressly provide that the PSD rules as set out in the Code of Federal Regulations supersede any conflicting provisions in the state SIP"; and (3) the power plants in *Cinergy* had "actual notice" of the Indiana SIP provision, whereas "it is not clear that Ameren had actual notice of the SIP provision." *Id.* Furthermore, *Cinergy* is merely persuasive authority and not binding on this court. *See Duluth, Winnipeg & Pac. Ry. Co. v. City of Orr*, 529 F.3d 794, 798 (8th Cir. 2008).

Accordingly, we hold that the district court did not err in holding that the Rush Island projects required permits through application of the actual-to-projected-actual applicability test under 40 C.F.R. § 52.21(a)(2)(iv)(c), incorporated by reference in § 6.060(8)(A) of the Missouri SIP.

B. *Major Modification*

Alternatively, Ameren argues that "even if federal regulations governed applicability, Ameren was held liable under the wrong legal standards, independently requiring reversal." Appellant's Br. at 45. Ameren maintains that the district court erred in concluding the Rush Island projects constituted *major modifications*. Specifically, Ameren contends that the district court erroneously (1) shifted the burden of proof on causation; (2) "applied new interpretations of the federal regulations' causation provision"; and (3) applied a "'reasonable power plant operator' standard the regulations do not require." *Id.* at 45–46. In addition, Ameren asserts that the district court erred by permitting the government to use expert opinions on actual post-project emissions that were not disclosed. *Id.* at 56.

A "[m]ajor modification" at emission sources occurs when a physical change in the facility would result in "a significant emissions increase." 40 C.F.R.

§ 52.21(b)(2)(i). "To satisfy its burden under the [CAA], the government ha[s] to show that at the time of the projects [Ameren] expected, or should have expected, that its modifications would result in a 'significant net emissions increase' . . . ." *United States v. Ala. Power Co.*, 730 F.3d 1278, 1282 (11th Cir. 2013).

1. *Burden of Proof*

One feature of the federal regulation's "projected-actual-emissions methodology [is] the exclusion from the emissions projection of any emissions due to increased demand." *New York*, 413 F.3d at 31. This demand-growth exclusion functions as a type of defense for the source to avoid triggering PSD requirements. The federal regulation "allow[s] exclusion of emissions that could have been accommodated during the baseline period and 'that are also unrelated to the particular project.'" *Id.* at 33 (quoting 40 C.F.R. § 52.21(b)(41)(ii)(c)). Emissions "unrelated to the particular project . . . include[] any increased utilization due to product demand growth." *Id.* (quoting 40 C.F.R. § 52.21(b)(41)(ii)(c)).

Thus, under the regulation, "a source must"

> establish[] two criteria . . . before excluding emissions from its projection: "(1) [t]he unit could have achieved the necessary level of utilization during the consecutive 24-month period [the source] selected to establish the baseline actual emissions; and (2) the increase is not related to the physical or operational change(s) made to the unit."

Id. (alterations in original) (emphasis added) (quoting Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Baseline Emissions Determination, Actual-to-Future-Actual Methodology, Plantwide Applicability Limitations, Clean Units, Pollution Control Projects, 67 Fed. Reg. 80,186-01, 80,203 (Dec. 31, 2002)); *see also United States v. DTE Energy Co.*, 845 F.3d 735, 737 (6th Cir. 2017).

Ameren argues that "the [d]istrict [c]ourt improperly shifted the burden of proving causation to Ameren." Appellant's Br. at 46. Before the district court, the parties disputed who bore the burden of proving "that any increases in emissions were caused by demand growth." *Ameren II*, 2016 WL 728234, at *11. Ameren argued that the EPA bore the burden of proving demand growth "because under the definition of 'projected actual emissions,' the regulations require that unrelated emissions be exempted from the calculation." *Id.* By contrast, the EPA maintained that Ameren bore the burden of proof on demand growth as "the party seeking to benefit from an exemption." *Id.* The district court held that "*while it remains EPA's burden to prove that Ameren should have expected the projects to cause an increase in emissions*, the burden is Ameren's to prove that the demand growth exclusion applies." *Id.* (emphasis added).

The district court is correct. As recognized in *New York* and *DTE Energy*, it is the source's burden to prove the applicability of the demand-growth exclusion. This is in accordance with the Supreme Court precedent that the party asserting the exception bears the burden of proving its applicability. *NLRB v. Ky. River Cmty. Care, Inc.*, 532 U.S. 706, 711 (2001) ("The burden of proving the applicability of the supervisory exception . . . should thus fall on the party asserting it."); *FTC v. Morton Salt Co.*, 334 U.S. 37, 44–45 (1948) ("[T]he general rule of statutory construction that the burden of proving justification or exemption under a special exception to the prohibitions of a statute generally rests on one who claims its benefits . . . .").

