BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Supplemental Petition of
Salt River Project Agricultural Improvement and Power District for Partial Reconsideration and Stay of EPA’s Final Rule: “Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans”


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SUPPLEMENTAL PETITION OF
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT
FOR PARTIAL RECONSIDERATION AND STAY OF EPA’S FINAL RULE:
“APPROVAL, DISAPPROVAL AND PROMULGATION OF AIR QUALITY IMPLEMENTATION PLANS;
ARIZONA; REGIONAL HAZE STATE AND FEDERAL IMPLEMENTATION PLANS”


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This document supplements the petition submitted to EPA on February 4, 2013, by Salt River Project Agricultural Improvement and Power District ("SRP")1 seeking the partial reconsideration and stay of the United States Environmental Protection Agency ("EPA" or “Agency”) final rule, “Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans,” as it applies to the Coronado Generating Station ("Coronado"). 77 Fed. Reg. 72,512 (Dec. 5, 2012) (“Final Rule” or “rule”). In that petition, SRP requested reconsideration of the Final Rule’s best available retrofit technology ("BART") requirements for emissions of nitrogen oxides (“NOx”) at Coronado and the provisions of the rule that require use of the plantwide 30-boiler-operating-day convention specified in the rule. The 2013 Reconsideration Petition also included requests, made pursuant to the Administrative Procedure Act (“APA”) and the Clean Air Act (“CAA” or “the Act”), that EPA stay the effectiveness of, and toll the compliance period for, the Final Rule’s NOx BART requirements applicable to Coronado pending completion of the Agency’s

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1 Petition of Salt River Project Agricultural Improvement and Power District for Partial Reconsideration and Stay (Feb. 4, 2013) (“2013 Reconsideration Petition”). The 2013 Reconsideration Petition is attached hereto as Attachment A-1 (attached to the Declaration of James M. Pratt (which is Attachment A hereto)).
deliberations on reconsideration and completion of pending litigation seeking review of the Final Rule in the U.S. Court of Appeals for the Ninth Circuit.\(^2\)

In a letter dated April 9, 2013, EPA granted reconsideration of the plantwide NOx BART emission limit and the NOx BART compliance methodology for Coronado. That letter opened a dialogue between SRP and EPA, but EPA has not yet formally convened the reconsideration proceedings or acted on SRP’s request for an administrative stay of the Final Rule or any other element of the petition.

As discussed below, developments since the filing of SRP’s 2013 Reconsideration Petition provide new and previously unforeseeable grounds for a stay of the Final Rule and EPA’s reconsideration of the BART FIP for Coronado. In particular, EPA’s planned carbon dioxide (“CO\(_2\)”) performance standards for existing coal- and natural gas-fired electric generating units, as described in the Agency’s proposed rule published on June 18, 2014, 79 Fed. Reg. 34,830 (“111(d) Proposal”), will likely require Coronado to cease operations in 2020. The publication and pendency of the 111(d) Proposal create enormous uncertainty regarding the future viability of Coronado and whether installation of costly new emission controls to satisfy BART requirements, such as those imposed by the Final Rule, would be reasonable or economically feasible. For those reasons, SRP hereby submits this supplement to its 2013 Reconsideration Petition (hereinafter “Supplemental Petition”) and respectfully requests that EPA stay the effective date of the NOx BART FIP for Coronado and toll its compliance period.

\(^2\) SRP hereby reaffirms its request for relief as presented in the 2013 Reconsideration Petition. On February 1, 2013, SRP filed a petition for review of the Final Rule in the United States Court of Appeals for the Ninth Circuit. \textit{Salt River Project Agric. Improvement and Power Dist. v. United States EPA}, No. 13-70410. That case and other petitions for review of the Final Rule have been fully briefed. Oral argument before the court has not yet been scheduled.
SRP petitions EPA to stay the effectiveness of the Final Rule’s NOx BART determination for Coronado pursuant to the APA, 5 U.S.C. § 705, and section 307(d) of the CAA. SRP requests that EPA stay the effectiveness of, and toll the compliance period for, all of the Final Rule’s NOx BART requirements applicable to Coronado pending EPA’s final rulemaking action on the 111(d) Proposal and the effective date of the Agency’s final action approving or promulgating a complete plan implementing any section 111(d) requirements for Arizona. SRP further requests that the stay of the Final Rule’s NOx BART requirements for Coronado, and the tolling of the compliance period for those BART requirements, extend through the completion of any EPA rulemaking on reconsideration of any elements of those requirements. The grounds on which EPA should stay the FIP and toll its compliance period are discussed below. SRP respectfully renews and supplements its petition for reconsideration by EPA of the Final Rule pursuant to section 4(e) of the APA, which authorizes any interested person “to petition for the issuance, amendment, or repeal of a rule.” 5 U.S.C. § 553(e). SRP also renews and supplements its request for reconsideration pursuant to section 307(d)(7)(B) of the CAA, 42 U.S.C. § 7607(d)(7)(B), which provides that:

Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. . . . The effectiveness of the rule may be stayed during such reconsideration . . . by the Administrator or the court for a period not to exceed three months.
Section 307(d)(7)(B) applies to this rulemaking, in which EPA promulgated a FIP under section 110(c) of the Act, 42 U.S.C. § 7410(c), because section 307(d)(1)(B) of the Act, 42 U.S.C. § 7607(d)(1)(B), applies the provisions of CAA section 307(d) to “the promulgation or revision of an implementation plan by the [EPA] Administrator under section 110(c) of this Act.” See also 77 Fed. Reg. at 72,569 (recognizing that “the procedural requirements for promulgation of a FIP under [CAA section] 110(c) are set forth in CAA section 307(d)”). SRP raises the objections to the Final Rule described in the 2013 Reconsideration Petition and this Supplemental Petition because (i) it was not possible to raise these objections during the public comment period and (ii) the objections are of central relevance to the outcome of the rule. These objections are discussed below.

I. EPA Should Stay Its NOx BART Determination for Coronado Given the Uncertainty Created by EPA’s Proposed Carbon Dioxide Emission Standards for Existing Sources Under CAA § 111(d), by the Pendency of EPA’s Rulemaking on Those Proposed Standards, and by the Future Imposition of an Approved Final Section 111(d) Plan Implementing Any Final Standards for Arizona that Will Emerge from That Rulemaking.

On June 18, 2014, EPA published its 111(d) Proposal. Section 111(d) authorizes the EPA Administrator to “prescribe regulations which shall establish a procedure similar to that provided by section [110 of the CAA] under which each State shall submit to the Administrator a plan” that establishes “standards of performance” for existing sources of air pollutants, subject to certain limitations, and that “provides for the implementation and enforcement of such standards of performance.” 42 U.S.C. § 7411(d)(1). The Act further states:

The term “standard of performance” means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.
The centerpiece of EPA’s 111(d) Proposal is a set of CO₂ emission rate goals, with specific goals established for each state. Those goals include interim CO₂ emission rate goals to be achieved as an average over the course of an interim compliance period of 2020 to 2029 and final goals to be achieved by 2030 and to be maintained thereafter. See 79 Fed. Reg. at 34,895. EPA developed the goals for each state by applying four “Building Blocks” reflecting various policies that, in the Agency’s view, could achieve CO₂ emission reductions from a 2012 baseline. The Building Blocks are:

1. Reducing the carbon intensity of generation at individual affected EGUs [electric generating units] through heat rate improvements.

