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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EF-2024-0021

DIRECT TESTIMONY

OF

STEVEN C. WHITWORTH

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
November 21, 2023

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DIRECT TESTIMONY

OF

STEVEN C. WHITWORTH

FILE NO. EF-2024-0021

I. INTRODUCTION

Q. Please state your name and address.

A. Steven Whitworth, 20 Pine Valley Drive, Collinsville, Illinois.

Q. Are you currently employed?

A. No. I retired in 2022, after almost 42 years with Ameren Missouri, Ameren Services Company ("Ameren Services"), and their predecessor entities.

Q. Please describe your educational background and employment experience.

A. I graduated from Illinois State University in 1980 with a B.S. in Biological Sciences, with a minor in Chemistry. I then began working at Central Illinois Public Service ("CIPS") in 1980, working at the Hutsonville coal-fired power plant. At Hutsonville, I had various roles: laboratory technician, engineering technician, relief supervisor, and finally staff engineer. During my time at Hutsonville, I obtained an associate's degree in mechanical engineering technology. I became very familiar with the operation and maintenance of coal-fired units during my tenure at Hutsonville (1980-1989). As staff engineer at Hutsonville, I worked on various projects on the coal-fired steam electric generating units. I also performed a number of inspections and condition assessments for boiler tube components for the coal-fired units.

In 1989, I transferred into the Corporate Environmental Affairs Department as a Staff Air Quality Engineer, working on what became the 1990 amendments to the Clean Air Act ("CAA"). CIPS then announced a merger with Union Electric ("UE") in mid-1995. Shortly thereafter, the CIPS environmental department, including its air quality group, started working with UE's environmental group. I worked at both the CIPS offices and the UE offices and then moved to St. Louis in 1997 and worked in what became Ameren's main office effective January 1, 1998. I worked on air quality issues in the Air Quality Group of the Environmental Services Department ("ESD") with the expanded Ameren team. I supported both Illinois electric generating units and Missouri units on air quality issues.

In 1999, I became Supervisor of the Air Quality Group within ESD. I remained in that role, leading the group that provided support to both Missouri and Illinois units on compliance with air quality regulations, until 2007. In 2007, I was promoted to Manager of ESD, which had responsibility for water quality and solid waste management in addition to air quality issues for the Illinois and Missouri plants. In January 2015, I became Senior Director of ESD. Although I held that position until my retirement, we went through another reorganization in 2018 in which the environmental team was bifurcated with one group supporting Ameren Missouri and another group in Ameren Services supporting Ameren Illinois and Ameren Transmission. I continued to lead the environmental services staff for Ameren Missouri until my retirement in late 2022.

As Manager (later retitled "Director") of ESD from 2007 to 2015, my job responsibilities and that of my staff included supporting Ameren Missouri (and its Illinois affiliates) in their respective business operations to ensure compliance with federal and state environmental regulations and for preparing each operating company's submissions to regulatory agencies, including permit applications and other authorizations.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to provide the Commission with the facts concerning (1) the role of ESD in Ameren Missouri's compliance with the Clean Air Act, including its NSR program; (2) the efforts that ESD took to understand the requirements of the Clean Air Act, including NSR; (3) the understanding that ESD had concerning NSR requirements; (4) the process by which ESD made determinations of NSR applicability; and (5) when, how and why Ameren Missouri concluded that the Rush Island Projects[1] would not (and did not) trigger NSR.

III. ROLE OF ESD IN ENVIRONMENTAL COMPLIANCE (2005-2010)

Q. To follow up on your employment history, can you describe the Company's organizational structure in the mid- to late-2000s?

A. Yes. There were four major business segments under Ameren Corporation at the time: Ameren Energy Generating Company, Ameren Illinois, Ameren Missouri, and Ameren Services Company ("Ameren Services"). Ameren Services was created in 1998, following the merger of CIPS and UE, to house the business and corporate services, including legal and environmental support groups, that would support both the Missouri affiliates and the Illinois affiliates. From 1998 through February 2018, all of the environmental support for both Missouri operations and Illinois operations was provided by ESD within Ameren Services.

[1] The projects performed by Ameren Missouri at Rush Island in 2007 and 2010 that were the subject of the NSR litigation.

Q. What role did ESD have in environmental compliance for the Ameren Missouri plants?

A. ESD employees, including me, were expected to be familiar with the applicable regulatory requirements so as to ensure environmental compliance in the plants. Because ESD supported both Ameren Missouri and its unregulated affiliates operating in Illinois, ESD was expected to understand the regulatory requirements in the separate jurisdictions and to apply them accordingly. ESD gained the required understanding of the applicable regulatory requirements by (1) reviewing the regulations applicable to each jurisdiction, (2) consulting with regulators and industry organizations knowledgeable on the regulatory programs, and (3) consulting with the Ameren Services Legal Department, as necessary. Below, I will discuss the relevant input that ESD received on NSR as a result of these activities.

In addition to understanding the applicable regulatory requirements, ESD employees also had the job of interfacing with the environmental regulators, as needed. Because Missouri had an approved state implementation plan (the "Missouri SIP"), the Missouri Department of Natural Resources ("MDNR") was the lead agency for implementation of the CAA (including NSR) in Missouri.

Finally, ESD played the lead role in evaluating whether environmental permits were required for activities the operating companies undertake. This includes evaluating whether NSR or other construction permits are required. Typically, we would reach a consensus decision within ESD on permit applicability through collaborative discussion. If we determined that permitting was required, then ESD took the lead in preparing applications for any required environmental permits. In fulfilling these functions, ESD would obtain the necessary information about the activity or project at issue from those persons directly involved in its planning or implementation.

Q. Were there specific individuals within ESD tasked with understanding the requirements of NSR?

A. Yes, this was considered part of the job for those of us in the Air Quality Group. I worked in the Air Quality Group for Ameren Services (or its predecessors) from 1989 until my promotion to head of ESD in 2007. Throughout that period of time, the Air Quality Group reviewed projects for potential NSR applicability a countless number of times, for both Missouri units and Illinois units.

After I was promoted to lead ESD in 2007, I remained involved in air quality issues. I continued to work with others in the Air Quality Group on reviews of proposed projects for potential NSR applicability for both Illinois and Missouri units. I continued my efforts to remain up to speed on developments concerning NSR and its requirements throughout my tenure at the Company.

IV. STEPS TAKEN BY ESD TO UNDERSTAND NSR

Q. How did the Air Quality Group in ESD become familiar with the requirements of NSR?

A. There were several means used to enable staff to become familiar with NSR requirements, which I will summarize. First, those of us assigned to the Air Quality Group read the regulations: the Missouri regulations on permitting found in the Missouri SIP and the federal NSR regulations.[2] Second, ESD employees consulted with regulators and with industry groups

[2] In Illinois, the federal NSR regulations were directly applicable because Illinois was a delegated state. Unlike Missouri, Illinois did not establish its own NSR program and have it approved by EPA in a state implementation plan.

knowledgeable about the NSR regulations. Third, ESD employees relied upon public statements by state and federal regulators on the requirements of NSR, including guidance on how to determine whether a project would trigger NSR.

Q. Can you provide some examples of the consultations ESD employees had with regulators and with industry groups regarding NSR?

A. Yes. At both a national and state level, Ameren was a member of a number of industry organizations and regulatory groups which focused solely on environmental legislation and regulations facing the electric utility industry. Environmental Services' staff worked with these industry groups and directly with local, state and federal environmental regulators to keep abreast of and influence new and developing environmental requirements. See Schedule SCW-D1 (2008 Environmental Compliance Plan, Appendix A).

For example, ESD employees participated in forums with MDNR and other electric utilities in Missouri, at which NSR was discussed. One of these was the Missouri Electric Utilities Environmental Committee ("MEUEC"), a group comprised of the electric utilities in Missouri for the purpose of sharing information about regulatory requirements and approaches to compliance. A similar organization in Illinois in which the Company participated was the Air Utility Group of Illinois ("AUGI"). Both of these state-level organizations served as a forum for discussing NSR requirements and approaches to NSR applicability decisions. MEUEC hosted meetings, several of which included MDNR representatives. MEUEC also hosted sessions devoted to educating MDNR representatives on utility operations and practice. And MEUEC also had permitting workshops in which MDNR representatives participated. MDNR in turn also hosted permitting workshops for utilities and other stakeholders. In these MEUEC/MDNR meetings, we regularly discussed the NSR requirements of the Missouri SIP.

MEUEC and AUGI were not the only state-level groups where ESD employees discussed NSR with regulators and with other members of the regulated community. In addition to MEUEC and AUGI, ESD representatives also participated in broader state-level groups, which included members in other industries as well as electric utilities, that also focused on air regulations. In Missouri, this was the Regulatory Environmental Group for Missouri ("REGFORM"). It Illinois, it was the Illinois Environmental Regulatory Group ("IERG"). REGFORM met quarterly, typically with MDNR representatives in attendance. REGFORM also presented topical seminars – such as a two-day annual air quality seminar that included environmental professionals as well as MDNR representatives. I specifically recall discussing the requirements for construction permitting, including NSR, with MDNR representatives in both MEUEC meetings and in REGFORM meetings.

In addition to the state-level coordination with other utilities and interaction with the state regulators on the topic of NSR, Ameren also worked with utilities outside of our jurisdictions on the topic of NSR. The primary nationwide utility group with which Ameren worked on NSR was the Utility Air Regulatory Group ("UARG").

Q. What was UARG?

A. UARG was an organization made up of individual electric utility generating companies and national trade associations. One of UARG's purposes was to provide members like Ameren detailed information about EPA's actions in every sphere of the Clean Air Act. It did this through various committees, including the Plant Repair, Enforcement, and Permitting ("PREP") Committee that focused on NSR. It was governed by a Policy Committee, which set the overall agenda and annual budget for the organization. UARG was represented by the law firm of Hunton & Williams LLP

("Hunton"). Hunton was recognized by the electric utility industry as having particular expertise in NSR, having represented electric utility companies in commenting on every proposed NSR rulemaking (and in the litigation over those NSR rulemakings) since the inception of the program in the 1977 Clean Air Act amendments.[3]

NSR was a subject of many discussions, memoranda and briefings I and my ESD colleagues received through our participation in UARG on behalf of Ameren. Ameren was an active participant in UARG throughout my tenure in ESD. I was Ameren's representative on the Policy Committee, on the PREP Committee, and at times on the Control Technologies Committee.

These UARG committees met regularly throughout the course of each year, and also received email updates from Hunton between such meetings. Hunton attorneys used these communications to update UARG member representatives, including myself, on developments relating to NSR. As issues arose concerning NSR, the Hunton attorneys would distribute memoranda analyzing these developments. In addition, Hunton attorneys would update UARG members on developments relating to NSR at regularly-scheduled committee meetings or workshops. These meetings or workshops incorporated presentations from Hunton attorneys on NSR, discussions among members on the topic of NSR, and sometimes presentations by EPA staff on NSR.

Q. Can you provide some specific examples of the information on NSR provided to the UARG?

[3] Another purpose of UARG was to serve as the body through which utilities like Ameren could collectively comment on proposed EPA rules under the CAA, including proposed NSR regulations, and litigation over the validity of those rules. UARG, represented by Hunton, participated in all those NSR rulemakings and litigation challenges.

A. Yes. Examples of the memoranda and presentations made to me and other Ameren representatives on UARG concerning NSR are the following:

- Schedule SCW-D2 is a true and correct copy of an email I sent to my ESD colleague Ken Anderson dated August 28, 2003, enclosing a memorandum from Hunton to the UARG PREP Committee on an important decision in EPA's utility enforcement initiative.

- Schedule SCW-D3 is a true and correct copy of a memorandum from Hunton to the UARG PREP Committee dated September 9, 2003, describing EPA's changes to the NSR regulations and how they conflicted with EPA's enforcement interpretation of NSR.

- Schedule SCW-D4 is a true and correct copy of a PowerPoint presentation made by Hunton at a UARG Control Technologies Committee meeting on March 11, 2004, on EPA's NSR enforcement initiative.

- Schedule SCW-D5 is a true and correct copy of a memorandum from Hunton to the UARG PREP Committee dated October 20, 2005, describing EPA's proposal to change the "emissions increase" test for NSR applicability and EPA's decision to pause its NSR enforcement initiative.

- Schedule SCW-D6 is a true and correct copy of a memorandum from Hunton to the UARG PREP Committee dated May 16, 2007, subject to redactions ordered by the U.S. District Court in the NSR case for privileged material, describing the allegations made by EPA in its NSR enforcement initiative as of that date.

- Schedule SCW-D7 is a true and correct copy of an email I received from Hunton dated August 30, 2007 concerning an upcoming workshop on NSR project review.

- Schedule SCW-D8 is a true and correct copy of an email I received from Hunton dated September 25, 2007 concerning the same workshop on NSR project review, announcing that it would include a presentation by an EPA official on NSR applicability. Attached to that email is the agenda for that "NSR Project Evaluation Workshop."

- Schedule SCW-D9 is a true and correct copy of the PowerPoint presentation delivered by Hunton at the aforementioned NSR Project Evaluation Workshop held on October 9, 2007, subject to redactions made by the U.S. District Court in the NSR case for privileged material.