As a result, we hold that the district court did not impermissibly shift the burden of proof to Ameren in proving the applicability of the demand-growth exclusion.

2. *Causation*

According to Ameren, in post-trial briefing, the government switched theories on how the district court should analyze increased demand to satisfy the demand-growth exclusion. Ameren also asserts that the government, in effect, promulgated a new causation standard without following notice-and-comment rulemaking. Specifically, Ameren contends, the government persuaded the district court that Ameren had to show "demand growth for a specific unit's generation." Appellant's Br. at 47. Ameren argues that this causation standard is "the exact opposite of EPA's prior statements [that] '[d]emand growth refers to what the utility expects to be required to produce in the way of energy system wide, *not for a single unit*, but system wide.'" *Id.* (citation omitted).

We hold that the district court did not apply an improper causation standard. Citing *New York*, the district court expressly acknowledged that Ameren had to satisfy "two criteria . . . before excluding emissions from its projection." *Ameren III*, 229 F. Supp. 3d at 1003 (quoting *New York*, 413 F.3d at 33). The first requirement is that "*the unit* could have achieved the necessary level of utilization during the [baseline period]." *Id.* (emphasis added) (alteration in original) (quoting *New York*, 413 F.3d at 33). The second requirement is that "the increase is not related to the physical or operational change(s) made to *the unit*." *Id.* (emphasis added) (quoting *New York*, 413 F.3d at 33). This accurately states the appropriate causation standard. As a result, the district court did not err in holding that to prove the applicability of the demand-growth exclusion, Ameren had to establish "that demand *on the unit* increases." *Id.* at 1003.

3. *Reasonable Power Plant Operator*

"In order to be deemed a major modification, [the government] . . . [must] show (1) a physical change to the plant; (2) a significant net emissions increase; and (3) a causal link between the two." *United States v. La. Generating, LLC*, 929 F. Supp. 2d 591, 593 (M.D. La. 2012). As explained *supra*, "the government had to show that at the time of the projects [Ameren] expected, or should have expected, that its modifications would result in a 'significant net emissions increase' . . . ." *Ala. Power Co.*, 730 F.3d at 1282.[4]

"[T]he [federal] regulations do not require a utility to be prescient, rather they require the company to undertake a *reasonable estimate* of what post-project emissions would be." *United States v. Duke Energy Corp.*, No. 1:00-cv-1262, 2010 WL 3023517, at *6 (M.D.N.C. July 28, 2010) (emphasis added) (citing *United States v. Cinergy Corp.*, 458 F.3d 705, 709 (7th Cir. 2006)). "[T]he question [is] whether the owner of the facility at the time of the work . . . expected or *reasonably should have expected*, the work to increase emissions . . . ." *La. Generating*, 929 F. Supp. 2d at 593 (emphasis added).

In its motion for summary judgment at the liability phase, Ameren argued that "under an expectations theory," the EPA had to "come forward with admissible evidence of what a reasonable power plant operator or owner would expect, and its failure to do so is fatal to EPA's expectations theory case, warranting a grant of partial summary judgment." *Ameren II*, 2016 WL 728234, at *18. While "Ameren acknowledge[d] that the determination of whether a party acted reasonably is generally a question for the factfinder," it maintained that "when the touchstone for objective reasonableness requires a technical understanding of the subject matter that is beyond a layperson's normal understanding, the factfinder must have guidance to make that determination." *Id.*

The district court, however, determined "that no special standard of care evidence is required for the factfinder to be able to determine whether a reasonable power plant operator or owner would have expected the projects to cause a significant emissions increase." *Id.* The court reasoned that (1) "[t]he legal standards supplied

[4]Alternatively, the government can prove a project actually resulted in a significant increase in emissions. *See* 40 C.F.R. § 52.21(a)(2)(iv)(b).

by the PSD rules are sufficient to guide the analysis," and (2) "the parties . . . submitted mountains of evidence regarding what they believe a reasonable power plant operator or owner would have concluded." *Id.* Specifically, the parties' experts would "testify about what Ameren did to make its projections, what information Ameren considered or did not consider, and why, and what the projections showed." *Id.* The court noted that other "courts that have considered expectations theory enforcement actions" have applied "[t]his method." *Id.* (first citing *United States v. Duke Energy Corp.*, 981 F. Supp. 2d 435, 439 (M.D.N.C. 2013); then citing *Cinergy*, 623 F.3d at 459; and then citing *La. Generating*, 929 F. Supp. 2d at 593).