2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including NGCC [natural gas combined cycle] units under construction).

3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.

4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

Id. at 34,836. According to EPA, the policies embodied in the four Building Blocks and the CO₂ emission reductions that EPA projects those policies can achieve, taken together, constitute the “best system of emission reduction . . . adequately demonstrated,” or “BSER.” Id. Thus, EPA asserts that the state goals it has identified based on this definition of BSER will be binding on the states and that the states will be required to develop plans implementing the four Building Blocks, or some variation on the four Building Blocks, to ensure that each state meets its goals. Id. at 34,893.
For Arizona, the 111(d) Proposal would impose exceptionally stringent goals, including an interim goal of 735 and a final goal of 702, expressed as an adjusted output-weighted-average of pounds of CO₂ per net MWh from all affected fossil fuel-fired EGUs. *Id.* at 34,895, Table 8. As noted above, these goals reflect policy measures such as shifting EGU dispatch from coal-fired generation sources like Coronado to less carbon-intensive fossil fuel-fired EGUs, redispatch from coal-fired EGUs like Coronado to new renewable energy generation, and reducing generation at affected EGUs like Coronado through demand-side management.

Implementation of any program to achieve these CO₂ emission rate goals for Arizona almost certainly would result in the forced shutdown of Coronado Units 1 and 2 by 2020. For purposes of setting Arizona’s goals, EPA assumed that Arizona would have no coal-fired generation beyond 2020. *See* Technical Support Document: Goal Computation, Appendix 1, Docket ID No. EPA-HQ-OAR-2013-0602. As explained in the Declaration of Thomas Cooper (Attachment B hereto), retirement by 2020 of all coal-fired generation subject to Arizona’s regulatory jurisdiction is the only feasible path to reach the state’s interim goal as stated in the 111(d) Proposal. Cooper Decl. ¶ 7. SRP’s analysis further shows that it would be necessary to nearly double the use of renewable energy resources and energy efficiency programs (in addition to implementing all redispatching measures needed to comply with the interim goal) to preserve approximately 400 MW of coal-fired capacity operating in an economically reasonable manner. *Id.* ¶ 8. Even under this implausible scenario, it is unlikely that Coronado would survive. As the Cooper Declaration explains, there are other coal-fired EGUs in Arizona that are newer than the Coronado units and that are among the best-controlled coal-fired units, in terms of air emissions, in the state. *Id.* ¶ 10. Those EGUs would be more economical to continue in operation than the Coronado units. *Id.* The likely impacts of a final rule comparable to the 111(d) Proposal
undermine the basis for the NOx BART determination for Coronado contained in the Final Rule. The uncertainty created by EPA’s 111(d) Proposal therefore warrants a stay of the NOx BART FIP requirements, and a tolling of the compliance period for those requirements, for Coronado until EPA completes its section 111(d) rulemaking and takes final action on a plan implementing any section 111(d) requirements for Arizona. At that time, if a rule comparable to the 111(d) Proposal will require that Coronado shut down, reconsideration by EPA of the Final Rule’s NOx BART requirements for Coronado would be necessary in light of that fundamental change in the circumstances affecting Coronado.

Compliance with the NOx BART FIP for Coronado requires SRP to install costly selective catalytic reduction ("SCR") emission control technology on Coronado Unit 1. SRP estimates that installing and operating SCR at Unit 1 will cost at least $110 million (in 2014 dollars) and projects that it must begin spending very substantial additional amounts in the near future to meet the FIP’s December 5, 2017 compliance deadline. As explained in the Declaration of James M. Pratt (Attachment A hereto), SRP has already spent approximately $779,000 toward installation of SCR at Coronado Unit 1. Pratt Decl. ¶ 11, Table 1. SRP estimates that it will have to spend approximately $14,786,000 in 2015 for the Unit 1 SCR project, and that it will have spent approximately $3,000,000 for that project before EPA is scheduled to take final action on the 111(d) Proposal in June 2015. Id. ¶ 11. SRP expects to spend approximately $23,832,000 in 2016, $68,422,000 in 2017, and $1,950,000 in 2018. Id. ¶ 11, Table 1. EPA’s 111(d) Proposal would require states, including Arizona, to develop and submit to EPA their section 111(d) implementation plans, and additional time would pass

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3 As Mr. Pratt’s Declaration explains, the current cost estimates described herein represent the low end of the range of current estimates. SRP expects costs to increase as the project proceeds further. Pratt Decl. ¶ 11.
thereafter before EPA would take final action to approve or disapprove a submitted state plan (or to promulgate a plan of the Agency’s own in the event the state does not submit a plan or submits a plan that EPA disapproves). Thus, it is indisputable that, to be in a position to comply with the NOx BART Final Rule (to the extent compliance with that rule is feasible at all), SRP will have to spend very substantial sums – totaling in the tens of millions of dollars – toward the installation of the Unit 1 SCR before the uncertainty created by the 111(d) Proposal is resolved.

For EPA to require such significant expenditures at this time – when there is a serious risk, created by the 111(d) Proposal, that Coronado will have to be shut down by 2020 – is unreasonable. Equally important, it would be inconsistent with the BART provisions of the CAA and EPA’s rules implementing those provisions. Section 169A of the Act and EPA’s BART rules require states, and EPA when it is acting in the place of a state, to take into account “the remaining useful life” of a facility when determining BART. CAA § 169A(g)(2) (defining BART); 40 C.F.R. § 51.308(e)(1)(ii)(A). Indeed, the remaining useful life of a facility can have a determining effect as to whether installation of emission controls will be cost-effective, a critical factor in determining BART. For Coronado, EPA used an assumption of a 20-year remaining useful life in determining BART. See 77 Fed. Reg. 42,834, 42,864 (July 20, 2012). As EPA explained in its proposed NOx BART FIP for Coronado, using “a 20-year amortization period” in the Agency’s emission control cost calculations led EPA to conclude that “the most stringent available control option, SCR with LNB [low NOx burners] and OFA [overfire air], . . . [is] cost-effective.” Id.

There is no way that SRP could recoup its investment in SCR at Coronado Unit 1 over a two-year amortization period (a period that reflects the interval between the BART FIP’s December 2017 compliance deadline and the date when Unit 1 would have to shut down to meet
the CO₂ emission goal as set forth in EPA’s 111(d) Proposal), and it is inconceivable that EPA would have imposed a requirement that SRP install SCR using such an extraordinarily abbreviated “remaining useful life.” EPA’s NOₓ BART determination for Coronado, using a 20-year remaining useful life, relies on an average cost-effectiveness value of $2,135 per ton of NOₓ removed and an incremental cost-effectiveness value of $1,918 per ton of NOₓ removed. 77 Fed. Reg. at 72,560, Table 17. Calculating cost-effectiveness using a two-year remaining useful life (while retaining all of EPA’s other assumptions in its cost-effectiveness analysis) would result in an estimated average cost-effectiveness value of $17,379 per ton of NOₓ removed. Pratt Decl. ¶ 12, Table 2. This dollar-per-ton cost-effectiveness value vastly exceeds both the value on which EPA relied in establishing the FIP’s NOₓ BART requirement for Coronado, as discussed above, and the $2,000-to-$6,000 per-ton cost-effectiveness range that EPA itself has identified as reasonable where SCR has been determined to be BART for NOₓ. Id. ¶ 12; 79 Fed. Reg. 46,514, 46,523 (Aug. 8, 2014).