- Schedule SCW-D10 is a true and correct copy of the PowerPoint presentation delivered by Hunton at a meeting of the UARG Control Technologies Committee on April 17, 2009, subject to redactions ordered by the U.S. District Court in the NSR case for privileged material.

- Schedule SCW-D11 is a true and correct copy of the PowerPoint presentation delivered by Hunton at a meeting of the UARG PREP Committee on April 28, 2009 concerning EPA's NSR enforcement initiative.

- Schedule SCW-D12 is a true and correct copy of the hand-out accompanying SCW-D9, on which I made handwritten notes during the course of that presentation by the Hunton attorneys.

- Schedule SCW-D13 is a true and correct copy of the PowerPoint presentation delivered by Hunton at that same meeting of the UARG PREP on April 28, 2009, concerning project evaluations for NSR applicability, which has been redacted by order of the U.S. District Court in the NSR case to preserve the confidentiality of privileged material.

- Schedule SCW-D14 is a true and correct copy of the hand-out accompanying SCW-D13, on which I made handwritten notes during the course of that presentation by the Hunton attorneys. Like Schedule SCW-D13, Schedule SCW-D14 has been redacted by order of the U.S. District Court to preserve the confidentiality of privileged material.

- Schedule SCW-D15 is a true and correct copy of a PowerPoint presentation delivered by Hunton at the UARG Policy Committee Meeting of December 4, 2009, concerning the activities of the UARG PREP Committee. Schedule SCW-D15 has been redacted by order of the U.S. District Court to preserve the confidentiality of privileged material.

- Schedule SCW-D16 is a true and correct copy of a PowerPoint presentation delivered by Hunton at the UARG Policy Committee Meeting of December 3, 2010, concerning the activities of the UARG PREP Committee. Schedule SCW-D16 has been redacted by order of the U.S. District Court to preserve the confidentiality of privileged material.

- Schedule SCW-D17 is a true and correct copy of a PowerPoint presentation delivered by Hunton at the UARG Control Technologies Committee meeting of April 7, 2011. Schedule SCW-D17 has been redacted by order of the U.S. District Court to preserve the confidentiality of privileged material.

- Schedule SCW-D18 is a true and correct copy of a PowerPoint presentation delivered by Hunton at the UARG Planning Workshop on June 2-3, 2011, concerning the activities of the PREP Committee. Schedule SCW-D18 has been redacted by order of the U.S. District Court to preserve the confidentiality of privileged material.

Q. How much effort did ESD employees undertake to make sure they understood NSR requirements as would apply in both Missouri and Illinois?

A. I and other ESD employees spent significant time and effort to understand NSR and to keep up with developments on that front. This included reading the NSR regulations, examining EPA's public statements on NSR, receiving briefings on NSR from regulators and industry experts, and discussing with similarly situated utilities the meaning of the NSR rules and their potential applicability to projects.

Many of these activities took place within meetings of UARG, MEUEC and REGFORM. For example, at the NSR Project Evaluation Workshop in October 2007, topics for discussion included **____

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______**. Schedule SCW-D8. I attended this workshop as a representative of Ameren, as reflected on the attendance sheet attached as Schedule SCW-D19.

V. ESD's UNDERSTANDING OF NSR (2005-2010)

Q. Can you provide an overview of ESD's understanding of NSR in the 2005-2010 timeframe?

A. NSR was a program under the CAA that concerned activities at stationary sources of emissions. Emissions from stationary sources are regulated on a state-by-state level through different state programs authorized by the CAA. As a result, not every state has an identical NSR program. When discussing NSR requirements, one therefore has to distinguish between approved state NSR programs, where the state writes its own regulations in an EPA-approved state implementation plan (as was the case in Missouri), and delegated state NSR programs, where the federal NSR rules are directly applicable (as was the case in Illinois). And within any particular state, there are two different NSR review programs depending upon whether the specific area is in compliance with the National Ambient Air Quality Standards ("NAAQS"). For areas that are in attainment of the NAAQS, a specific set of NSR rules called the "Prevention of Significant Deterioration" ("PSD") regulations apply. For areas that fail to meet the NAAQS, the specific set of NSR rules are found in the "Non-attainment New Source Review" ("NNSR") regulations. The applicability provisions of both PSD and NNSR are generally the same, so I and others working with these regulations generally refer to "New Source Review" or "NSR" to mean both PSD and NNSR.

As I said, the particulars of the NSR program can vary from state to state. But in general, the NSR programs required pre-construction permitting for either the construction of a new major source of emissions or the construction of a "major modification" to an existing major stationary source of emissions. Whether a proposed activity would meet the regulatory definition of "major modification" was to be determined by the source itself. Pre-project review or determinations by the permitting agency was not required.

Q. Can you describe ESD's understanding in the 2005-2010 timeframe of when NSR would apply to sources in Missouri?

A. From before the time I began working with sources in Missouri in the mid 1990s (as a result of the merger between CIPS and Union Electric), Missouri had an EPA-approved state NSR program—i.e., the Missouri SIP. Missouri included the NSR program in its Construction Permitting Rule, 10 C.S.R. 10-6.060 (2006), and EPA approved these regulations as consistent with the CAA by approving the Missouri SIP. 10 C.S.R. 10-6.060 (2006) described when preconstruction permitting is required, and if so what sorts of preconstruction permits might apply to different activities. I and others in ESD read these regulations to require preconstruction permitting only for the “construction” of a new source of emissions or the “modification” of an existing source of emissions, which was defined as an activity that would increase the unit’s annual rate of potential emissions. If either “construction” or “modification” would occur as defined by the Missouri SIP, then one had to look at the remainder of the regulation to determine what sort of permit might apply: either a minor source permit if the increase in potential emissions was minor, or an NSR permit if there would also be a “major modification” as defined in 40 C.F.R. § 52.21. But if neither “construction” or “modification” occurred under the SIP (i.e., if there was no increase in potential annual emissions), we read the regulation as not requiring any permit at all. This was how we understood NSR to apply in Missouri.

Q. Why did you believe that Ameren Missouri’s understanding of NSR applicability for sources in Missouri was correct?

A. This seemed to us to be the most straightforward way to read the regulations, as requiring permitting only for “construction” or “modification,” with “modification” defined explicitly as an increase in potential annual emissions. But we also knew that this understanding was also shared by other utilities in Missouri and by MDNR itself.

Q. How did you know that MDNR agreed with ESD’s interpretation of the Missouri SIP?

A. I had many conversations with other utilities and with MDNR representatives over the years. Some of these took place in meetings of MEUEC. Others occurred in the REGFORM meetings. Still others took place in smaller meetings or one-on-one conversations. I and my colleagues at other companies in MEUEC and REGFORM were well aware of MDNR’s interpretation and application of the Construction Permitting Rule in the Missouri SIP.

We were also aware of several letters MDNR had issued to other utilities confirming that no permitting was required under the Missouri SIP unless a project would increase the rate of potential annual emissions. Such letters were discussed and shared within MEUEC meetings. We were also aware of MDNR guidance issued on the application of the Construction Permitting Rule, which confirmed this approach. An example of such guidance is attached hereto as Schedule SCW-D20. Finally, MDNR regularly sent inspectors out to the plants to review compliance with the SIP and all existing permit requirements. These MDNR inspectors conducted site visits when several of our boiler outages were in progress (at Rush Island and elsewhere) and witnessed the Rush Island Projects and others just like them performed across the Ameren Missouri system. In fact, MDNR inspectors preferred to visit our coal-fired plants when a unit was in outage so that they could examine the unit more carefully, as it was offline and opened up for maintenance, repair and replacement activities. I am aware that MDNR inspectors were on-site and witnessed both the Rush Island Unit 1 outage work in 2007 and the Rush Island Unit 2 outage work in 2010. To my knowledge, not once during all of these MDNR inspections of the Rush Island Projects and the many other similar projects at other units did anybody from MDNR suggest that construction permitting requirements might have applied. All of this supported our conclusion that Ameren Missouri, the other utilities in Missouri, and MDNR were in alignment that no permitting requirements applied to work on an existing unit unless that would increase the unit's potential emissions and therefore be a "modification" under the Missouri SIP.

In addition to all that I have described above, several post-project developments confirmed that ESD had correctly understood MDNR's position that no construction permitting is required under the Missouri SIP (including no NSR permitting) unless the project would be a "modification" by increasing the potential emissions. For example, MDNR did not identify NSR as an "applicable requirement" in its renewal of the Rush Island Title V permit in August 2010, despite its knowledge of the work performed during the 2007 and 2010 outages. In addition, MDNR did not join in EPA's allegations that Ameren Missouri had violated the Missouri SIP's permitting requirements. This reinforced our understanding that Ameren Missouri and MDNR were in alignment on the applicable legal requirements. Finally, I had the opportunity to sit in on the deposition of Kyra Moore, Director of MDNR's Air Pollution Control Program, taken in the NSR litigation. Ameren Missouri expert witnesses Holmstead and Moor cite her deposition testimony in their Direct Testimonies submitted contemporaneously with mine. The testimony that I witnessed Ms. Moore give in that deposition regarding the meaning and application of the Missouri SIP was entirely consistent with the many conversations that she and I had previously had on the topic. Long after the projects were completed and the litigation over them commenced, we continued to understand that Ameren Missouri and MDNR were aligned on (1) the relevant legal requirements for NSR permitting under the Missouri SIP and (2) the understanding that Rush Island Projects did not trigger NSR permitting under those legal requirements.

Q. Can you describe ESD's understanding of NSR applicability in Illinois?

A. Because Illinois was a delegated state, the federal NSR rules starting at 40 C.F.R. § 52.21 were directly applicable. Thus, once EPA updated the federal NSR rules in 2002 the new requirements of those rules started to apply in Illinois. EPA's 2002 NSR rules required permitting for any non-routine project in Illinois that would be expected to cause actual annual emissions to increase significantly—even without an increase in potential emissions.[4] The

[4] No matter what the emissions impact may be, the NSR regulations exclude "routine maintenance, repair and replacement" from NSR permitting requirements.

upshot for ESD was that once EPA's 2002 NSR rules became final, ESD was doing different emissions analyses in Illinois from those it was doing in Missouri. In Missouri, ESD was applying the Missouri SIP and looking for "modifications" that would require permitting because they would increase potential emissions. In Illinois, ESD was applying the federal NSR rules and looking for "major modifications" that would require NSR permitting because they would increase actual annual emissions.

Q. What did you learn from UARG about the applicability provisions of the federal NSR rules, directly applicable in Illinois?

A. The discussions coordinated by the Hunton attorneys on the federal NSR rules conveyed the following information to me and my colleagues at Ameren:

1) The federal NSR rules required NSR permits only for "major modifications," which those rules define as a "physical change or change in the method of operation" that "would result" in a "significant net emissions increase" of "actual annual emissions." Schedule SCW-D9; Schedule SCW-D13.

2) The federal NSR rules exclude from permitting requirements "routine maintenance, repair and replacement" activities—no matter their emissions impact. Schedule SCW-D3.

3) The federal NSR rules allow for flexibility in doing emissions analyses. No future actual annual emissions projection methodology is spelled out in any EPA rule or guidance. Schedule SCW-D11; Schedule SCW-D12.

4) Reflecting the flexibility inherent in the NSR rules, courts were using different emissions increase methodologies. One court in particular held that a utility cannot be held liable unless all reasonable methodologies under the rules would have projected a significant actual annual emissions increase. Schedule SCW-D13, Schedule SCW-D14; Schedule SCW-D15.

5) A project must be "the predominant cause" of an actual annual emissions increase for NSR to apply. Emissions resulting from increased demand do not count. Schedule SCW-D9; Schedule SCW-D13; Schedule SCW-D14.

6) EPA stated that a source can subtract from its future actual annual emissions projections all of the emissions that the unit could have accommodated during the baseline period and are unrelated to the work at issue. This means, according to EPA, that the NSR emissions increase test under the existing rules

"is not substantially different" from a test that looks exclusively to whether the work would increase the hourly rate (i.e., potential emissions) of the units. Schedule SCW-D9; Schedule SCW-D13; Schedule SCW-D14.

7) Other states and EPA were confirming that component replacement projects at electric utilities would not trigger NSR where (a) the unit could have operated at the projected levels in the baseline, even before the work was done, (b) the work would not increase the emission rate per unit of output, and (c) there was no expected change in the system dispatch order. In such cases, any increase in actual annual emissions after the work could be attributed to demand rather than to the project at issue. Schedule SCW-D9; Schedule SCW-D13; Schedule SCW-D14.

8) Finally, the actual annual emissions calculations EPA had used to date in the NSR enforcement initiative against electric utilities had the problem of assuming causation, and could not demonstrate causation of an emissions increase are required by the statute and the rules. As a result, neither EPA nor any state agency has issued any guidance endorsing the use of that litigation-based approach to determining NSR applicability. Schedule SCW-D9; Schedule SCW-D13; Schedule SCW-D14.

The big "take-away" for me from the discussion of the federal NSR rules in the UARG meetings was that a utility is not required to do any emissions analyses for projects that are routine. But if such analyses are needed, all that is required by the NSR rules is that the utility make a reasonable estimate of emissions impact, applying its engineering judgment, and examine the facts to determine whether the proposed "change" to the unit would be the "predominant cause" of a projected increase in actual annual emissions. If that reasonable estimate concludes that there would be no increase, or that any increase would be unrelated to the projects, then there would be no "major modification" and the source need not apply for an NSR permit.