On appeal, Ameren now asserts that the district court erroneously denied "[s]tandard-of-care evidence [in] defining the specific boundaries of reasonableness." Appellant's Br. at 50. According to Ameren, "the written requirements of the regulations," as opposed to the "expert witnesses' subjective views," "should have governed liability." *Id.* Ameren maintains that "[b]y superimposing a[] [reasonable power plant operator] standard, the [d]istrict [c]ourt allowed EPA's experts to second-guess Ameren's conclusions even though Ameren followed the regulations' written requirements." *Id.* at 51.

We conclude that the district court did not err in holding that "no special standard of care evidence is required for the factfinder to be able to determine whether a reasonable power plant operator or owner would have expected the projects to cause a significant emissions increase." *Ameren II*, 2016 WL 728234, at *18. Instead, the district court, as the factfinder, was entitled to "consider all relevant information available to [Ameren] at the time of the project, including prior operating data and [Ameren's] own statements and documents" in determining whether Ameren "should have predicted that a project would have caused a [significant] net increase." *Id.* at *19 (quoting Jury Instr. No. 23, *United States v. Cinergy*, 1:99-cv-1693-LJM-JMS (S.D. Ind. 2008), ECF No. 1335).

4. *Expert Testimony*

Ameren argues that the district court abused its discretion in admitting and relying on undisclosed expert opinions. *See Ryan v. Bd. of Police Comm'rs of St. Louis*, 96 F.3d 1076, 1081 (8th Cir. 1996) ("We review the district court's decision to admit evidence over a party's objection for abuse of discretion.").

In two motions filed during the trial on the liability phase and in post-trial briefs, Ameren moved to exclude the expert testimony of Koppe and Dr. Sahu "concerning causation of the actual emissions increases." *Ameren III*, 229 F. Supp. 3d at 1015. Ameren argued to the district court that "the testimony concerning the causation of the actual emissions increases are new, undisclosed opinions." *Id.*

The district court denied Ameren's motions to exclude Koppe's and Dr. Sahu's testimony. First, it rejected Ameren's argument that the experts' opinions were "new" and concluded that Ameren had "sufficient notice of both the United States' actual emissions case and of Mr. Koppe and Dr. Sahu's opinions." *Id*. at 1016. The court highlighted that the experts "(1) analyzed the actual post-project data in their reports, the attachments, and their work papers, and (2) stated that the projected increases actually materialized." *Id.* at 1015. Additionally, the court noted that the experts discussed in their reports and depositions "how the projects enable increased availability and contribute to increases in emissions." *Id.* The court explained that the experts were not required to "state[] their opinions in the precise words that Ameren thinks they should have used" because the "notice required of expert opinions is not so formulaic." *Id.*; *see also Thompson v. Doane Pet Care Co.*, 470 F.3d 1201, 1202–03 (6th Cir. 2006) (explaining that Federal Rule of Evidence 26(a)(2)(B) "contemplates that the expert will supplement, elaborate upon, explain and subject himself to cross-examination upon his report")).

Second, the district court concluded that even if it erroneously admitted the expert testimony, Ameren was unable to "show that it was prejudiced by the challenged testimony or the admission of the exhibits." *Ameren III*, 229 F. Supp. 3d at 1016. This was because "[t]he evidence the United States presented to show that the actual emissions increases were caused by the projects was also presented in the context of its expectations case regarding the expected causes of projected emissions increases, so the challenged testimony is in part cumulative evidence." *Id.* The court also noted Ameren's "opportunity both during pre-trial discovery and during cross-examination at trial to test those opinions." *Id.*

Here, even assuming that the district court abused its discretion by admitting the expert testimony, "any error would be harmless." *Smith v. Tenet Healthsystem SL, Inc.*, 436 F.3d 879, 889 (8th Cir. 2006). Harmless error applies here because the district court, as the factfinder, expressly stated that had the expert testimony on actual emissions not been admitted, the result would not be different.