If the circumstances that will face Coronado in the event the 111(d) Proposal is made final had applied at the time EPA made its BART determination for Coronado, EPA likely would have approved the BART determination for Coronado in Arizona’s state implementation plan, which required LNB and OFA at Unit 1, a much less costly though still effective approach to NOₓ emission control. See 77 Fed. Reg. at 42,842, Table 3. EPA could not have imposed a BART requirement compelling installation of SCR at Coronado Unit 1 under those circumstances. When the assumptions underlying an agency’s regulations prove to be false over time, the agency is obligated to revisit its regulatory determinations and revise them to reflect the world as it exists. See, e.g., Natural Res. Def. Council v. Jackson, 650 F.3d 662, 665-66 (7th Cir. 2011).
In light of the overwhelming uncertainty that SRP now faces as a result of EPA’s section 111(d) rulemaking, as well as the reasons explained in the 2013 Reconsideration Petition, EPA should immediately stay the Final Rule establishing NOx BART requirements for Coronado and toll the Final Rule’s compliance period for Coronado until EPA has taken final rulemaking action on its 111(d) Proposal and until the effective date of an EPA-approved or EPA-promulgated plan to implement a final section 111(d) rule for Arizona. Only after those regulatory actions have been completed could SRP reasonably determine whether installation of SCR at Coronado Unit 1 is viable, and, equally important, only then will EPA be able to determine whether and how it must revise the NOx BART requirements for Coronado on reconsideration to address potential conflict with section 111(d) regulation.

II. Statutory Authority and the Factors Courts Use To Evaluate Whether a Stay Is Warranted Support Issuance of an Administrative Stay of the Final Rule for Coronado.

Because of the substantial uncertainty described above, SRP respectfully requests that EPA grant an immediate administrative stay of the effective date of, and toll the compliance period for, the requirements of the FIP in the Final Rule as to Coronado, pending EPA’s final action on its 111(d) Proposal and the effective date of final EPA action approving or promulgating a complete plan to implement any section 111(d) requirements for Arizona. The statutes that govern issuance of administrative stays and the factors that courts consider in deciding whether to grant a stay support EPA’s issuance of a stay here.

Two statutes – the APA and the CAA – authorize an administrative stay of the Final Rule, and SRP respectfully requests that EPA take action and grant effective relief under both. Section 10(d) of the APA grants EPA authority to stay the Final Rule: “When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review.” 5 U.S.C. § 705. CAA section 307(d)(7)(B), which grants the Administrator authority
to convene reconsideration proceedings with respect to FIPs, also authorizes the Administrator to stay the effectiveness of a FIP during its reconsideration for up to three months. 42 U.S.C. § 7607(d)(1)(B), (7)(B). This provision authorizes a stay in conjunction with a determination by EPA to convene reconsideration proceedings, and EPA should exercise that authority here along with its authority to issue a stay under the APA.

Although these statutory provisions give EPA exceptionally broad authority to grant stays, agencies often refer to criteria governing preliminary injunction requests before federal courts when they determine whether to exercise this authority. See, e.g., Corning Savings & Loan Ass’n v. Fed. Home Loan Bank Bd., 562 F. Supp. 279, 280 (E.D. Ark. 1983) (“the test to be applied as to whether a stay [pursuant to 5 U.S.C. § 705] should be entered is the same as that which applies to requests for preliminary injunctions”). The test applied by courts does not control EPA’s decision whether to grant a stay here, and it is clear that the APA’s broadly applicable “when justice so requires” standard is satisfied in any event for the reasons described in this Supplemental Petition and the 2013 Reconsideration Petition. Nevertheless, SRP addresses that test below.

As the Supreme Court has stated, “[a] plaintiff seeking a preliminary injunction must establish that he is likely to succeed on the merits, that he is likely to suffer irreparable harm in the absence of preliminary relief, that the balance of equities tips in his favor, and that an injunction is in the public interest.” Winter v. Natural Res. Def. Council, Inc., 555 U.S. 7, 20 (2008); see also, e.g., Am. Trucking Ass’ns, Inc. v. Los Angeles, 559 F.3d 1046, 1052 (9th Cir. 2009); Washington Metro. Area Transit Comm’n v. Holiday Tours, Inc., 559 F.2d 841, 843 (D.C. Cir. 1977). An agency or a court reviewing a request for a stay is not to review each of these factors in a rigid or isolated manner. On the contrary, the United States Court of Appeals for the
Ninth Circuit, for instance, has adopted a “sliding scale” approach to the criteria for preliminary injunctions. Under this approach, “the elements of the preliminary injunction test are balanced, so that a stronger showing of one element may offset a weaker showing of another.” *Alliance for the Wild Rockies v. Cottrell*, 632 F.3d 1127, 1131-32 (9th Cir. 2011).

For the reasons described below, SRP satisfies each of the stay factors. EPA should stay the effectiveness of, and toll the compliance period for, all of the Final Rule’s NOx BART requirements applicable to Coronado pending EPA’s final rulemaking action on the 111(d) Proposal and the effective date of final EPA action approving or promulgating a complete plan implementing any section 111(d) requirements for Arizona, and the stay and tolling should extend through the completion of any EPA rulemaking on reconsideration of any elements of the NOx BART requirements for Coronado.

A. **SRP Is Likely To Succeed on the Merits in Its Challenge to the Final Rule.**

Briefing of the petitions for review of EPA’s Final Rule in the Ninth Circuit was completed in March 2014. SRP believes that, based on the strength of the briefs filed with the court, the arguments it has advanced in challenging the Final Rule as to Coronado have a likelihood of success. EPA, however, need not share SRP’s view of this matter in order to grant the relief SRP requests. As noted above, the Ninth Circuit uses (as do many other courts) a “sliding scale” approach that “balance[s]” the factors, “so that a stronger showing of one element may offset a weaker showing of another.” *Alliance for the Wild Rockies*, 632 F.3d at 1131.

Accordingly, EPA may grant the stay that SRP requests based on the existence of serious, substantial, or difficult questions going to the merits of the challenges to the Final Rule with respect to Coronado. *See, e.g., Fed. Lands Legal Consortium v. United States*, 195 F.3d 1190, 1194-95 (10th Cir. 1999) (citing *Walmer v. United States Dep’t of Def.*, 52 F.3d 851, 854 (10th Cir. 1995)); *see also Alliance for the Wild Rockies*, 632 F.3d at 1134-35..
SRP has identified serious and substantial legal questions in its challenge to the BART FIP with respect to Coronado. As discussed in the 2013 Reconsideration Petition and in its briefs in the Ninth Circuit litigation, SRP’s arguments address, for example, the CAA’s division between states and the federal government of responsibility for implementing the regional haze program, EPA’s failure to properly take Coronado’s prevention of significant deterioration (“PSD”) consent decree into account as required by EPA’s BART Guidelines, EPA’s unsupported BART analysis, and EPA’s violation of CAA procedural requirements.