Q. What did you learn from UARG about EPA's NSR enforcement initiative?

A. UARG kept its members apprised of developments in EPA's utility enforcement initiative. As Schedules SCW-D2 through SCW-D18 illustrate, UARG made Ameren Missouri aware of the following facts:

- EPA began its enforcement initiative against electric utilities in November 1999 with a series of actions filed against investor-owned utilities and an administrative action against TVA, the federal government's own electric utility. EPA alleged that nearly 550 projects conducted at 148 coal-fired units over the prior 20 years had violated NSR. The challenged boiler projects were generally tube replacements (economizers, superheaters, reheaters, and waterwalls) as well as auxiliary equipment replacements (e.g., pulverizers). **______________________ ____

  ** Schedule SCW-D4 (PowerPoint Presentation from Hunton & Williams LLP to UARG Control Technologies Committee, "Update on Utility Enforcement Initiative," Mar. 11, 2004).

- The EPA litigation positions were based upon a **__________________________ ____ ______________________ ** of the NSR program held by both EPA and utilities. Schedule SCW-D4.

- The EPA litigation positions conflicted with the views of EPA's Administrator and the program office responsible for the NSR rules. Schedule SCW-D3; Schedule SCW-D5.

- By the spring of 2007, over 20 utilities and 80 plants faced claims for projects that were substantially the same as the Rush Island Projects. Schedule SCW-D6 (Memorandum from Hunton & Williams LLP to UARG PREP Committee, May 16, 2007). The majority of similarly situated utilities were resisting EPA's claims. Schedule SCW-D4; Schedule SCW-D6.

- Those utilities that had entered into settlements with EPA did so when the settlements overlapped with pre-existing company business plans, e.g., they agreed to add pollution control equipment as part of the settlement if the utility's business plan was to add such equipment regardless of the litigation. Schedule SCW-D4; Schedule SCW-D10.

- As of 2005, EPA announced it would not file new enforcement cases under the theories that it had advanced in commencing the utility enforcement initiative. Schedule SCW-D5. This pause on EPA's NSR enforcement initiative lasted through 2007.

- As of 2009, courts were generally ruling with utilities that RMRR is routine in the industry, rejecting EPA's position that RMRR excludes only what would be routine at the unit in question. Schedule SCW-D10 (PowerPoint Presentation from Hunton & Williams LLP to UARG Control Technologies Committee, "Utility Enforcement Initiative and NSR Rules," April 17, 2009).

- As of 2010, courts were also rejecting EPA's emissions increase claims, and refusing to automatically apply the Koppe-Sahu emissions projections method. Schedule SCW-D15 (PowerPoint Presentation to UARG Policy Committee, "Plant Repair, Enforcement, and Permitting (PREP) Committee," Dec. 4, 2009); Schedule SCW-D16 (PowerPoint Presentation to UARG Policy Committee, "Plant Repair, Enforcement, and Permitting (PREP) Committee" Dec. 3, 2010).

- The rules did not provide instructions on calculating actual annual emissions before and after projects, and that courts were finding that utilities simply had to make a reasonable projection of future actual annual emissions increases in order to comply. Schedule SCW-D11 (PowerPoint Presentation by Hunton & Williams to UARG PREP Committee, "NSR Enforcement Initiative," April 28, 2009); Schedule SCW-D12 (same, with handwritten notes).

- The utility industry recognized EPA's litigation theory of emissions increase proffered by Koppe and Sahu as **____________________** if any project replaced a component that had caused a forced outage or derate in the baseline period, it would automatically be found to have increased actual annual emissions. Schedule SCW-D9 (PowerPoint Presentation by Hunton & Williams at UARG NSR Project Evaluation Workshop, "Emissions Increase Analysis Under NSR Rules" Oct. 9, 2007).

- One court found that liability could not attach unless all reasonable methodologies would show that a project caused an actual annual emissions increase. Schedule SCW-D11 ("Plaintiffs' burden is not to demonstrate[] just that Allegheny might have projected a significant net increase . . . [but rather] that ***all*** reasonable methodologies ***must*** have projected a significant net increase such that Defendants' failure to obtain a permit at the time was unreasonable." (quoting PA DEP v. Allegheny, W.D. Pa.) (emphasis in original); Schedule SCW-D13 (same).

- Utilities were generally prevailing in the cases brought in the enforcement initiative. Schedule SCW-D11; Schedule SCW-D15; Schedule SCW-D16; Schedule SCW-D18 (PowerPoint Presentation by Hunton & Williams at UARG Planning Workshop, "Plant Repair, Enforcement, and Permitting (PREP) Committee" June 2-3, 2011).

- Outside of the enforcement initiative, regulators were not requiring application of the Koppe-Sahu emissions calculations. Rather, regulators, considering projects similar to Ameren Missouri's, had accepted calculations showing there to be no increase in emissions (1) if a unit could have operated in baseline at the projected levels (2) when there was no increase in emissions rate per unit of output and (3) no change in the dispatch order. In other words, emissions increases in these circumstances should be attributed to projected demand increase and not presumed to be caused by the component replacement. Schedule SCW-D9; Schedule SCW-D13; Schedule SC W-D14.

The January 2010 NOV that EPA issued to Ameren Missouri was the first time in EPA's enforcement initiative that EPA alleged any noncompliance with the Construction Permitting Rule in the Missouri SIP.

Q. How did this understanding of EPA's enforcement initiative impact ESD's evaluation of projects for Ameren Missouri or its Illinois affiliates?

A. For me, there were four big "take-aways" from the UARG discussions about EPA's utility enforcement initiative. The first point was that Ameren Missouri and its Illinois affiliates were performing work just like others had done in the utility industry. The second point is something that we already understood from our conversations with other utilities: nobody had been seeking NSR permits for projects like these. Documents like Schedule SCW-D6 make both of these points plain. The third point is that although EPA's allegations of non-compliance were widespread, it was having difficulty establishing these claims in court. Documents like Schedules SCW-D10 through SCW-D18 show that EPA was losing more often than it was winning in these cases. Finally, the communications within UARG about the enforcement initiative highlighted the importance of ESD doing a careful evaluation of proposed projects for potential NSR applicability. And that is what we endeavored to do.

VI. PROCESS FOR ESD DETERMINATIONS OF NSR APPLICABILITY

Q. Did ESD have a process for review of upcoming projects for potential NSR applicability?

A. Absolutely. ESD had a standardized process in place from the fall of 1997, as the environmental department of CIPS merged with the environmental department of UE, for the review of projects for potential NSR applicability. The process evolved some over time, eventually incorporating more documentation as the law changed and as internal procedures were formally updated, but from at least 1997 through my last day at the Company, I can confidently state that ESD had a process and work flow to ensure that projects got the necessary review for potential NSR applicability.

Q. In the 2005-2010 timeframe, as projects were identified by Ameren Missouri for its plants, when and how would ESD get involved?

A. For capital projects performed during scheduled unit outages—like the Rush Island Projects—many different work groups would typically be involved in the planning and approval process. This would include representatives from project engineering, generation, the plants, accounting, corporate planning, ESD and potentially the Legal Department. ESD would get involved in one of two ways. Generally, those involved in a project in generation or project engineering would reach out to ESD to advise ESD of upcoming outage projects and to consult with ESD on whether any permitting would be required. ESD also reviewed the published outage schedules—published within Ameren Missouri by the Generation Department—and would reach out to the project engineers and the generation department to discuss the scope of upcoming outage work if those individuals had not already initiated the consultations with ESD. These discussions were typically by telephone or in face-to-face meetings.

When a question came to ESD about air permits, these were referred to the Air Quality Group within ESD. Thus, someone from the Air Quality Group would be tasked with answering the question of whether anything in an upcoming outage would require NSR permitting. In that permitting review, ESD staff would consult with the project engineers and get an understanding of the nature and scope of the work proposed. ESD staff would also consult with performance engineers to get information on specific parameters, such as the unit heat rate, heat input capacity, steam generating capacity, and generation output. We would also consult with other Ameren departments (for example, Corporate Planning) as needed. Many of these interactions were verbal, not documented. For air issues in the 2005-2010 timeframe, I was one of the primary ESD contacts for the project planners and engineers.

ESD staff had considerable knowledge and experience (in all instances, over 10 years' experience) with assessing permit applicability regarding all manner of projects at Ameren, including component replacements at Ameren's power plants. ESD staff used that knowledge and prior experience in assessing projects for NSR applicability.

If I required assistance in determining NSR applicability, I would consult with the Ameren Legal Department. After the Air Quality Group in ESD completed its review, we would report back to the project engineering group. In addition, if we concluded that a permit was required, then ESD would initiate the permitting process.

Q. How did the project engineers know that they were to run projects by ESD for a review of any permitting requirements?

A. This was standard operating procedure for both the Missouri and the Illinois operating companies. I and others within ESD consistently delivered this message to the project engineering staff and the generation department. In various meetings and presentations ESD made to the generation department, to engineering staff, and to upper management, I and others in ESD made the point that ESD needed to be brought in as early as possible in the planning of projects so as to perform a screening for NSR applicability. For example, ESD set up "Environmental Update" meetings for the operating companies multiple times per year, and held these a central office locations as well as at the plants themselves. I attended many of these, and made sure that the message was delivered: consult with ESD as early as possible on any future project, to make sure that ESD can provide the necessary NSR review.

We made a particular point to emphasize that replacement of boiler tube components (e.g., economizer, superheater, reheater or waterwall components) should be brought to ESD for discussion and evaluation for potential NSR applicability. ESD emphasized that replacements of economizers, superheaters, reheaters and waterwalls needed to be reviewed by ESD, because we were aware that such component replacements had been targeted by EPA in its ongoing NSR enforcement initiative. Schedule SCW-D6. ESD emphasized the need for at least a 6-12 month lead time for completion of the necessary screening.

Q. What information did ESD request during project planning in order to perform the NSR review?

A. Although this could vary depending upon the particulars of certain projects, in general the Air Quality Group would ask the project engineers or generation staff to provide a description of the work to be performed (i.e., what components would be repaired and replaced) and whether there would be any change in design of the unit (i.e. a change in heat input capacity or steam flow capacity because if there was no change, then there could be no potential emissions increase). Information on operating characteristics of the unit (e.g., annual capacity factor and annual availability factor) was readily available, and consulted by ESD.

Q. How frequently was ESD called upon to make permitting decisions?

A. In supporting both Ameren Missouri and its Illinois affiliates, this was a regular occurrence for ESD. There were multiple outages scheduled every spring and fall across both fleets, making the evaluation of projects for potential NSR applicability a continual process. Within ESD, work was being done to evaluate some project for permitting on an almost daily basis.

Q. Can you provide a specific example of how this worked?

A. Yes. Although this example concerns an Illinois unit, the process was the same for Ameren Missouri projects as well. (As a noted above, ESD was a "shared services" department within Ameren Services Company that supported both Ameren Missouri and the Illinois affiliates.) In 2006, it was decided to uprate a coal-fired unit at Duck Creek by increasing the capacity of the coal mills on the boiler, at the same time that other work was being performed. The purpose of this work was to increase the maximum continuous rating of the boiler (in pounds per hour of steam) to take advantage of the rated megawatt capacity of the turbine generator. Such a boiler uprate would have increased its potential emissions, because increasing the maximum fuel feed rate into the boiler would increase the maximum hourly emissions rate coming out of the boiler. ESD determined that this project at Duck Creek would trigger NSR, and therefore took the lead on obtaining the NSR permit. ESD obtained the necessary data from the plant and the project engineers, and prepared and submitted the permit application. Once ESD obtained the NSR permit in February 2007, Ameren Energy Resources proceeded with the boiler uprate and associated work.

In the case of Duck Creek, ESD determined that the project would trigger NSR and took action. If ESD determined that a project would not need a permit, then it would verbally report that decision and allow the project to proceed. This decision to proceed may or may not have been documented.

Q. Did it ever come to your attention that a project had been undertaken without first being evaluated for potential NSR applicability by ESD?

A. No. From time to time, ESD conducted internal audits and assessments to make sure that proper procedures were being followed and the plants remained in compliance. I cannot recall a single instance in which a project was undertaken without first undergoing the required review by ESD. I can recall some isolated examples in which ESD did not receive as much lead time as we would have liked in order to perform the necessary review, but even then the review was completed and a permitting decision made prior to commencement of the work. Had any project started without going through the necessary ESD review, we would have stopped it.

VII. ESD's CONCLUSIONS THAT THE RUSH ISLAND PROJECTS WOULD NOT TRIGGER NSR

A. Rush Island Unit 1 Projects (2007)

Q. Mr. Whitworth, were you aware of the 2007 projects at Rush Island Unit 1?

A. Yes. To the best of my recollection, I was notified of the work planned for the 2007 outage at Rush Island Unit 1 sometime in the summer of 2006.