C. *Injunctive Relief*

Ameren argues generally that the district court lacked Article III jurisdiction and statutory jurisdiction to issue injunctive relief "based on Rush Island's *operation*." Appellant's Br. at 66. According to Ameren, the district court found during the liability phase "that the Rush Island Projects were major modifications requiring permits before Ameren could commence construction." *Id.* at 67. But, during the remedy phase, the government "did not seek to prove any injury from the violation it proved" and "[i]nstead . . . sought to obtain relief based on the harm from Rush Island's operation without a PSD permit." *Id.* Ameren maintains that "[o]perations do not cause an injury that the PSD program recognizes." *Id.* Ameren further argues that the district court lacked jurisdiction to impose injunctive relief redressing "excess emissions." *Id.* at 69. Ameren asserts that the government waived "penal relief, including civil penalties; an injunction to prevent construction; an injunction to obtain information about future planned projects; and declaratory relief." *Id.* at 71 (citations omitted). Finally, Ameren argues that the CAA "does not authorize injunctions for wholly past violations" and that "[o]nly past violations are at issue here." *Id.* at 72.

"We review a district court's grant of a permanent injunction for abuse of discretion." *Kittle-Aikeley v. Strong*, 844 F.3d 727, 735 (8th Cir. 2016). An abuse of discretion occurs when a district court "reaches its conclusion by applying erroneous legal principles or relying on clearly erroneous factual findings." *Id.* (citation omitted). "Where the determinative question is purely legal, our review is more accurately characterized as *de novo*." *Id.* (quotation omitted).

"Whenever . . . the [government] finds that any person *has violated* or is in violation of any requirement . . . of an applicable implementation plan or permit, [the government] [must] notify the person . . . of such finding." 42 U.S.C. § 7413(a)(1) (emphasis added). Only after the "expiration of 30 days following the date on which such notice of a violation [was] issued" may the government "bring a civil [enforcement] action." *Id.* § 7413(a)(1)(C). The government is authorized to "commence a civil action for a permanent or temporary injunction, or to assess and recover a civil penalty . . . , or both," "[w]henever such person *has violated*, or is in violation of" a requirement of Title I of the CAA. *Id.* § 7413(b)(1) (emphasis added). A civil enforcement action

> may be brought in the district court of the United States for the district in which the *violation* is alleged to have occurred, or is occurring, or in which the defendant resides, or where the defendant's principal place of business is located, and such *court shall have jurisdiction to restrain such violation, to require compliance, to assess such civil penalty, to collect any fees owed* the United States under this chapter (other than subchapter II) *and any noncompliance assessment and nonpayment penalty owed* under section 7420 of this title, *and to award any other appropriate relief*.

Id. § 7413(b) (emphases added).

In summary,

> [t]he Clean Air Act authorizes the EPA to bring a civil enforcement action when any person *has violated* a permit or SIP, *has violated* any requirement in certain subchapters of the Clean Air Act (including the PSD program), or "attempts to construct or modify a major stationary source" in any state that the EPA Administrator has found out of compliance with the New Source Review program.

United States v. EME Homer City Generation, L.P., 727 F.3d 274, 291–92 (3d Cir. 2013) (emphases added).

Section 7413(b) "limits a district court's jurisdiction to awarding certain kinds of relief." *Id.* at 292. "Each type of relief in [§ 7413(b)] (except for civil penalties) is necessarily forward-looking." *Id.* (footnote omitted). The remaining term —"[a]ny other appropriate relief"—is merely a "catch-all" provision that "follows 'a list of specific items separated by commas.'" *Id.* at 293 (quoting *Ali v. Fed. Bureau of Prisons*, 552 U.S. 214, 225 (2008)). "As the word 'other' demonstrates, this general phrase is a residual category of the same type as the preceding items (namely, kinds of relief)." *Id.* "[T]he canon of *ejusdem generis* requires us to interpret this catch-all as permitting forward-looking relief, consistent with the preceding types of relief in the list." *Id.* at 295.

In *Homer City*, the Third Circuit held that "[t]he text of the Clean Air Act does not authorize an injunction against *former* owners and operators for a *wholly past PSD violation*, even if that violation causes *ongoing harm*." *Id.* at 291 (emphases added). But the court "express[ed] no opinion" on whether injunctions are "available in general to remedy *ongoing harm* from *wholly past violations*." *Id.* at 291 n.19 (emphases added). Indeed, as against the current owners, the court explained that the government could, after "*completion* of a facility's modification, . . . still obtain an *injunction* requiring the owner or operator to comply with the PSD requirements." *Id.*

at 289 (emphases added); *see also United States v. U.S. Steel Corp.*, 16 F. Supp. 3d 944, 950 (N.D. Ind. 2014) ("Requiring a company to do 'a further round of modifications to get the permit' could only be done through injunctive relief." (quoting *United States v. Midwest Generation, LLC*, 720 F.3d 644, 646 (7th Cir. 2013)).