Moreover, as explained in section I above, there are now additional grounds for concluding that SRP will succeed in a challenge to the NOx BART FIP for Coronado. The 111(d) Proposal further undermines the validity of the analysis underlying EPA’s SCR-based BART determination for Coronado. As discussed above, section 111(d) regulations such as those in EPA’s June 2014 proposed rule would almost certainly require SRP to close Coronado by 2020, far sooner than EPA’s BART analysis assumed. For the reasons discussed above, the difference between EPA’s 20-year assumed “remaining useful life” for BART analysis purposes and the far shorter remaining useful life that would result from the implementation of a final rule like the 111(d) Proposal means that a BART determination very different from that in the FIP would have to be made – one that could not be based on installation and operation of an SCR at Coronado Unit 1.

EPA should take into account the nature, number, and seriousness of the arguments that SRP has presented as EPA evaluates this factor. Indeed, even if EPA believes it may ultimately be able to support the relevant elements of the Final Rule on the merits after judicial review, the merits arguments SRP has identified undoubtedly raise, at the very least, “serious questions
going to the merits,” which satisfies the stay test adopted by the Ninth Circuit. *Alliance for the Wild Rockies*, 632 F.3d at 1131-32 (internal quotations omitted).

**B. SRP Will Suffer Irreparable Harm in the Absence of a Stay.**

The uncertainty created by EPA’s regulatory actions places SRP in an untenable position. EPA’s Final Rule requires SRP to complete installation of emission controls and to comply with the FIP’s NOx emission limit for Coronado by December 5, 2017. This means that SRP must undertake near-term steps to procure the goods and services necessary to construct SCR at Coronado Unit 1, incurring enormous costs that will not be recoverable from EPA if the Final Rule ultimately is found to be invalid. *See* Pratt Decl. ¶ 11. The financial harm to SRP would grow exponentially as a result of EPA’s regulations to control CO₂ emissions from existing EGUs. The 111(d) Proposal, if promulgated in final form and implemented through an EPA-approved state section 111(d) plan or an EPA-promulgated federal section 111(d) plan, almost certainly would force Coronado to cease operations by 2020, drastically reducing the lifespan of an otherwise viable power plant. Forced installation of expensive SCR emission controls, estimated to cost approximately $110 million (in 2014 dollars), combined with the loss of the majority of the period that EPA itself concluded would be needed to amortize those emission controls, would impose a massive monetary loss on SRP due to the EPA-imposed legal obligation to comply with a BART determination that would not be valid and supportable in a post-section-111(d)-rule scenario. SRP’s only alternative would be to shut down Coronado in December 2017 to avoid noncompliance with the NOx BART FIP. The loss of substantial generating capacity and existing investments in Coronado, including recent expenditures of over $470 million to comply with the Coronado consent decree, would also constitute irreparable harm. *See* Pratt Decl. ¶ 11.
In evaluating whether an injury amounts to “irreparable harm” of the sort warranting a stay of an agency rule, courts often consider three factors: (1) the substantiality of the injury alleged; (2) the likelihood of its occurrence; and (3) the adequacy of the proof provided. See Cuomo v. Nuclear Regulatory Comm’n, 772 F.2d 972, 977 (D.C. Cir. 1985). As discussed below, the facts presented by this case demonstrate that SRP will suffer irreparable harm if a stay of the FIP’s effectiveness and a concomitant tolling of the FIP’s compliance period are not granted.

**SRP will suffer substantial injury in the absence of a stay of the FIP’s effective date and a tolling of the FIP’s compliance period.** As stated above, SRP will be forced to spend approximately $110 million to install SCR at Coronado Unit 1. SRP estimates that it will have to spend approximately $14,786,000 in 2015 and that it will have spent approximately $3,000,000 before EPA is scheduled to take final action on the 111(d) Proposal in June 2015. Pratt Decl. ¶ 11 & Table 1. Further, SRP estimates that it will spend approximately $23,832,000 in 2016, $68,422,000 in 2017, and $1,950,000 in 2018. Id. ¶ 11, Table 1. Most, if not all, of these expenditures may take place before EPA takes final action to approve or promulgate a plan implementing section 111(d) requirements for sources in Arizona, including Coronado. These enormous investments will be stranded if SRP is forced to (a) comply with the NOx BART FIP but then (b) shortly thereafter close Coronado to comply with section 111(d) requirements. As stated above, the only way to avoid these costs is to shut down Coronado in December 2017, which itself constitutes irreparable harm.

Courts generally have recognized the principle that monetary injury should be considered irreparable harm if there is no opportunity for compensation through litigation. See, e.g., Cal. Pharmacists Ass’n v. Maxwell-Jolly, 563 F.3d 847, 852 (9th Cir. 2009) (holding that monetary
injury is irreparable where sovereign immunity prevents recovery), overturned on other grounds, *Douglas v. Independent Living Ctr. of Southern Cal., Inc.*, 132 S. Ct. 1204 (2012); see also *Conte v. Transglobal Assets*, 2012 WL 4092717 at 1 (D. Nev. Sept. 17, 2012) (continuing to apply *California Pharmacists*’ irreparable harm holding after issuance of the Supreme Court’s decision in *Douglas*); *Arizona Hosp. and Healthcare Ass’n v. Betlach*, 865 F. Supp. 2d 984, 998 (D. Ariz. 2012) (same). No mechanism is available to SRP to recover its costs from EPA if it is forced by the BART FIP to install SCR and that FIP is then found to have been promulgated unlawfully. Further, if SRP is forced to close Coronado as a result of EPA’s section 111(d) rulemaking, the enormous stranded expenditure for SCR would be an injury for which no adequate legal remedy would be available. Likewise, being forced to close Coronado in December 2017 to avoid noncompliance with the Final Rule would constitute irreparable injury.

In addition, EPA’s continued lack of action on SRP’s request for reconsideration and for a stay and tolling of the NOx BART requirements as requested by SRP’s 2013 Reconsideration Petition also threatens SRP with substantial irreparable harm. In the absence of relief provided in response to that Petition, as supplemented herein, SRP will need to file permit applications in early 2015 to obtain approval of the actions that SRP must take to comply with the Final Rule’s NOx BART FIP requirements. See Pratt Decl. ¶ 7. As EPA’s April 2013 decision to grant reconsideration of the NOx BART FIP’s compliance methodology and the plantwide-averaged NOx BART limit for Coronado implies, there is a serious possibility that SRP will – even apart from the uncertainty created by the 111(d) Proposal and by the pendency of EPA’s section 111(d) proceedings – be unable to comply with the NOx BART FIP in its current form. As a result, EPA’s failure to act on the 2013 Reconsideration Petition, including that petition’s stay request, creates the distinct possibility that Coronado’s plant manager will be unable to make the
attestations regarding Coronado’s future compliance with the Final Rule’s NOx BART requirements that would have to be made to support those permit applications and to obtain issuance of the permits that are necessary to proceed with SCR installation at Unit 1. *Id.*

_It is very likely that SRP will suffer substantial harm in the absence of a stay of the FIP’s effective date and a tolling of the FIP’s compliance period._ The harm that SRP will suffer is in no way speculative. SRP will incur significant BART compliance costs before EPA takes final action on its 111(d) Proposal. Further, SRP could be forced to complete all NOx BART compliance expenditures before EPA takes final action on a plan implementing section 111(d) in Arizona. Incurring these costs, which cannot be recovered from EPA, while facing the enormous uncertainty presented by the 111(d) Proposal and EPA’s section 111(d) proceedings constitutes substantial harm that can be avoided only by a stay of the Final Rule and a tolling of that rule’s compliance period.