Q. How were the upcoming Rush Island Unit 1 projects brought to your attention?

A. I recall the topic came up at a meeting with projects engineers and counsel for Ameren, which had been set up for another purpose. I cannot specifically recall who said what on this topic, but I do specifically recall that this was how the upcoming Rush Island Unit 1 projects came to my attention.

Q. What did you do after the upcoming Rush Island Unit 1 projects were brought to your attention in this meeting?

A. As head of the Air Quality Group at the time, I started a process to get the necessary information in order to assess the Rush Island Unit 1 projects for potential NSR applicability. To the best of my recollection, that information included information on the timing of the outage (including start date and estimated length), and details from the project engineers on the components at issue and the scope of the work contemplated. At this point in time for projects in Missouri, we did not request data in order to do an actual-to-projected-actual emissions calculation because those calculations were not required under the Missouri SIP as it existed at that time. In Missouri, the emissions question was whether the projects would cause a potential emissions increase and if the answer was "no," NSR permitting was not applicable.

Q. What did ESD know about the Rush Island Unit 1 Projects after assembling this information?

A. I was made aware that Ameren Missouri was planning an outage at Rush Island Unit 1 that would begin in February 2007 and last until May of that year. I was advised that during this outage, a number of different maintenance, repair and replacement projects would take place, as is typical practice for a coal-fired electric utility unit. I was also made aware that the projects scheduled for this outage included replacements of the reheater, the economizer, the lower slope tubes, and certain air preheater components, which I will refer to hereafter as the "Rush Island Unit 1 Projects." I was briefed on the nature and scope of the Rush Island Unit 1 Projects. I was advised that all of these projects were "like-kind" replacements, in that none of the replacements would change the function of any component or change the maximum hourly heat input capacity, the maximum hourly steam flow capacity, or the maximum hourly emissions rate.

ESD knew that the Rush Island Unit 1 Projects were similar to component replacement projects that had been performed over and over again across the Missouri and Illinois fleets supported by ESD. Throughout this time period, the same types of projects were brought over and over again to ESD for permitting review: boiler tube replacements (economizers, reheaters, superheaters, and waterwalls—of which the lower slopes are a part) and boiler auxiliary equipment repairs and replacements (air heaters, fans, pulverizers, pumps, etc.). I and others on the ESD staff had considerable knowledge and experience with assessing these types of projects, and recognized that they would not cause any increase in potential emissions or actual emissions.

Finally, we knew that the Rush Island Unit 1 Projects were much less extensive than the WEPCo Port Washington Project, where EPA had determined that the extensive rebuilding of five coal-fired units at successive nine-month outages, in order to increase maximum achievable capacity, would trigger NSR.

Q. What did ESD consider in making its assessment of whether the Rush Island Unit 1 Projects required NSR permitting?

A. Because Rush Island is located in Missouri, its CAA obligations were found in the Missouri SIP. The NSR requirements applicable to Rush Island and other major sources in Missouri were found in the Missouri SIP Construction Permitting Rule, 10 C.S.R. 10-6.060 (2006). Consideration of the Rush Island Projects therefore began there. We read and relied upon the text of the regulations. We also relied upon MDNR's settled interpretation and application of the Construction Permitting Rule in the context of boiler component replacement projects. The Construction Permitting Rule incorporated by reference the federal NSR rules (both the PSD regulations and the NNSR regulations). We therefore considered the plain language of the federal NSR rules and how those rules had been described and applied by EPA, state regulators, and the electric utility industry over the years. These were the key sources that informed our understanding of the law at the time.[5]

[5] Although I and others in ESD were aware of EPA's electric utility enforcement initiative and certain court rulings made in that enforcement initiative, ESD did not typically read and analyze court decisions as part of our efforts to understand the law. ESD relied upon lawyers in Ameren Services' Legal Department and the lawyers for UARG to summarize the key takeaways from these court cases.

As I have previously noted, if legal questions arose during the process of ESD review of a particular project, ESD would consult with the Ameren Services Legal Department. In the pre-project evaluations performed by ESD for the Rush Island Unit 1 Projects, I do not recall asking the Legal Department to weigh in on whether the projects would trigger NSR applicability because there wasn't any need to do so.

Q. In addition to your understanding of the applicable law in Missouri, what else did you consider in making your decision on whether the Rush Island Unit 1 Projects would trigger NSR permitting requirements?

A. Our evaluation of the Rush Island Unit 1 Projects considered the following, in addition to our understanding of the applicable law:

- The purpose, nature and scope of the projects;
- The similarity of these projects to countless other projects performed by Ameren Missouri, by its Illinois affiliate, and across the industry;
- Our knowledge of the role of demand in how much and when coal-fired electric generating units operate;
- Our knowledge of the historical operational characteristics, output, and capability of the units as published in internal company databases;
- Our experience with similar work on Ameren Missouri's and Illinois' units, and the pre- and post-outage emissions data for those units with which ESD works on a daily basis; and
- Our experience with performing emissions calculations for similar work on Illinois units, which showed that like-kind replacement of parts on existing units are not expected to cause any increase in actual annual emissions where, as here, the units had additional, untapped capacity to generate in the baseline period (i.e., in the absence of the proposed work) greater than any projected future annual operating level.

Q. What conclusion did ESD reach about the upcoming Rush Island Unit 1 Projects?

A. We concluded that the projects would not trigger any permitting requirements under the Missouri SIP, including any NSR permitting requirement. In reaching this conclusion, we considered the outage work as a whole.

Q. Why did you reach the conclusion that the Rush Island Unit 1 Projects would not trigger NSR permitting requirements under the Missouri SIP?

A. We had three independent reasons for concluding that the Rush Island Unit 1 Projects would not trigger NSR under the Missouri SIP, any one of which standing alone would have excluded the projects from NSR review. First, the Missouri SIP as both MDNR and we understood it at the time required permitting for a project on an existing source (e.g., Rush Island Unit 1) only if the project would constitute a "modification," which the SIP defined as an increase in the potential emissions from the facility. Based upon the description of the projects I received, nothing that would be done in the outage would have increased the potential emissions of Unit 1. That meant that the projects were excluded from NSR permitting for that reason alone.

Second, we did not believe that the Rush Island Projects would cause actual annual emissions to increase. If a project does not cause actual annual emissions to increase, then it is not a "major modification" as defined in the federal NSR regulations incorporated into the Missouri SIP, and thus it would not require any NSR permit.

Third, we considered all the Rush Island Unit 1 Projects to be the "routine maintenance, repair and replacement" of parts, which is explicitly excluded from NSR permitting requirements regardless of any emissions the work might cause.

Q. What was the factual basis for the conclusion that the Rush Island Unit 1 Projects would not cause an increase in potential emissions?

A. Based upon the description of the projects provided, these "like-kind" replacement of components would not increase the unit's maximum heat input capacity (i.e., the amount of coal the boiler could burn), maximum steaming rate (i.e., the pounds per hour of steam produced by the boiler), or its maximum hourly emissions rate (i.e., the pounds per hour of pollutants emitted through the stack). In short, nothing would change the unit's maximum annual rated design capacity given continuous year-round operations. Based on our considerable experience with NSR applicability determinations under the Missouri SIP, the language of the SIP, and MDNR's stated interpretation of the SIP, we understand that such projects would not increase the unit's annual rate of potential emissions, and therefore did not constitute "modifications" under the Missouri SIP. Accordingly, we determined that the Rush Island Unit 1 Projects would not trigger the application of the Missouri Construction Permit Rule, meaning no construction permit was required.

Q. Were there any calculations done to confirm that the Rush Island Unit 1 Projects would not increase the potential emissions of the Unit?

A. No, and none were required. First, this type of assessment is done all the time by ESD and other utility engineers. The formula for calculating potential annual emissions uses the maximum hourly emissions rate and multiplies it by the number of hours in a standard, non-leap year (8760 hours). That number of hours in a year (8760) never changes. Thus, the only way that potential emissions can increase at an existing facility is by increasing the maximum hourly emissions rate. Here, however, we were doing like-kind replacement of parts, maintaining the thermal performance of each component and the overall design capacity of the boiler. Once it is established that the like-kind replacements at issue will not change the heat input, steam output, or emissions rate of a boiler, then it is obvious that potential emissions will not increase—without having to resort to mathematical proof. This fundamental truth was also borne out by experience with the myriad like-kind boiler component replacements ESD had been involved with in the decades prior to 2007. With no change to a component that would increase the boiler's fuel flow, air flow, or steam flow, there can be no increase in the unit's potential emissions.

Second, there was no requirement in the Missouri SIP to supplement this sound engineering judgment with calculations. The requirement to perform calculations to assess potential NSR applicability were not incorporated into the Missouri SIP until long after the 2007 Rush Island Unit 1 Projects.

Q. The second reason you provided was that you did not believe the Rush Island Unit 1 Projects would cause actual annual emissions to increase. If ESD had already determined that the Rush Island Unit 1 Projects would not increase the potential emissions of the Unit, then why was it necessary to also consider actual annual emissions?

A. It was not necessary to examine actual annual emission under the Missouri SIP if there would be no increase in potential emissions. However, throughout this period of time ESD was performing assessments of whether projects at Ameren's Illinois plants would cause any changes in actual annual emissions. That work in Illinois made it clear to us that projects like these on well-maintained units like Rush Island are not expected to cause actual annual emissions to increase. This knowledge was part of the engineering judgment that we brought to every NSR assessment, regardless of the applicable regulations. Just like one cannot un-ring a bell, the Air Quality Group staff could not sever this knowledge and experience from its collective engineering judgment.

Q. What conclusions did you reach concerning actual annual emissions at Unit 1?

A. We did not believe that the Rush Island Unit 1 projects would cause Unit 1 to operate more in the future, and thus there would not be any increase in actual annual emissions caused by the Rush Island Unit 1 Projects.

Q. Why didn't you believe the projects would cause actual annual emissions to increase?

A. As I have noted, ESD had experience with and knowledge of many similar projects performed on the Ameren Missouri system and in Illinois in the years prior to the Rush Island Projects. Because ESD also has the job of tracking and reporting annual emissions from all of these plants, ESD was familiar with the emissions profile before and after similar projects were completed. In our considerable experience, changes in annual emissions are primarily caused by changes in emissions factors (i.e., fuel sulfur content, pollution control equipment, efficiency) or demand. In our experience, projects like those done at Rush Island do not cause actual annual emissions to increase.

A significant part of the collective ESD experience that informed this understanding were the emissions calculations that ESD was performing at that time for projects in Illinois to determine whether the federal NSR rules directly applicable in that delegated state would require permitting for any of the Illinois projects. In performing those calculations, ESD would first select the baseline annual emissions, from the emissions data for each unit that we worked with on a daily basis. As a second step in performing those calculations, we would project the annual emissions following the project for the Illinois unit in question. One significant input to that projection would be the projected annual operations provided by the system planning department, which modeled how each unit on the system was expected to run in the future. As a third step, ESD would compare the baseline annual emissions to the projected annual emissions for the Illinois unit in question, to determine whether there would be an increase expected in annual emissions. If there was such an increase expected, then ESD would proceed to the fourth step—determining whether the project would be the cause of the projected increase in annual emissions. ESD would do so by examining operations of the Illinois unit in the baseline period, and seeing what the annual emissions could have been prior to the project. If the unit could have accommodated the projected future operations in the baseline period (i.e., before the work at issue is done on the unit), then the logical conclusion is that any projected increase would have to be due to demand growth or other independent factors – not by the work at issue in the outage – and therefore the work would not be expected to result in a projected increase in emissions.

After performing similar analyses in Illinois over and over again, applying the federal NSR rules, a consistent pattern emerged. Where a unit has good availability, with additional (but unused) capacity to generate in the baseline period, the like-kind replacement of components as they wear will not cause annual emissions to increase. That understanding was consistent with the experience of other utilities across the country, as I learned in my participation in UARG meetings.

Here, we were aware that Rush Island Unit 1 had good availability and additional (unused) capacity to generate in the baseline period prior to the projects. Based upon our experience with applying the federal NSR rules in Illinois, and the experience of similar utilities across the country, there was no reason to expect that the Rush Island projects would cause annual emissions to increase. Rather, the ongoing demand growth that Ameren Missouri was experiencing in this timeframe would be the predominant cause of any increase in hours of operation or production rate of Rush Island Unit 1, and thus the predominant cause of any future actual annual emissions increase.

Because we did not expect that the Rush Island Projects would cause actual annual emissions to increase, we did not believe that the projects would be a "major modification" under the federal NSR rules incorporated into the Missouri SIP.

Q. The third reason you gave for why ESD concluded no permitting was required for the Rush Island Unit 1 Projects was that they were routine. What was the factual basis for that conclusion?

A. Under the federal PSD rules incorporated into the Missouri SIP, permitting is required only for a "physical change or change in the method of operation" of a unit that would result in a significant net emissions increase. These rules exclude "routine maintenance, repair and replacement" from the definition of "physical change or change in the method of operation." Thus, maintenance, repair and replacement activities do not require NSR permits—regardless of any emissions impact—if those activities are "routine."