Homer City is distinguishable from the present case because it concerned injunctive relief against a facility's *former* owners. *United States v. Luminant Generation Co., L.L.C.*, 905 F.3d 874, 888 (5th Cir. 2018), *reh'g en banc granted*, 929 F.3d 316 (5th Cir. 2019).[5] It does not detract from the plain language of § 7413(b), which "plainly gives district courts jurisdiction to restrain a violation, require compliance, and award any other appropriate relief whenever a person has committed a . . . violation" *Id.*

Here, however, Ameren also specifically challenges the district court's injunction against its Labadie plant, which committed no violations of the CAA. According to Ameren, neither the CAA nor the regulations authorize such relief.

Under § 7413, a district court "has the authority to order [a defendant] to take appropriate actions that remedy, mitigate and offset harms to the public and the environment *caused by the [defendant's] proven violations* of the CAA." *United States v. Cinergy Corp.*, 582 F. Supp. 2d 1055, 1060 (S.D. Ind. 2008) (emphasis added); *see also United States v. Oliver*, No. 3:06-CV-196-JWS, 2009 WL 10671371, at *13 (D. Alaska June 25, 2009) ("Section 113(b) of the Clean Air Act, 42 U.S.C. § 7413(b), expressly provides for injunctive relief to *redress violations* of the Act." (emphasis added)), *aff'd*, 394 F. App'x 376 (9th Cir. 2010).

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[5]The Fifth Circuit ultimately dismissed the appeal in *Luminant* on the parties' motion.

Here, the government never provided notice of or alleged that the Ameren's Labadie plant committed a *violation* of the CAA. The plain language of § 7413(b) and caselaw make clear that the injunctive relief a district court may award must redress a *violation* of the CAA. *See* 42 U.S.C. § 7413(b)(1)–(3) (permitting civil enforcement actions "[w]henever such person has violated, or is in violation of" certain requirements and noting that the district "court shall have jurisdiction to restrain such violation"). Because Ameren committed no violation of the CAA at its Labadie plant, the district court lacked authority to authorize injunctive relief as to it. *Cf. United States v. Cinergy Corp.*, 618 F. Supp. 2d 942, 967 (S.D. Ind. 2009) (denying government's requested relief because the remedy would be punitive as the government proved no violation at the non-source unit against which it was sought.), *rev'd on other grounds*, 623 F.3d 455 (7th Cir. 2010); *United States v. Westvaco Corp.*, No. MJG-00-2602, 2015 WL 10323214, at *12 & n.27 (D. Md. Feb. 26, 2015) (rejecting government's request for the district court to order the defendant "to install control technology on a totally 'innocent' boiler" that the government never alleged "violated PSD regulations" (footnote omitted)).

Accordingly, we reverse the Labadie injunction and remand for further proceedings consistent with this opinion.

E. *Jurisdiction over Title V Claims*

Finally, Ameren challenges the district court's jurisdiction over the Title V claims.

Ameren operates Rush Island under a Title V permit issued by the Missouri Department of Natural Resources. This permit "restat[ed] the requirement that Ameren was prohibited from performing any unpermitted major modifications of Rush Island Units 1 or 2." *Ameren III*, 229 F. Supp. 3d at 985.

The government brought Title V claims against Ameren, and Ameren challenged the district court's subject matter jurisdiction to hear those claims. It argued—as it does here—that the Title V violation "is reviewable exclusively by the courts of appeals, not collaterally in civil . . . enforcement actions in the district courts." Appellant's Br. at 73 (alteration in original) (quoting *Homer City*, 727 F.3d at 296–97).

Ameren's jurisdictional argument lacks merit. "The EPA has authority to bring a civil enforcement action against a person who, among other things, 'has violated, or is in violation of, any other requirement or prohibition of [various subchapters, including Title V].'" *Homer City*, 727 F.3d at 298 (alteration in original) (quoting 42 U.S.C. § 7413(b)(2)). In turn, Title V's plain text "lists only two ways in which it can be violated: operating without a Title V permit or *violating the terms of a Title V permit while operating a source*." *Id.* (emphasis added) (citing 42 U.S.C.§ 7661a(a)).

The district court expressly found that Ameren violated an express permit term prohibiting it from performing unpermitted major modifications. *Cf. Otter Tail*, 615 F.3d at 1020. Under § 7413(b), the district court had jurisdiction to consider whether Ameren violated the express terms of its Title V permit.

III. *Conclusion*

Accordingly, we affirm the judgment of the district court in all respects *except* as to the injunctive relief entered against Ameren's Labadie plant. We remand for further proceedings consistent with this opinion.

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