_SRP has submitted adequate proof of substantial harm._ With the 2013 Reconsideration Petition and the present Supplemental Petition, SRP has submitted declarations as factual support for its request for a stay of the FIP’s effective date and a tolling of its compliance schedule. The Pratt Declaration that is Attachment A hereto explains the amount and timing of expenditures that SRP must make to comply with the NOx BART FIP for Coronado, and the Cooper Declaration that is Attachment B hereto describes SRP’s analysis confirming that compliance with the 111(d) Proposal almost certainly would require Coronado to cease operations by 2020. These declarations provide substantial evidence to support SRP’s entitlement to a stay of the FIP’s effective date and a tolling of its compliance period.
C. The Balance of Equities Favors Granting SRP’s Stay Request, and Granting a Stay Is in the Public Interest.

The balance of equities and the public interest strongly support issuance of a stay of the Final Rule’s NOx BART FIP for Coronado immediately and pending EPA’s final action on its 111(d) Proposal and the effective date of final EPA action on a plan to implement any section 111(d) requirements for Arizona. The serious harm to SRP and to the public interest if a stay is not granted weigh heavily in favor of granting this stay request.

As discussed above, under the Final Rule, SRP must make enormous expenditures to implement the NOx BART FIP for Coronado by December 2017 (or else be compelled to shut down Coronado by that date to avoid noncompliance with that FIP), while at the same time it faces the near-certain prospect of being forced to close Coronado only two years later if EPA makes the 111(d) Proposal final. This enormous uncertainty and the prospect of serious, irremediable loss to SRP weigh heavily in favor of granting a stay.

The stay and tolling that SRP requests will not harm EPA. On the contrary, the stay will allow EPA to coordinate its BART actions and its section 111(d) proceedings, coordination that EPA should have undertaken on its own. Moreover, EPA will not, as a result of staying the rule and tolling its compliance schedule, fall out of compliance with any of its statutory or regulatory obligations. In short, EPA would not be injured by exercising a legitimate statutory authority to toll the BART FIP’s compliance period pending completion of all regulatory proceedings necessary to implement any section 111(d) requirements for Arizona.

Similarly, any arguable harm to the public interest that might result from staying the Final Rule would be minimal. Coronado’s NOx emissions are already well-controlled, and, as explained above, those emissions would be further reduced or eliminated entirely in the future depending on the outcome of EPA’s section 111(d) proceedings.
III. EPA Should Reconsider the NOx BART FIP for Coronado, Revise That FIP Through Notice-and-Comment Rulemaking, and Stay the Effective Date of and Toll the Compliance Period for the Existing NOx BART FIP for Coronado Until After Completion of New Rulemaking on a Revised FIP.

EPA should provide effective relief in response to SRP’s 2013 Reconsideration Petition, as supplemented by this petition, and revise the NOx BART FIP limit and its compliance deadline through public notice-and-comment rulemaking. As noted above, EPA has already stated its intent to consider taking this sort of rulemaking action. In its April 9, 2013 letter, EPA announced it was “granting reconsideration of the compliance methodology for NOx at Coronado.” Letter from Jared Blumenfeld, EPA Region 9 Administrator, to Norman W. Fichthorn, Hunton & Williams LLP, Counsel for SRP at 1 (Apr. 9, 2013). In addition, EPA stated that “because we initially proposed different NOx emission limits for Coronado Units 1 and 2, we also intend to seek comment on the emission limits for each of those two units.” *Id.*

If EPA were to provide effective relief to SRP on reconsideration of these matters and substantively revise the NOx BART limit applicable to Coronado, EPA could and should also revise the compliance deadline for the revised BART limit and provide SRP with five years from the effective date of final EPA rulemaking action on reconsideration to install the emission controls necessary to comply with the Agency’s revised BART determination. Revision of the Final Rule through notice-and-comment rulemaking that would also extend the NOx BART compliance deadline for Coronado likely would provide SRP with at least a substantial measure of the needed relief from the uncertainty created by the 111(d) Proposal by allowing SRP to defer many, if not all, of its NOx BART compliance expenditures until it has become clear whether final section 111(d) requirements will force Coronado to shut down. However, because, as discussed above, SRP will have to make very substantial expenditures in the near term to comply with the *existing* NOx BART FIP for Coronado, it will in all events be necessary for
EPA to immediately stay the existing FIP’s effectiveness and toll that FIP’s compliance schedule while the Agency undertakes and completes notice-and-comment rulemaking on a revised BART limit and compliance deadline.

**IV. Conclusion**

For the foregoing reasons, SRP respectfully requests that EPA immediately grant SRP’s request for a stay of the effective date of, and a tolling of the compliance period for, the Final Rule’s provisions that address Coronado’s NOx emissions pending EPA’s final rulemaking action on its 111(d) Proposal and pending the effective date of EPA approval or promulgation of a complete plan to implement any section 111(d) requirements in Arizona. EPA also should provide effective relief in response to SRP’s 2013 Reconsideration Petition, as supplemented by this petition, by revising the NOx BART limit and compliance deadline for Coronado and, in the meantime, by immediately staying the existing FIP’s effective date and tolling its compliance period pending completion of rulemaking on establishment of a revised BART limit and a revised compliance deadline applicable to that new limit.
Supplemental Petition of Salt River Project Agricultural Improvement and Power District for Partial Reconsideration and Stay of EPA’s Final Rule: “Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans”

Attachment A
DECLARATION OF JAMES M. PRATT
IN SUPPORT OF THE SUPPLEMENTAL PETITION OF
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER
DISTRICT FOR PARTIAL RECONSIDERATION AND STAY OF
EPA’S FINAL RULE: “APPROVAL, DISAPPROVAL AND PROMULGATION
OF AIR QUALITY IMPLEMENTATION PLANS; ARIZONA;
REGIONAL HAZE STATE AND FEDERAL IMPLEMENTATION PLANS”

I, James M. Pratt, having first been duly sworn upon my oath, declare and state as
follows:

1. My name is James M. Pratt, and I am the Senior Director of Baseload Generation
for Salt River Project Agricultural Improvement and Power District (“SRP”). My business
address is POB002, 6504 East Thomas Road, Scottsdale, Arizona 85251-6008. I am competent
to testify concerning the matters in this declaration. I received a Bachelor of Science degree in
Mechanical Engineering from Montana State University in 1983. I have more than 30 years of
experience in the electric utility industry. I have held a variety of management positions at SRP
in engineering, maintenance and operations at several gas and coal generation facilities, as well
as in transmission planning.