The replacement of these boiler components and auxiliary equipment components at Rush Island Unit 1 are clearly "replacement" and "repair" activities. Moreover, these "replacement" and "repair" activities are commonly understood to be routine. ESD understood, from our conversations with the engineering personnel, that the projects at issue were like-kind replacement of existing components with new components that would be functionally equivalent. ESD and project engineering were in alignment that such replacements were commonly performed throughout the industry, and we had personal knowledge of dozens of similar component replacements performed on the Ameren Missouri system and the Illinois units in the years leading up to the Rush Island Projects. We had replaced economizers, reheaters, and waterwalls multiple times at Labadie, Meramec and Sioux. We had replaced air preheater components multiple times at the same plants, and at Rush Island as well.[6] We were also aware that other utilities regularly performed similar component replacement projects. This understanding was developed through our interactions with other utilities, including through UARG meetings.

On the basis of these facts, I and my colleagues in ESD determined that the Rush Island Projects constituted "routine maintenance, repair, and replacement" activities that are excluded from NSR permitting under the Missouri SIP.

Q. Did ESD document these conclusions concerning the non-applicability of NSR?

A. No.

Q. Why not?

A. That was not part of the process at the time, because the requirement for reporting and recordkeeping concerning NSR applicability decisions was not incorporated into the Missouri SIP until well after the 2007 Rush Island Unit 1 Projects. At the time of ESD's evaluation of the Rush Island Unit 1 Projects, additional paperwork was required only if ESD concluded that the proposed project would trigger NSR, and that was not the case here.

Q. What did you do after concluding that the Rush Island Unit 1 Projects would not trigger NSR?

A. I verbally reported my conclusions to the contacts in the generation department whom I was supporting on the project.

B. <u>Rush Island Unit 2 (2010)</u>

[6] Mr. Birk's Schedule MCB-D1 and Schedule MCB-D2 contain detailed lists of the many similar projects performed at Ameren facilities without NSR permits.

Q. Mr. Whitworth, were you aware of the 2010 projects at Rush Island Unit 2?

A. Yes.

Q. How did ESD receive notice of the upcoming projects on Rush Island Unit 2?

A. I recall first discussing the upcoming Rush Island Unit 2 projects with Ken Anderson, the head of the Air Quality Group, sometime in the 2008-2009 timeframe. I do not specifically recall how the Rush Island Unit 2 projects came to his attention, but I also know that the upcoming outage for Unit 2 and the general scope of work was published within the Company and widely known at the time. The generation department circulated the outage schedule well in advance, and the specific projects to be implemented were identified in planning and scheduling documents circulated by senior leadership and the project engineering group.

Q. In 2008, Ameren Missouri received a Section 114 inquiry from EPA about projects performed across its coal-fired fleet over the prior 20-plus years. Did that alter ESD's approach to the evaluation of the upcoming Rush Island Unit 2 Projects?

A. No. The process for ESD review of the Rush Island Unit 2 Projects was very similar to what occurred for Rush Island Unit 1.

I understand that Section 114 of the Clean Air Act gives EPA authority to request information from regulated parties for certain purposes. I further understand that at various times since 1999, EPA has used this authority to issue broad requests for data pertaining to past projects by electric utilities, which EPA has sometimes (but not always) turned into an ***allegation*** of NSR violations. But a request for information under Section 114 did not change the applicable regulations, the nature of the projects, the fact that they would not be expected to increase emissions, or the fact that all of the projects at issue were the kind routinely performed across the industry.

Q. What happened after the upcoming 2010 Rush Island Unit 2 Projects were brought to ESD's attention?

A. We talked internally within ESD, and assigned a member of the Air Quality Group staff to collect the necessary information and to start the necessary analysis.

Q. What happened next?

A. The Air Quality Group staff gathered the necessary information, including the scope of the work (i.e., the components at issue), the dates of outage, and the nature of the work to be performed. We verified that none of this work would change the primary design of the steam generating unit. We also assessed the operating characteristics of the unit and the expected post-project operations.

Q. What did ESD know about the upcoming Rush Island Unit 2 Projects after assembling this information?

A. We were made aware that Ameren Missouri was planning an outage at Rush Island Unit 2 that would begin in January 2010 and last until April of that year. We were advised that during this outage, a number of different maintenance, repair and replacement projects would take place, as is typical practice for a coal-fired electric utility unit. We were also made aware that the projects scheduled for this outage included replacements of the reheater, the economizer, and certain air preheater components, which I will refer to hereafter as the "Rush Island Unit 2 Projects." We were briefed on the nature and scope of the Rush Island Unit 2 Projects. We were advised that all of these projects were "like-kind" replacements, in that none of the replacements would change the function of any component or change the maximum hourly heat input capacity, the maximum hourly steam flow capacity, or the maximum hourly emissions rate.

ESD knew that the Rush Island Unit 2 Projects were similar to component replacement projects that had been performed over and over again across the Missouri and Illinois fleets supported by ESD. Throughout this time period, the same types of projects were brought over and over again to ESD for permitting review: boiler tube replacements (economizers, reheaters, superheaters, and waterwalls) and boiler auxiliary equipment repairs and replacements (air heaters, fans, pulverizers, pumps, etc.). I and others on the ESD staff had considerable knowledge and experience with assessing these types of projects, and recognized that they would not cause any increase in potential emissions or actual emissions.

Finally, we knew that the Rush Island Unit 2 Projects were much less extensive than the WEPCo Port Washington Project, where EPA had determined that the extensive rebuilding of five coal-fired units at successive nine-month outages, in order to increase the maximum achievable capacity, would trigger NSR.

Q. What did ESD consider in making its assessment of whether the Rush Island Unit 2 Projects required NSR permitting?

A. As was the case with Rush Island Unit 1, we applied our understanding of the law. That understanding began with the text of the Missouri SIP Construction Permitting Rule, 10 C.S.R. 10-6.060 (2006). We also relied upon MDNR's settled interpretation and application of the Construction Permitting Rule in the context of boiler component replacement projects. The Construction Permitting Rule incorporated by reference the federal NSR rules (both the PSD regulations and the NNSR regulations). We therefore considered the plain language of the federal NSR rules and how those rules had been described and applied by EPA, state regulators, and the electric utility industry over the years. These were the key sources that informed our understanding of the law at the time, which formed the starting point for ESD's analysis.

As I have previously noted, if legal questions arose during the process of ESD review of a particular project, ESD would consult with the Ameren Services Legal Department. In the pre-project evaluations performed by ESD for the Rush Island Unit 2 Projects, I do not recall asking the Legal Department to weigh in on whether the projects would trigger NSR applicability, because there was no reason to do so.

Q. In addition to your understanding of the applicable law in Missouri, what else did you consider in making your decision on whether the Rush Island Unit 2 Projects would trigger NSR permitting requirements?

A. Our evaluation of the Rush Island Unit 2 Projects considered the following, in addition to our understanding of the applicable law:

- The purpose, nature and scope of the projects;
- The similarity of these projects to countless other projects performed by Ameren Missouri, by its Illinois affiliate, and across the industry;
- Our knowledge of the role of demand in how much and when coal-fired electric generating units operate;
- Our knowledge of the historical operational characteristics, output, and capability of the units as published in internal company databases;
- Our experience with similar work on Ameren Missouri's and Illinois' units, and the pre- and post-outage emissions data for those units with which ESD works on a daily basis; and
- Our experience with performing emissions calculations for similar work on Illinois units, which showed that like-kind replacement of parts on existing units are not expected to cause any increase in actual annual emissions where, as here, the units had additional, untapped capacity to generate in the baseline period (i.e., in the absence of the proposed work) greater than any projected future annual operating level.

Q. What conclusion did ESD reach about the upcoming Rush Island Unit 2 Projects?

A. We concluded that the projects would not trigger any permitting requirements under the Missouri SIP, including any NSR permitting requirement. In reaching this conclusion, we considered the outage work as a whole.

Q. Why did ESD reach the conclusion that the upcoming Rush Island Unit 2 Projects would not trigger NSR permitting under the Missouri SIP?

A. We had three independent reasons for concluding that the Rush Island Unit 2 Projects would not trigger NSR under the Missouri SIP, any one of which standing alone would have excluded the projects from NSR review. First, the Missouri SIP as both MDNR and we understood it at the time required permitting for a project on an existing source (e.g., Rush Island Unit 2) only if the project would constitute a "modification," which the SIP defined as an increase in the potential emissions from the facility. Based upon the description of the projects I received, nothing that would be done in the outage would have increased the potential emissions of Unit 2. That meant to us that the projects were excluded from NSR permitting for that reason alone.

Second, we did not believe that the Rush Island Projects would cause actual annual emissions to increase. If a project does not cause actual annual emissions to increase, then it is not a "major modification" as defined in the federal NSR regulations incorporated into the Missouri SIP, and thus it would not require any NSR permit.

Third, we considered all the Rush Island Unit 2 Projects to be the "routine maintenance, repair and replacement" of parts, which is explicitly excluded from NSR permitting requirements regardless of any emissions the work might cause.

Q. What was the factual basis for the conclusion that the upcoming Rush Island Unit 2 Projects would not cause an increase in potential emissions?

A. Based upon the description of the projects provided, these "like-kind" replacement of components would not increase the unit's maximum heat input capacity (i.e., the amount of coal the boiler could burn), maximum steaming rate (i.e., the pounds per hour of steam produced by the boiler), or its maximum hourly emissions rate (i.e., the pounds per hour of pollutants emitted through the stack). In short, nothing would change the unit's maximum annual rated design capacity given continuous year-round operations. Based on our considerable experience with NSR applicability determinations under the Missouri SIP, the language of the SIP, and MDNR's stated interpretation of the SIP, we understand that such projects would not increase the unit's annual rate of potential emissions, and therefore did not constitute "modifications" under the Missouri SIP. Accordingly, we determined that the Rush Island Unit 2 Projects would not trigger the application of the Missouri Construction Permit Rule, meaning no construction permit was required.

Q. The megawatt rating of Unit 2 increased after the 2010 outage. Does that indicate that there was an increase in potential emissions?

A. No. The maximum hourly emissions rate was the same both before and after the 2010 outage—there was no increase in the maximum hourly fuel flow, the maximum hourly air flow, or the maximum hourly steaming rate. All these design parameters would remain the same, and in fact did remain the same. As a result, there was no increase in potential emissions.

It was quite clear from our prior experience that turbine upgrades like that at Rush Island Unit 2 in 2010 would lower emissions—not increase them—because the turbine would require less steam (and therefore less fuel) to produce the same level of electrical output. Before the low-pressure turbine upgrade performed on Unit 2 in 2010, ESD performed a study of the many similar turbine upgrades that had been done across the Missouri fleet and the Illinois fleet. The data showed that although these turbine upgrades increase the electrical output of the units, in no instance did they increase the hourly heat input of the unit—meaning that there was no increase in hourly emissions (and by extension, no increase in potential emissions).

Q. Were any calculations done to confirm that the upcoming Rush Island Unit 2 Projects would not increase the potential emissions of the unit?

A. No. I previously explained, in the context of addressing the Rush Island Unit 1 Projects, why none were required. Those same reasons apply here: in our engineering judgment, it was obvious that the like-kind replacements would not cause potential emissions to increase, and the regulations did not require this sound engineering judgment to be supplemented by some mathematical proof.

Q. You mentioned that ESD also considered changes in actual annual emissions. If ESD had already determined that the Rush Island Unit 2 Projects would not increase potential emissions, then why did it also consider actual annual emissions?

A. As I have already explained in the context of Rush Island Unit 1, an analysis of changes in actual annual emissions was not required. But at the same time, we (ESD) understood that projects like these, on well-maintained units like Rush Island, are not expected to cause actual annual emissions to increase. This knowledge and experience was simply part of the engineering judgment that we brought to every NSR assessment, regardless of the applicable regulations.

Q. What were your conclusions regarding actual annual emissions?

A. We did not believe that the Rush Island Unit 2 projects would cause Unit 2 to operate more in the future, and thus there would not be any increase in actual annual emissions caused by the Rush Island Unit 2 Projects.

Q. Why didn't you believe the projects would cause actual emissions to increase?

A. As I have noted, ESD had experience with and knowledge of many similar projects performed on the Ameren Missouri system and in Illinois in the years prior to the Rush Island Projects. Because ESD also has the job of tracking and reporting annual emissions from all of these plants, ESD was familiar with the emissions profile before and after similar projects were completed. In our considerable experience, changes in annual emissions are primarily caused by changes in emissions factors (i.e., fuel sulfur content, pollution control equipment, efficiency) or demand. In our experience, projects like those done at Rush Island do not cause actual annual emissions to increase.

A significant part of the collective ESD experience that informed this understanding were the emissions calculations that ESD was performing at that time for projects in Illinois to determine whether the federal NSR rules directly applicable in that delegated state would require permitting for any of the Illinois projects. In performing those calculations, ESD would first select the baseline annual emissions, from the emissions data for each unit that we worked with on a daily basis. As a second step in performing those calculations, we would project the annual emissions following the project for the Illinois unit in question. One significant input to that projection would be the projected annual operations provided by the system planning department, which modeled how each unit on the system was expected to run in the future. As a third step, ESD would compare the baseline annual emissions to the projected annual emissions for the Illinois unit in question, to determine whether there would be an increase expected in annual emissions. If there was such an increase expected, then ESD would proceed to the fourth step—determining whether the project would be the cause of the projected increase in annual emissions. ESD would do so by examining operations of the Illinois unit in the baseline period, and seeing what the annual emissions could have been prior to the project. If the unit could have accommodated the projected future operations in the baseline period (i.e., before the work at issue is done on the unit), then the logical conclusion is that any projected increase would have to be due to demand growth or other independent factors – not by the work at issue in the outage – and therefore the work would not be expected to result in a projected increase in emissions.