2. In my current position with SRP, I am responsible for the operation of two coal
generation facilities operated by SRP – the Coronado Generating Station (“Coronado”) and the
Navajo Generating Station. I also represent SRP’s interests with respect to the other coal
generation facilities in which SRP holds interests but which are operated by other utilities. In
addition, I oversee engineering support for SRP’s generation assets and the construction of
generation-related major projects, such as emission control improvements.

3. As I stated in support of SRP’s initial petition for partial reconsideration
submitted to the U.S. Environmental Protection Agency (“EPA” or “Agency”) on February 4,
2013 (Attachment A-1), I served as the lead technical representative for the negotiation of a consent decree entered into with EPA to resolve alleged violations of Prevention of Significant Deterioration ("PSD") requirements under the Clean Air Act at Coronado. After extensive negotiations with EPA, a consent decree was entered by the U.S. District Court for the District of Arizona on August 12, 2008. This consent decree resolved alleged PSD violations for both Coronado units. *U.S. Environmental Protection Agency v. Salt River Project Agricultural Improvement and Power District*, Case 2:08-cv-014790JAT (D. Ariz. 2008) ("consent decree").

To comply with the consent decree, SRP agreed to install and has installed low NOx burners ("LNB") with overfire air ("OFA") systems and wet flue gas desulfurization ("WFGD") equipment on both units at Coronado. SRP also installed selective catalytic reduction ("SCR") equipment on Unit 2, and that SCR began operation in May 2014 as set forth in the consent decree.

4. This declaration is submitted in support of SRP’s supplemental petition for partial reconsideration of the final rule issued by EPA, titled “Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Final Rule,” 77 Fed. Reg. 72512 (December 5, 2012) ("Final Rule"), and for a stay of the effective date of — and tolling of the compliance period for — the federal implementation plan ("FIP") promulgated as part of the Final Rule. In its initial petition for partial reconsideration of the Final Rule, SRP challenged certain elements of EPA’s best available retrofit technology ("BART") determination affecting Coronado and sought a stay of the effective date of the FIP for Coronado pending administrative reconsideration and pending the conclusion of a litigation appeal of that portion of the Final Rule. In its supplemental petition, SRP renews and
supplements its request for reconsideration and a stay in light of developments since the filing of that petition.

5. SRP is a political subdivision of the State of Arizona that provides retail electric services to almost one million residential, commercial, industrial, agricultural and mining customers in a 2,900-square-mile area in Arizona. SRP has ownership interests in six coal-fired power plants located in Arizona, New Mexico, and Colorado and in five natural gas-fired power plants located in central Arizona. SRP operates two of the coal-fired plants, including Coronado, and all of the natural gas-fired plants. SRP also has interests in other generating resources, including nuclear, natural gas, and renewable sources, such as hydroelectric, solar, wind and geothermal.

6. Coronado is a 773 net-MW coal-fired, steam electric generating station located near St. Johns, Arizona. Coal is currently provided to the plant from the Powder River Basin. Coronado recently completed the installation of the emission controls required under the aforementioned consent decree, so now the following controls are in place:

   Unit 1 – LNB with OFA; WFGD System; Hot-Side Electrostatic Precipitator ("ESP")
   Unit 2 – SCR; LNB with OFA; WFGD System; Hot-Side ESP

7. The Final Rule mandates that SRP must attain a nitrogen oxide ("NOx") emission limit of 0.065 pounds per million British thermal units ("lb/mmBtu") at Coronado, determined as an average of Coronado Units 1 and 2, based on a rolling 30-boiler-operating-day ("BOD") average. As explained in SRP’s initial petition for reconsideration, the established emission limit is infeasible because it fails to provide an adequate compliance margin for Coronado to maintain continuous compliance. In my prior declaration, I provided information that explained why the emission rate was not an appropriate limit and why the plant-wide NOx averaging methodology
was not an appropriate compliance methodology. That explanation focused on technical reasons as to why the Final Rule did not provide an adequate compliance margin and how the Final Rule’s plant-wide averaging methodology, which is a novel concept, does not work when applied to actual plant operations. I included specific examples to illustrate the compliance problems. As I noted, the Final Rule included compliance requirements that, if left unaltered, likely would mean that Coronado would be unable to achieve continuous compliance with the Final Rule. The Final Rule requires the installation and operation of SCR technology on Unit 1 by December 5, 2017. In an April 9, 2013 letter, EPA stated that it was granting reconsideration on the compliance methodology and the NOx emission limit applicable to Coronado. EPA has failed to take further action on reconsideration. That failure risks irreparable harm to SRP. In the absence of a stay of the FIP and a tolling of the FIP’s compliance period, SRP will need to file permit applications in early 2015 to obtain approval of the actions that SRP must take to comply with the Final Rule’s NOx BART FIP requirements. As EPA’s decision to grant reconsideration of the NOx BART FIP’s compliance methodology and the plantwide-averaged NOx BART limit for Coronado implies, there is a serious possibility that SRP will be unable to comply with the NOx BART FIP in its current form. As a result, there is a distinct possibility that Coronado’s plant manager will be unable to make the attestations regarding Coronado’s future compliance with the FIP that would have to be made to support those permit applications and to obtain issuance of the permits that are necessary to proceed with the SCR installation at Unit 1.

8. SRP’s concerns regarding specific emission compliance requirements remain unchanged, but the overall situation is now further aggravated by uncertainties stemming from EPA’s June 18, 2014 proposed emission guidelines to address greenhouse gas (“GHG”) emissions from existing fossil fuel-fired electric generating units (“EGUs”). See Carbon
Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units; EPA-HQ-OAR-2013-0602 ("111(d) Proposal"). SRP will be placed in an untenable position if it is required to install an SCR system on Unit 1 pursuant to the Final Rule and subsequently comply with a rule that is comparable to the 111(d) Proposal. As explained by Tom Cooper, SRP’s Director of Resource Planning & Development, SRP’s analysis of the 111(d) Proposal concludes that if the 111(d) Proposal were finalized as proposed, it would require both units at Coronado to shut down in 2020. Declaration of Thomas Cooper, ¶ 4.

9. As explained in SRP’s original petition, SRP believes that BART for Coronado should have been LNB and separated OFA, that compliance with the consent decree results in a better-than-BART level of emission control, and that, therefore, an SCR system is not required on Unit 1 as BART. Even if EPA and the U.S. Court of Appeals for the Ninth Circuit were to decide that the December 5, 2012 Final Rule requirement for an SCR system on Unit 1 was appropriate based on EPA’s prior BART determination, it is clear that such a determination would no longer be valid and supportable if the remaining useful life of Unit 1 were substantially shortened, as EPA envisions in the analysis supporting its 111(d) Proposal. The cloud of uncertainty that this situation creates is so substantial and the risk of being left with significant stranded investments is so high that a stay of the NOx BART FIP and a tolling of its compliance period should be issued by EPA now. If EPA takes those steps now, EPA could then determine whether reconsideration of the Final Rule is warranted after EPA takes final rulemaking action on the 111(d) Proposal and after the effective date of the Agency’s final action approving or promulgating a complete plan implementing any section 111(d) requirements for Arizona.

10. Reconsideration would clearly be warranted if the section 111(d) plan requirements for Arizona as finally approved or promulgated by EPA would lead to the early
shutdown of Coronado, as contemplated by the 111(d) Proposal. Under the Clean Air Act, one of the five factors that must be evaluated in a BART determination is the remaining useful life of the source. Clean Air Act § 169A(g)(2), 42 U.S.C. § 7491(g)(2). In the Final Rule, EPA assumed a 20-year remaining useful life for the Coronado units. See 77 Fed. Reg. at 72,532 (agreeing with a commenter that a 20-year useful life is an “appropriate” useful-life assumption). Because EPA assumed, for purposes of setting Arizona’s emission reduction goals in the 111(d) Proposal, that Coronado and all other coal-fired generation sources subject to Arizona’s regulatory jurisdiction would be shut down by 2020 to meet those goals, and because SRP’s analysis shows that the 111(d) Proposal would mean that both Coronado units would shut down by 2020, any SCR system installed on Coronado Unit 1 by December 2017 would effectively be in service for only two years (2018 and 2019). Given these circumstances, it would be implausible and entirely inconsistent with EPA’s own prior statements for EPA to continue to assert that any BART determination appropriately applying the Clean Air Act and EPA’s BART Guidelines could justify a requirement to install SCR as BART. This is especially so in light of the just-completed installation of LNB with OFA and WFGD on both Coronado units and an SCR system on Unit 2. The negligible incremental improvement in visibility and the enormous capital cost associated with an additional SCR system cannot be considered cost-effective for a facility with a remaining useful life of only two years.

11. The BART NOx emission limit imposed in the Final Rule for Coronado will require SRP to install an SCR system on Unit 1. SRP recently completed the installation of all the emission controls required at Coronado Unit 1 and Unit 2 by the consent decree. Final project close-out is underway, but it is anticipated the final project cost will be over $470 million. These costs were incurred primarily between 2009 and the first half of 2014. Based on these actual
costs and on preliminary vendor estimates, SRP estimates the Unit 1 SCR system capital cost to be at least $110 million in 2014 dollars. SRP has completed some of the upfront engineering and modeling work for the Unit 1 SCR but has delayed as much of the Unit 1 SCR system work as possible to avoid unnecessary expenses while awaiting EPA’s reconsideration of the Final Rule. SRP’s original cash flow was based on a project approach under which the engineering design, equipment procurement and installation would be performed in a series approach. This type of process minimizes design changes during the procurement and construction phase, which in turn helps to reduce costs. Delaying these work activities will require SRP to perform these project activities in more of a parallel effort, which very likely will reduce the amount of competitive procurement benefits and increase overall project costs. Table 1 shows a comparison of the prior project cost estimate to the current estimate:

Table 1: Estimated Approximate Annual Cash Flow for Installation of SCR on Coronado Unit 1

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>Estimated Expenditures (February 2013)</th>
<th>Actual + Remaining Estimated Expenditures (as of October 2014)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>$ 850,000</td>
<td>$ 779,000</td>
</tr>
<tr>
<td>2014</td>
<td>$ 5,000,000</td>
<td>$ 14,786,000</td>
</tr>
<tr>
<td>2015</td>
<td>$ 20,000,000</td>
<td>$ 23,832,000</td>
</tr>
<tr>
<td>2016</td>
<td>$ 55,500,000</td>
<td>$ 68,422,000</td>
</tr>
<tr>
<td>2017</td>
<td>$ 23,650,000</td>
<td>$ 1,950,000</td>
</tr>
<tr>
<td>Total</td>
<td>$ 105,000,000</td>
<td>$ 109,769,000</td>
</tr>
</tbody>
</table>

The current cost estimate set forth in Table 1 represents the low end of the current estimate and, based on SRP’s experience, I anticipate those costs to increase as the project moves forward. EPA is expected to take final action on the 111(d) Proposal by June 1, 2015. SRP estimates that
it will be required to spend approximately $3 million by that date in order to be able to install SCR at Unit 1 by the Final Rule's compliance deadline.

12. BART determinations must be based, in part, on a determination of the cost effectiveness of the emission controls that would be required as BART. Table 2 shows a comparison of the cost effectiveness of a Unit 1 SCR system assuming a 2-year remaining useful life rather than the otherwise-applicable 20-year remaining useful life, based on the capital costs described above. This clearly shows that an SCR system would not be required on Unit 1 when the impacts of what would be required by the 111(d) Proposal are considered. The annual dollar-per-ton cost of NOx removed is dramatically higher than the typical threshold that EPA considers reasonable for NOx BART determinations for EGUs. See 79 Fed. Reg. 46,514, 46,523 (Aug. 8, 2014) (EPA notes with respect to the Navajo Generating Station that “the cost-effectiveness values calculated by both EPA and SRP for SCR+LNB/SOFA are lower than or within the range of other BART evaluations where EPA or a state has determined that SCR is BART (ranging from approximately $2,000 to $6,000 per ton)” (emphasis added).

Table 2: Comparison of SCR Cost Effectiveness

<table>
<thead>
<tr>
<th>Assumptions</th>
<th>20 Year Remaining Useful Life</th>
<th>2 Year Remaining Useful Life</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual O&amp;M Cost</td>
<td>$ 4,492,736</td>
<td>$ 4,492,736</td>
</tr>
<tr>
<td>Capital Cost</td>
<td>$ 109,769,000</td>
<td>$ 109,769,000</td>
</tr>
<tr>
<td>Interest Rate</td>
<td>7%</td>
<td>7%</td>
</tr>
<tr>
<td>Remaining Useful Life</td>
<td>20</td>
<td>2</td>
</tr>
<tr>
<td>SCR Annual Capital Cost</td>
<td>$ 10,361,417</td>
<td>$ 60,712,332</td>
</tr>
<tr>
<td>Total Annual Cost</td>
<td>$ 14,854,153</td>
<td>$ 65,205,068</td>
</tr>
<tr>
<td>Annual Tons of NOx Removed</td>
<td>3,752</td>
<td>3,752</td>
</tr>
<tr>
<td>Annual $ / Ton</td>
<td>$ 3,959</td>
<td>$ 17,379</td>
</tr>
</tbody>
</table>
13. The unachievable emission limit and flawed compliance methodology in the Final Rule, coupled with the installation schedule required by the Final Rule and the substantial uncertainties for Coronado created by the pending 111(d) Proposal as discussed by Thomas Cooper in his declaration (see Cooper Decl., ¶¶ 7-10), mean that it would be completely illogical and irresponsible for SRP to move forward with installing an SCR system on Unit 1 in light of SRP’s obligation to provide its customers with cost-effective electricity. The only other option is to shut Unit 1 down on December 5, 2017, to avoid noncompliance with the Final Rule. This would mean that SRP’s customers would have to bear the cost of the stranded investment in the Unit 1 controls that SRP recently installed pursuant to the consent decree while not receiving any of the benefit from those expenditures. Therefore, it is a very reasonable request that EPA stay the Final Rule’s effective date, and toll the Final Rule’s compliance period, pending EPA’s final rulemaking action on the 111(d) Proposal and the effective date of EPA’s final action approving or promulgating a complete plan implementing section 111(d) requirements for Arizona, at which time the specific nature and scope of the impacts of section 111(d) requirements on Coronado’s future could be determined.