After performing similar analyses in Illinois over and over again, applying the federal NSR rules, a consistent pattern emerged. Where a unit has good availability, with additional (but unused) capacity to generate in the baseline period, the like-kind replacement of components as they wear will not cause annual emissions to increase. That understanding was consistent with the experience of other utilities across the country, as I learned in my participation in UARG meetings.

Here, we were aware that Rush Island Unit 2 had good availability and additional (unused) capacity to generate in the baseline period prior to the projects. Based upon our experience with applying the federal NSR rules in Illinois, and the experience of similar utilities across the country, there was no reason to expect that the Rush Island projects would cause annual emissions to increase. Rather, the ongoing demand growth that Ameren Missouri was experiencing in this timeframe would be the predominant cause of any increase in hours of operation or production rate of Rush Island Unit 2, and thus the predominant cause of any future actual annual emissions increase.

Because we did not expect that the Rush Island Projects would cause actual annual emissions to increase, we did not believe that the projects would be a "major modification" under the federal NSR rules incorporated into the Missouri SIP.

Q. What was the factual basis for ESD's conclusions that the upcoming Rush Island Unit 2 Projects were routine?

A. Under the federal PSD rules incorporated into the Missouri SIP, permitting is required only for a "physical change or change in the method of operation" of a unit that would result in a significant net emissions increase. These rules exclude "routine maintenance, repair and replacement" from the definition of "physical change or change in the method of operation." Thus, maintenance, repair and replacement activities do not require NSR permits—regardless of any emissions impact—if those activities are "routine."

The replacement of these boiler components and auxiliary equipment components at Rush Island Unit 2 are clearly "replacement" and "repair" activities. Moreover, these "replacement" and "repair" activities are commonly understood to be routine. ESD understood, from our conversations with the engineering personnel, that the projects at issue were like-kind replacement of existing components with new components that would be functionally equivalent. ESD and project engineering were in alignment that such replacements were commonly performed throughout the industry, and we had personal knowledge of dozens of similar component replacements performed on the Ameren Missouri system and the Illinois units in the years leading up to the Rush Island Projects. We had replaced economizers, reheaters, and waterwalls multiple times at Labadie, Meramec and Sioux. We had replaced air preheater components multiple times at the same plants, and at Rush Island as well. We were also aware that other utilities regularly performed similar component replacement projects. This understanding was developed through our interactions with other utilities, including through UARG meetings.

On the basis of these facts, I and my colleagues in ESD determined that the Rush Island Projects constituted "routine maintenance, repair, and replacement" activities that are excluded from NSR permitting under the Missouri SIP.

Q. Did ESD document these conclusions?

A. Not formally, because doing so was not required under the Missouri SIP as it existed at the time.

Q. What happened after ESD concluded that the Rush Island Unit 2 Projects would not trigger NSR?

A. ESD reported out the results of its evaluation, and Ameren Missouri proceeded with the projects. Although EPA later alleged that Ameren Missouri had violated NSR at other units, that allegation arose after the Unit 2 outage had commenced. EPA's allegations thus did not factor into ESD's pre-project applicability determination.

C. <u>Summary of ESD's Conclusions on the Rush Island Projects</u>

Q. If ESD did not document its determination that a project would not trigger NSR, then how do we know that ESD in fact reviewed the Rush Island Projects for NSR applicability?

A. As I have testified, this was part of the project planning process and I was personally involved. Planning for the Rush Island Projects began in 2005—two years before the 2007 Unit 1 outage and five years before the Unit 2 outage. The outage schedules and the scope of work to be performed within the outages were well known within Ameren Missouri and within Ameren Services. Contemporaneous documentation, in the form of internal emails attached as Schedule SCW-D21, confirms ESD had knowledge of the 2010 projects and had concluded that they did not trigger NSR. Although I do not have similar emails from 2005-2006 confirming that ESD was aware of the Rush Island Unit 1 Projects and had performed an NSR screening for them, I can recall working on this evaluation.

Q. Was there any part of the decision-making by ESD and Ameren Missouri regarding the Rush Island Projects that did not follow standard processes?

A. No. The projects were identified, evaluated and approved according to Ameren Missouri's procedures as they existed at the time. Although an employee of ESD (Michael Hutcheson) did a supplemental analysis for Rush Island Unit 2 after the fact, in the form of an emission calculation, this was a direct response to EPA's allegations of NSR violations and not part of the pre-project evaluation as it existed at the time. The fact that Mr. Hutcheson performed his calculation under the direction of attorneys and identified it as "work product" before later releasing it for use at trial demonstrates that Mr. Hutcheson's calculations were not part of the normal pre-project evaluation process that existed at the time.

Q. Did ESD present the Rush Island Projects to any regulators, and ask them to confirm ESD's conclusions?

A. No, because that was not part of the normal decision-making process. Both the Missouri SIP and the federal NSR regulations require regulated parties to make applicability determinations on their own, and do not require pre-approval from any regulatory authority. Although the opportunity exists to seek regulatory input in case of a "close call," we viewed it as clear-cut that the Rush Island Projects did not trigger NSR.

Q. Why?

A. We were relying upon 1) the plain meaning of the regulations; 2) MDNR's prior application of these regulations; 3) EPA's official statements concerning the NSR regulations, and 4) the shared understanding that Ameren Missouri had with the rest of the electric utility industry on the scope of NSR. Despite the fact that similar projects were done elsewhere in Missouri and across the country, none of us sought NSR permits. Moreover, as a general rule these utilities did not seek confirmation of non-applicability before undertaking these projects. Instead, the general practice for electric utilities (including Ameren Missouri) was to make the required pre-project determinations, then proceed with the necessary maintenance activities.

Subsequent events confirmed that Ameren Missouri correctly understood that its understanding of NSR aligned with that of MDNR. These include (1) the fact that MDNR inspectors observed the Rush Island Projects in progress, and did not raise NSR concerns, (2) guidance published by MDNR confirming that permits are required only for increases in potential emissions, (3) MDNR's refusal to join EPA's allegations of NSR violations by Ameren Missouri, and (4) the deposition testimony given by Kyra Moore, which I witnessed.

Q. The UARG documents you cite above make clear that ESD was aware of EPA's electric utility enforcement initiative at the time it was evaluating these projects. Did the existence of that enforcement initiative undermine ESD's conclusions that the Rush Island Projects did not trigger NSR?

A. No.

Q. Why not?

A. There were several reasons why EPA's enforcement initiative did not shake our conclusions that the Rush Island Projects would not trigger NSR. First, EPA itself was conflicted over the enforcement initiative. The program office had rejected the enforcement initiative interpretations by 2003 and paused the enforcement initiative for the remainder of the Bush Administration. Second, utilities were winning these cases more often than losing them. Third, ESD was applying the Missouri regulations in the EPA-approved SIP in making its determinations, and no other case involved these regulations. Under the Missouri SIP, as I have explained, no permitting was required because none of the projects would cause potential emissions to increase.

Fourth, our understanding of the projects targeted by EPA was that they generally involved units in poor working order, whose availabilities had substantially degraded and which required substantial work in order to achieve higher capacity factors. At Rush Island, however, the units were in good working order—with availabilities regularly over 90%—and neither unit needed component replacements in order to increase its capacity factor. Thus, even if there was to be some marginal increase in annual unit availability following the Rush Island Projects—and the plant managers involved in the work did not expect that to occur—we did not believe that this would cause a unit to increase its annual emissions. Unless there is some change in fuel or some change in the heat input capacity of the unit, changes in annual emissions are understood to be primarily a function of demand. This is particularly true for units that had untapped capability to generate prior to the outage at issue, and were capable of accommodating any projected increase in annual emissions even before the work is performed. That was the case with the Rush Island Units.

Finally, many of the cases in the enforcement initiative found that "routine maintenance, repair or replacement" means what is routine ***for the utility industry***. All of our projects on the

Rush Island units met that standard, as evidenced by the frequency with which such component replacements occur at Ameren Missouri, at its Illinois affiliates, and across the industry.

VIII. SUBSEQUENT CONFIRMATION OF ESD'S DETERMINATIONS

Q. From the time that ESD made its initial determinations that the Rush Island Projects would not trigger NSR permitting, until you received the results of the District Court litigation finding Ameren Missouri liable for violating NSR, did anything cause you to question whether ESD had reached the right conclusion?

A. No. We were surprised and disappointed by the District Court decisions.

Q. If Ameren Missouri was confident in its conclusions that the Rush Island Projects did not trigger NSR, then why did it evaluate the possible retrofit of scrubbers on Rush Island in 2007-2010?

A. Ameren Missouri evaluated the potential retrofit of scrubbers on all of its plants during this time period—not just Rush Island—as a direct result of other CAA programs for which EPA was promulgating rules. This was a process in which I was directly involved. The process began in 2004, with EPA's release of a proposed rule to reduce emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx). This rule became known as the Clean Air Interstate Rule ("CAIR"), which was promulgated in 2007. This rule was challenged, found to be unlawful by the courts in 2008, and replaced with another rule in 2010 (the Cross-State Air Pollution Rule or "CSAPR"), which was itself challenged. EPA also had a series of regulations concerning mercury and other hazardous air pollutants emitted from the combustion of coal—the Clean Air Mercury Rule ("CAMR") and the Mercury and Air Toxics Standards ("MATS") that also came out in this timeframe and were challenged in the courts. As a result, it was highly uncertain, for a number of years, what would be required from Ameren Missouri in terms of lowering emissions. Ameren Missouri continued to study the possibility of installing scrubbers on different plants at different times in order to hedge against the possibility that CAIR/CSAPR could turn out to be more stringent than proposed. But in every instance, the primary consideration in these studies was compliance with these new rules that EPA was promulgating—not NSR, because we did not find NSR applied. The resulting Environmental Compliance Plan found that scrubbers would not be needed beyond Sioux in order to achieve compliance.

Q. In all the analysis Ameren Missouri and its consultants did to develop the Environmental Compliance Plan for these new EPA rules, did the topic of NSR ever come up?

A. Yes. Because we were generally aware of EPA's (largely unsuccessful) NSR enforcement initiative against electric utilities, we considered NSR as one of a number of sensitivities in determining what was the right compliance plan for the Ameren Missouri system. See Schedule SCW-D22 (Aug. 2007 Agenda). In other words, the question was asked: once the compliance plan is established, how would it fare if NSR requirements later came into play? But at no point did Ameren Missouri or any of its consultants conclude that any project had triggered NSR (and would therefore require addition of additional controls). At the end of the day, the only applicable requirements we identified for inclusion in the Environmental Compliance Plan were those promulgated in the mid- to late-2000's: CAIR, CSAPR, CAMR and MATS. Because these were the only applicable requirements, they could be met without additional scrubbers being placed on the Ameren Missouri system, and installing additional, unnecessary controls would not be in customers' best interest, the Environmental Compliance Plan did not include additional SO2 controls on any plant (beyond the scrubbers at Sioux).

Q. Did Ameren Missouri ever re-visit its pre-project determinations that the Rush Island Projects would not trigger NSR?

A. Yes. Ameren Missouri re-visited the potential application of NSR in 2008, following the receipt of an inquiry from EPA under Section 114 of the CAA, concerning a large number of maintenance, repair and replacement projects. And Ameren Missouri revisited the potential application of NSR again in 2010, after receipt of the Notice of Violation ("NOV") issued by EPA that January.

Q. What was the result of those subsequent evaluations?

A. Ameren Missouri remained firm in its conclusion that the Rush Island Projects did not trigger NSR. As a result, Ameren Missouri's Environmental Compliance Plan continued to focus on the new rules EPA was promulgating: CAIR, CSAPR, CAMR and MATS.

Q. Did the allegations of non-compliance in the January 2010 NOV alter your conclusions about NSR applicability?

A. No. Although EPA made allegations in its NOV that several projects were NSR violations, it did not explain how or why it believed that any of the projects increased emissions so as to trigger NSR. EPA refused to share its position on emissions increase with Ameren Missouri, and Ameren Missouri was not able to learn how EPA purported to calculate emissions until discovery occurred following commencement of the litigation. EPA did share enough for Ameren Missouri to understand that its allegations of emissions increase were not based on potential emissions, but on changes in actual annual emissions. Although we remained comfortable that only an increase in potential emissions would trigger NSR under the applicable law, an employee of ESD was directed by the Legal Department to prepare a calculation assuming that the actual annual emissions increase test was the required approach. (Ameren Missouri presented the resulting calculations for Unit 2, performed by Michael Hutcheson, at trial.) Even when this was done, however, it showed that the projects would not be expected to cause annual emissions to increase, because the units were capable of achieving the projected future annual emissions before the projects were done. We therefore continued to believe that EPA's allegations were without basis in law or fact.[7]

Q. What did Ameren Missouri know about the status of EPA's NSR enforcement initiative at the time that Ameren Missouri received the NOV in January 2010 and prepared its emissions calculations?

A. Ameren Missouri received briefings from UARG summarizing the NSR enforcement initiative. These briefings confirmed that similarly situated utilities had performed similar work and made the same decisions that we did: the work could proceed without NSR permitting. For example, Westar Energy had been sued in the District of Kansas for performing economizer and reheater replacements at its Jeffrey Energy Center without obtaining NSR permits, and was actively contesting those allegations. Schedule SCW-D10; Schedule SCW-D11. The briefings UARG obtained from counsel, which I have summarized above and attached here, informed us how EPA itself was conflicted over the proper application of NSR, see Schedule SCW-D3 and Schedule SCW-D5, and that EPA's litigation position in the NSR enforcement initiative failed more often than not. Schedule SCW-D10 through Schedule SCW-D18.

[7] We were both surprised and disappointed when the District Court subsequently rejected Mr. Hutcheson's post-project calculations in its liability decision, because Mr. Hutcheson performed these calculations consistently with what ESD understood EPA's position to be.

Q. Did you believe the controls demanded by EPA in the NOV were required under the law as you understood and applied it in Missouri at the time?

A. No. They were not required under the Missouri SIP, and were not anticipated to be required by CAIR, CSAPR, CAMR or MATS.

Q. Did you anticipate that EPA would prevail on any of its claims against Ameren Missouri alleging NSR violations?

A. I am not a lawyer, so I would defer to experts such as Mr. Holmstead and Mr. Moor for assessment of the strength or weakness of any NSR claim. However, I can say that based upon what I knew about the legal requirements, what I knew about EPA's inconsistent positions on NSR, what I knew about the difficulties EPA's litigation theories encountered in the enforcement initiative, and what I knew about Ameren Missouri's evaluation of the projects for NSR applicability, I did not anticipate that EPA would prevail on the claims it brought under the NOV. I was therefore surprised and disappointed when the District Court rejected MDNR's (and our) understanding of the law and instead applied an entirely different standard to hold Ameren Missouri liable.

Q. Were the controls demanded by EPA under its NOVs to Ameren Missouri consistent with Ameren Missouri's Environmental Compliance Plan as it existed in 2010-2011?

A. No. The Environmental Compliance Plan called for scrubbers (to control SO2) only for the two Sioux units. After that, it was anticipated that low-sulfur coal and emissions allowances would allow the Ameren Missouri system to comply with all the SO2 requirements being promulgated by EPA.

Q. Did your work with UARG on behalf of Ameren give you insight to how other utilities responded to allegations of non-compliance in an EPA NOV?

A. Yes.

Q. Did Ameren Missouri respond to the NOV differently from how the majority of similarly situated utilities responded in the EPA enforcement initiative, as you understood it from the UARG briefings you received?

A. No. My understanding is that where the controls sought by EPA in its consent decrees were inconsistent with the targeted utility's business plan, the utility generally contested the NSR allegations rather than settle an NOV. Schedule SCW-D4, Schedule SCW-D10.

***

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Petition of Union Electric Company d/b/a Ameren Missouri for a Financing Order Authorizing the Issue of Securitized Utility Tariff Bonds for Energy Transition Costs related to Rush Island Energy Center.	))))))	EF-2024-0021

AFFIDAVIT OF STEVEN C. WHITWORTH

STATE OF MISSOURI)
) **ss**
CITY OF ST. LOUIS)

Steven Whitworth, being first duly sworn on his oath, states:

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

Steven C. Whitworth

Subscribed and sworn to before me this 11th day of November, 2023.

Notary Public

My commission expires: 5/10/27

ERIN KEENOY
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis City
My Commission Expires: May 10, 2027
Commission Number: 23459735

Appendix A - Environmental Compliance Planning Process at AmerenUE

DRAFT 3/6/08

The process for developing a preferred plan for compliance with environmental regulations for AmerenUE involves a number of divisions within AmerenUE and Ameren Services. In developing a compliance plan for a regulation which will require significant financial and/or labor resources, preliminary planning begins at a very early stage - usually well before the regulation is promulgated. This allows the company to begin assessing various compliance options, conduct research into technologies, collect preliminary monitoring data, possibly conduct pilot projects, and begin planning for potential future financial, labor, technical and consulting needs.

It is important to note that throughout the planning process, the primary divisions identified below are in constant contact and communication. Early on, each division identifies the individuals with the expertise needed to be involved to address the particular regulatory, technical, and financial requirements of the subject regulation. Frequent meetings, correspondence and daily conversations allows each division to stay apprised of any new information, developments or changing circumstances which could influence a preferred strategic approach.

The following is a very brief synopsis of the responsibilities of the primary departments involved in the environmental compliance planning process. A more detailed description of each department's activities in the process is provided below.

The Environmental Services Department is responsible for defining the regulatory requirements. Power Operations Services is responsible for identifying pollution control technologies and costs. The Ameren Fuels and Services group provides fuel options, costs and characteristics. The Treasury/Finance group evaluates cost impacts relative to overall AmerenUE cash flow and integration with other capital and O&M requirements. Corporate Planning assimilates and analyzes the information from all these groups to develop compliance options. AmerenUE management reviews and refines these options, and makes the decision on a preferred approach, often keeping the flexibility to adjust the plan as conditions and requirements change. Finally, the Executive Leadership Team endorses the plan.

Environmental Services Department (Ameren Services)

The process of developing a compliance plan to meet new environmental regulatory requirements begins with the Environmental Services Department (ESD). Environmental Services uses a number of information sources to keep apprised of potential and developing environmental regulations and legislation. At both a national and state level, Ameren is a member of a number of industry organizations and regulatory groups which focus solely on environmental legislation and regulations facing the electric utility industry. Environmental Services' staff works with these industry groups and directly with local, state and federal environmental regulators to keep abreast of and influence new and developing environmental requirements.

At the earliest indication that a developing environmental regulatory program could potentially effect AmerenUE's operations, Environmental Services issues a summary of the pending requirements for compliance, such as emission targets and timetables. This summary is provided to AmerenUE and Ameren Services management who will become affected by, or be part of, the planning and/or implementation of the compliance strategy. Working groups are established with individuals from each department for this purpose. In the case of an obvious major regulation, such as the Clean Air Interstate Rule, teams are assembled and working to evaluate numerous compliance options long before the final rule is issued.

ESD is also responsible for collecting and reporting compliance data from the AmerenUE operating departments, such as stack emissions and water quality data. As such, ESD is the source of the environmental data used in developing baseline information on emissions and tracking emission credits, which form the basis for determining the degree of emissions control or monitoring systems required.

Power Operations Services (AmerenUE)

Power Operations Services (POS) provide project management, quality control, and environmental systems management for AmerenUE. From an environmental compliance planning perspective, POS has several major functions. These include, identification of pollution control and monitoring technologies and associated costs, assessing the resources needed to operate such systems, assessing the feasibility of various pollution control options for individual generating units, conducting research and pilot studies of emission control measures, and installation of the pollution control and monitoring systems.

Once emission control and monitoring requirements have been identified, POS begins the process of researching and evaluating various hardware options, vendors and suppliers of pollution control and monitoring equipment that can satisfy the regulatory requirements. Often, POS will use external consulting services (such as A&E firms with broad experience in pollution control) to assist in the identification of pollution control options and costs. POS also works closely with the Electric Power Research Institute (EPRI), universities and other consortiums to keep abreast and help foster the development of commercial technologies that hold the promise of cost-effective emission controls. Through their expertise on technologies, and their knowledge of site specific generating unit designs in the AmerenUE system, POS develops a number of options for meeting the emission control requirements. With the help of outside resources and current industry data, costs are estimated for each technology option.

The POS group also works with AmerenUE generation management to determine power supply needs and outage schedules, to develop recommendations on the timing of the installation of control equipment.

Ameren Fuels and Services (Ameren Services)

The Ameren Fuels and Services (AFS) function continuously monitors supply options and costs for coal, gas, oil, and alternative fuels. AFS works with AmerenUE to procure these fuel supplies consistent with meeting environmental regulations and operating requirements. AFS works closely with Power Operations Services to ensure technology options under consideration in the environmental compliance planning are feasible with the fuel supply. For instance, dry scrubbing technology for SO2 removal prohibits the ability to use moderate to high sulfur coals, which could prevent AmerenUE from using lower cost fuel supplies in the future if dry scrubbing technology is installed on a particular unit.

AFS also monitors the market for emission credits, and executes the contracts for the trading and transfer of emission allowances.

AFS is also responsible for contracting renewable generation.

Treasury/Finance (Ameren Services)

Business Planning and Controllers (AmerenUE)

These finance groups are involved in the environmental compliance planning process by evaluating the cost impacts of compliance options relative to overall AmerenUE cash flow and how the timing of expenditures can be integrated with other capital and O&M requirements. While deadlines for compliance are established by regulation, the timing of major capital expenditures may be constrained by the ability to finance such projects relative to other monies necessary to provide a continuous and reliable source of electricity and gas to customers.

These departments also review the total cost of compliance to ensure budgets are reconciled to the future operating requirements and develop financial disclosures consistent with expected expenditures.

Corporate Planning (Ameren Services)

The analysis underlying the environmental compliance planning process is performed by Corporate Planning. Information from all of the above departments is assimilated for analysis. Additional information from other groups within Corporate Planning, AmerenUE, and outside sources may be utilized and could include data such as forecasted heat input for each generating unit and SO2, NOx and Hg allowance price forecasts. Ameren's corporate Economic Value Added (EVA) Model is frequently used to determine least cost compliance options through the minimization of the present value of revenue requirements.

Corporate Planning compiles all the underlying assumptions, planning information and the results of their analyses into presentations, reports or spreadsheets that describe various compliance options. These materials are presented to AmerenUE management and the Executive Leadership Team.

AmerenUE Management

The compliance options are presented to the senior management of the affected AmerenUE operating group, and the senior management of AmerenUE. This sometimes leads to further refinement and the examination of additional options. AmerenUE management ultimately determines the preferred compliance option. Since market conditions, materials supply, emission allowance prices, regulatory actions and other industry or company actions may materially change over the course of the planning process, contingencies and alternatives are usually considered. However, once the plan begins to be implemented, such contingencies and alternatives become limited.

Executive Leadership Team

For major compliance plans, such as for the Clean Air Interstate Rule, presentations are made to the Executive Leadership Team at several stages in the process. Since all divisions of the company are represented by the ELT, these meetings provide an opportunity to ensure all factors are being considered and all the appropriate resources are being used in the plan development. Once AmerenUE management determines the preferred compliance plan, it is reviewed by the ELT, to ensure consistency with Corporate goals and objectives. Once any concerns raised by the ELT have been addressed, the ELT endorses the compliance plan, and it is put into action.

Planning Process Coordination

The overall planning process is coordinated by senior management, usually at the ELT level. The Vice President of Environmental Services, Corporate Planning and AmerenUE meet periodically to ensure the planning is progressing properly. The staffs of the primary departments meet on a continuous basis, from the early stages until a preferred plan has been developed. Additional company resources are used as necessary, such as personnel from the Legal Department, Risk Management, Government Affairs, and Corporate Communications, to ensure the process considers all relevant information, and all appropriate departments are engaged in the process.

Environmental compliance planning at AmerenUE is a dynamic and robust process. AmerenUE management uses the experience of both internal and external resources to develop a plan that ensures the company will meet regulatory requirements with a compliance margin. By using this expertise, the planning process ensures AmerenUE will not only maintain compliance with new and existing regulations, but also considers likely environmental and operating constraints that will face the company in the future. Ultimately, compliance plans meet the corporate goal of environmental stewardship, demonstrates environmental leadership though innovative solutions and technologies where possible, provides a compliance margin to allow for operating contingencies, and are developed to be as cost-effective as possible. In meeting these criteria, the plan is designed to protect the company's ratepayers and shareholders.

EF-2024-0021

Schedules SCW D2-D19 are Confidential in their Entirety

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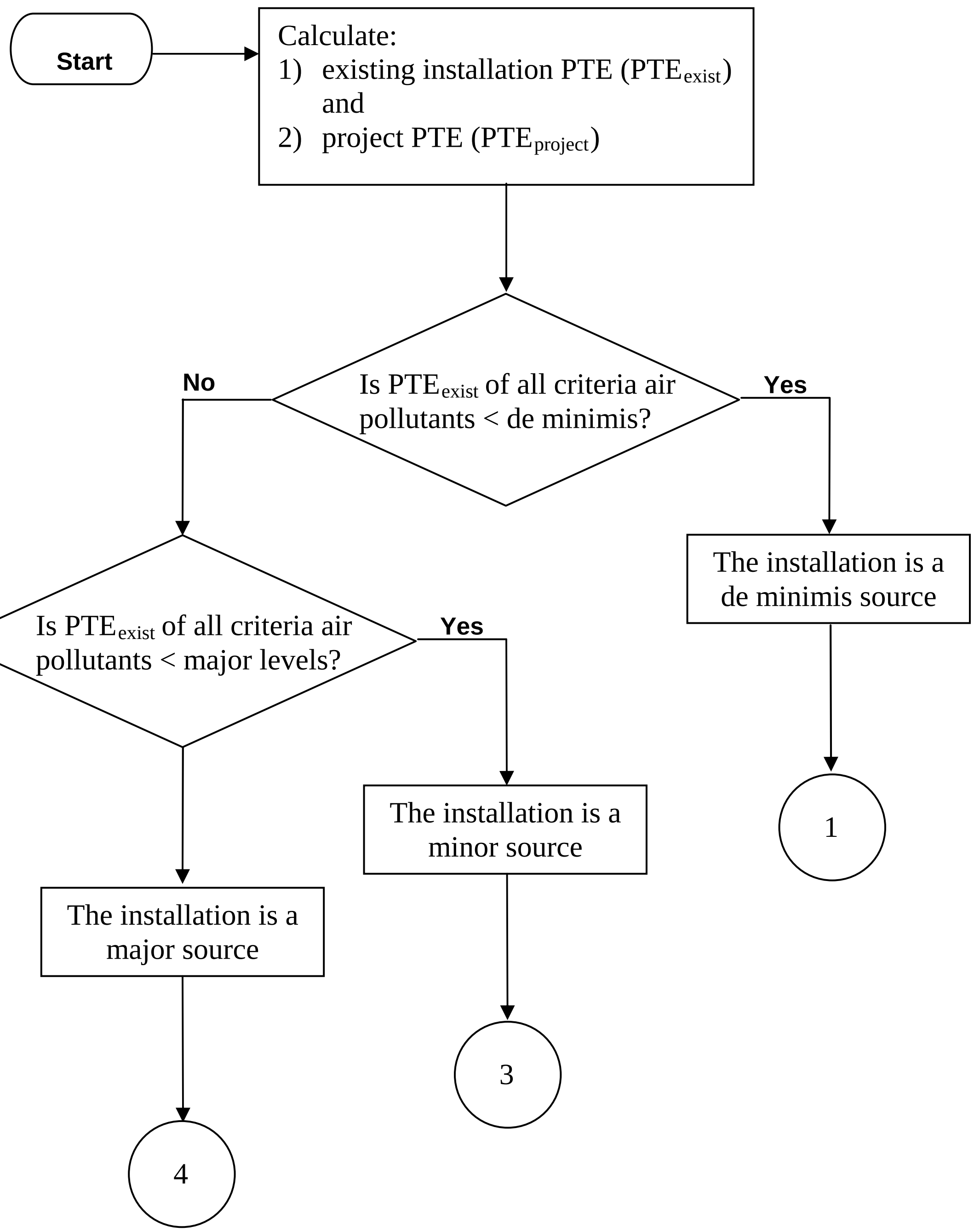
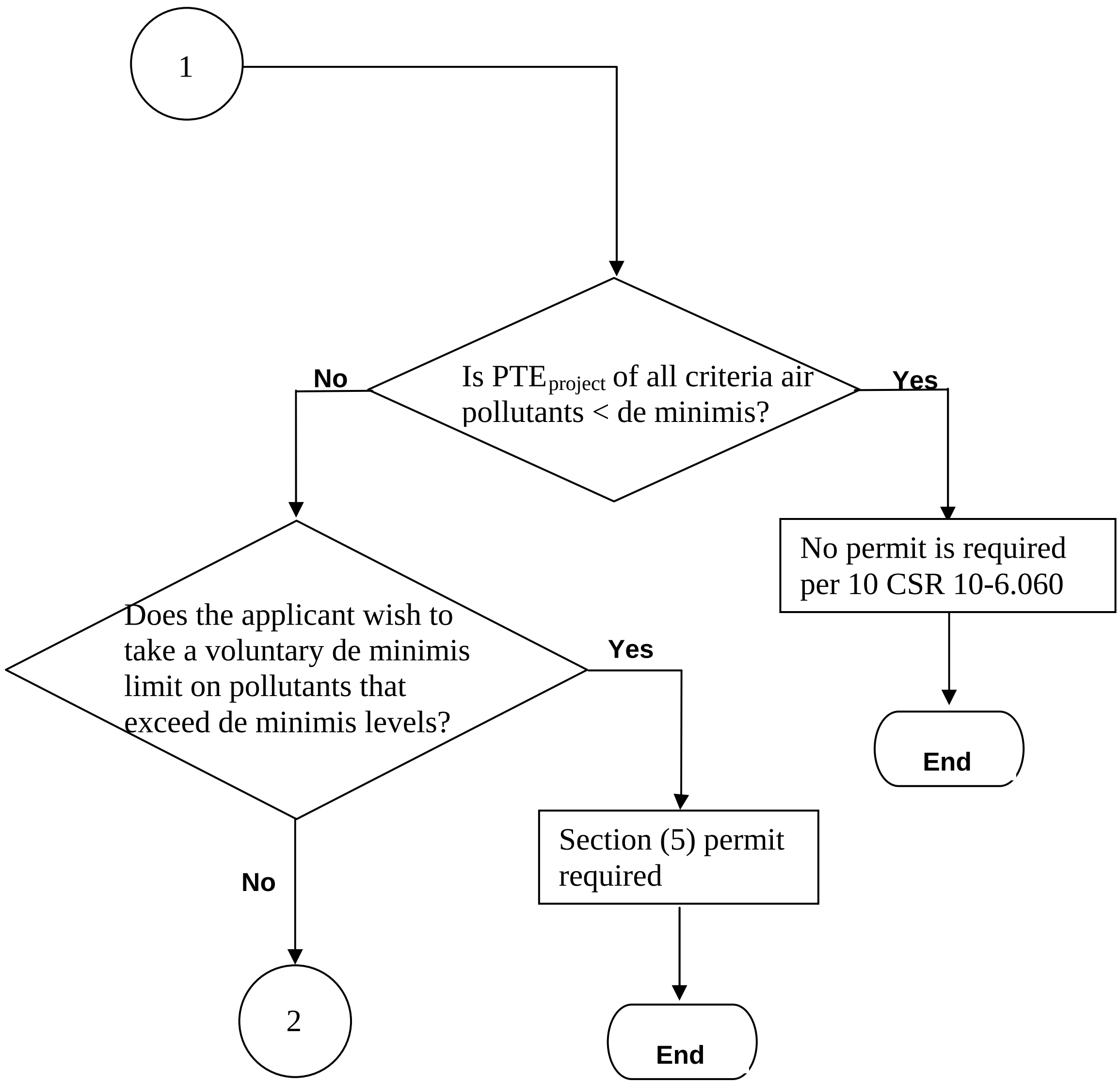
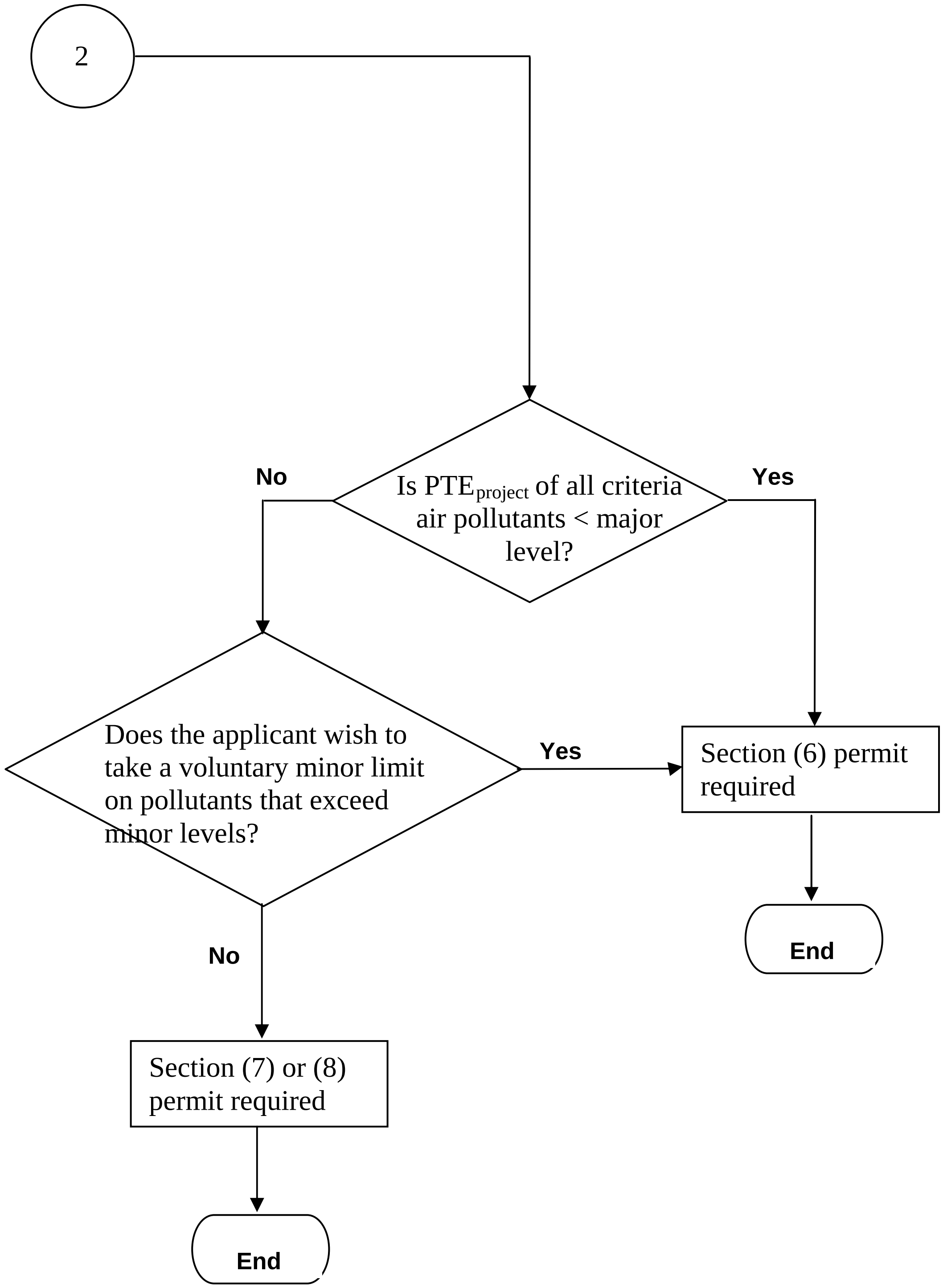
Permit Applicability Determination for Criteria Air Pollutants (1 of 6)



Schedule SCW-D20



Schedule SCW-D20



Schedule SCW-D20

From:	Whitworth, Steve C <SWhitworth@ameren.com>
Sent:	Thursday, January 14, 2010 2:38 PM
To:	Anderson, Kenneth J <KAnderson@ameren.com>; Menne, Michael L <MMenne@ameren.com>
Subject:	Re: GHG PSD analysis

Need to add FGD at Rush Island and Labadie. Meramec is a repowering study and not necessarily FGD. Do we include Joppa (FGD). There are also possible future boiler projects on Newton 2 and Coffeen units.

Sent from my BlackBerry Wireless Device

From: Anderson, Kenneth J
To: Menne, Michael L
Cc: Whitworth, Steve C
Sent: Thu Jan 14 08:57:22 2010
Subject: RE: GHG PSD analysis

Mike,

Kevin is about ½ way done with the coal plants. He expects to be finished with the coal plants by next Tuesday. Is that soon enough? We can accelerate this if needed.

I will have to contact some folks in generation projects to what is being planned if you need details. Projects I am aware of

1) Newton FGD
2) Ue landfill gas project
3) FGD study at Meramec
4) Coffeen Unit 2 HPIP
5) Rush Unit2 replacement of RH, Surge bin, A&B air preheaters

We don't believe any of these projects would be PSD under normal circumstances, but we have not done a CO2 analysis. But expect any increase in utilization to be under "capable of accommodating" i.e. load growth. Steve W. may have other info.

Ken Anderson
314-554-2089
kjanderson@ameren.com

From: Menne, Michael L
Sent: Wednesday, January 13, 2010 4:51 PM
To: Anderson, Kenneth J
Cc: Whitworth, Steve C
Subject: GHG PSD analysis

Any progress? Schukar called to say he is looking for info to give to Artman so they can put it into their climate analysis.

Along the same lines, it would be good to know what projects are coming up at any of the power plants that might trigger a GHG or PSD review. Can we put some kind of list together?

Schedule SCW-D21

AmerenUE Environmental Compliance Strategy Analysis
Open Items – August 9, 2007

- Analyze the case of burning Illinois basin coal at RI.
- Quantify the co-benefits of WFGD, DFGD & SCR for Hg capture.
- Define capital and O&M costs and unit operating and emission characteristics of WFGD and DFGD for the three fueling options: LS PRB, HS PRB & Illinois Basin coals.
- Quantify Hg control costs for the three fueling options.
- Quantify impact of Illinois basin coal on NOx rates.
- Quantify limitation on availability of HS PRB (Jacob's Ranch) coal.
- Can we blend HS PRB coal with LS PRB coal?
- Can we blend PRB coal with Illinois basin coal?
- Analyze sensitivities, such as:
    - Retire Meramec Plant in 2021
    - Capital and operating costs
    - Removal efficiencies
    - Allowance prices
    - Alternative fueling assumptions
    - New coal unit
    - Improved NO_x removal at existing plants
    - New Source Review

Schedule SCW-D22