14. EPA itself recently recognized the potential conflict between the 111(d) Proposal and other Clean Air Act requirements. At a meeting of EPA’s Clean Air Act Advisory Committee on October 29, 2014, Tom Powers, EPA senior advisor on air quality, commented that EPA is considering providing states with a three-year extension of the deadline for submitting Clean Air Act state implementation plan revisions that include measures to address regional haze affecting visibility in national parks, for the purpose of allowing states time and opportunity to plan how the strategies in such regional haze plans might be coordinated with efforts to implement other Clean Air Act regulations, including prospective section 111(d)

Executed on November 11, 2014

James M. Pratt
Attachment A-1
BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Petition of Salt River Project Agricultural Improvement and Power District for Partial Reconsideration and Stay of EPA’s Final Rule: “Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans”


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Counsel for Salt River Project Agricultural Improvement and Power District

February 4, 2013
Petition of Salt River Project Agricultural Improvement and Power District for Partial Reconsideration and Stay of EPA’s Final Rule: “Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans”


February 4, 2013

Salt River Project Agricultural Improvement and Power District (“SRP”) hereby respectfully petitions the United States Environmental Protection Agency (“EPA” or “Agency”) to grant reconsideration of certain elements of EPA’s final rule entitled “Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans” as it applies to the Coronado Generating Station (“Coronado”). 77 Fed. Reg. 72512 (Dec. 5, 2012) (“Final Rule” or “rule”).  Specifically, SRP seeks reconsideration of the Final Rule’s requirements, contained in a federal implementation plan (“FIP”), for best available retrofit technology (“BART”) for emissions of nitrogen oxides (“NOx”) at Coronado and the provisions of the rule that require use of a novel plantwide 30-boiler-operating-day convention.

SRP also hereby petitions EPA to stay the effectiveness of the Final Rule’s NOx BART determination for Coronado pursuant to the Clean Air Act (“CAA” or “the Act”). In addition, SRP independently petitions EPA, pursuant to the Administrative Procedure Act (“APA”), 5 U.S.C. § 705, to grant an administrative stay of the effectiveness of, and toll the compliance period for, all of the Final Rule’s NOx BART requirements applicable to Coronado, pending completion of judicial review of the FIP.¹

SRP petitions for reconsideration and for a CAA stay pursuant to section 307(d)(7)(B) of the CAA, 42 U.S.C. § 7607(d)(7)(B), which provides that:

Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b) of this section). Such reconsideration shall not postpone the effectiveness of the rule. The effectiveness of the rule may be stayed during such reconsideration, however, by the Administrator or the court for a period not to exceed three months.

Section 307(d)(7)(B) applies to this rulemaking, in which EPA promulgated a FIP under section 110(c) of the Act, 42 U.S.C. § 7410(c), because section 307(d)(1)(B) of the Act, 42 U.S.C. § 7607(d)(1)(B), applies the provisions of CAA section 307(d) to “the promulgation or revision of an implementation plan by the [EPA] Administrator under section 110(c) of this Act.” See also 77 Fed. Reg. at 72569 (recognizing that “the procedural requirements for promulgation of a FIP under [CAA section] 110(c) are set forth in CAA section 307(d)”).

SRP raises the objections to the Final Rule described in this petition because the grounds for these objections (i) arose after the period for public comment on the proposed rule, but within the time specified for judicial review, or otherwise were impracticable to raise during the public comment period, and (ii) are of central relevance to the outcome of the rulemaking. These
objections are discussed in Section II below, which also addresses SRP’s request for a stay under the CAA.

As noted above, SRP also seeks an administrative stay under the APA of the effectiveness of all of the Final Rule’s NOx BART requirements that apply to Coronado pending completion of judicial review of the Final Rule. SRP makes this request pursuant to 5 U.S.C. § 705, which provides that “[w]hen an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review.”

I. **Background**

Coronado is a coal-fired, steam electric generating station, located near St. Johns in eastern Arizona. The 773 net megawatt (“MW”) facility is owned and operated by SRP and consists of Coronado Units 1 and 2, both of which are subject to the FIP. SRP uses hot-side electrostatic precipitators and wet flue gas desulfurization systems to control particulate matter (“PM”) and sulfur dioxide (“SO2”) emissions, respectively, and low-NOx burners (“LNB”) and overfire air (“OFA”) to control NOx emissions. SRP is constructing a selective catalytic reduction (“SCR”) system on Unit 2 that will begin operation prior to June 2014 pursuant to a consent decree that resolved allegations of noncompliance at Coronado with prevention of significant deterioration (“PSD”) requirements under the CAA. *U.S. Environmental Protection Agency v. Salt River Project Agricultural Improvement and Power District*, Case 2:08-cv-014790-JAT (D. Ariz. 2008) (“consent decree”).

On July 20, 2012, EPA published its proposed rule on regional haze implementation plan requirements for Coronado under the CAA. 77 Fed. Reg. 42834 (“Proposed Rule”). EPA proposed, *inter alia*, to approve the PM and SO2 BART determinations for Coronado in the Arizona state implementation plan (“SIP”), which set BART limits for those pollutants at 0.03
pounds per million British thermal units (“lb/mmBtu”) and 0.08 lb/mmBtu on a 30-day rolling average basis, respectively. *Id.* at 42851-52. Both the PM and SO₂ emission limits set forth in the Arizona SIP and the Proposed Rule were consistent with the consent decree. EPA also proposed, however, to impose, through a FIP, a NOₓ BART emission limit of 0.050 lb/mmBtu (on a rolling 30-boiler-operating-day average) at Unit 1 and an emission limit of 0.080 lb/mmBtu (on a rolling 30-boiler-operating-day average) at Unit 2. The NOₓ emission limit for Unit 2 set out in the Proposed Rule was consistent with the consent decree. *Id.* at 42864. The EPA-imposed limit in the Proposed Rule for both units presumed use of SCR plus LNB and OFA. *Id.*

In contrast, the Arizona SIP – which in this respect EPA proposed to disapprove – established NOₓ BART for Coronado Units 1 and 2 as an emission limit of 0.32 lb/mmBtu, which could be met with LNB and OFA alone and without use of SCR or other post-combustion control technology. *See id.* at 42842 Table 3.

On September 18, 2012, within the comment period on the Proposed Rule, SRP submitted comments that supported EPA’s proposed action regarding approval of the SIP’s provisions for PM and SO₂ BART requirements at Coronado. SRP also submitted extensive comments addressing flaws in EPA’s proposed NOₓ BART determination for Coronado. *See SRP Rulemaking Comments, EPA-R09-OAR-2012-0021-0048; see also Comments of the Arizona Utilities Group, EPA-R09-OAR-2012-0021-0058.* In its comments, SRP opposed EPA’s proposed BART limit for NOₓ, arguing that, for a wide range of reasons, that element of the Proposed Rule was contrary to the CAA and EPA’s rules and was unreasonable and arbitrary.

EPA’s Final Rule as applied to Coronado deviates from the Proposed Rule in a critical and unforeseeable respect. The Final Rule requires SRP to comply with a single NOₓ emission limit across Coronado Units 1 and 2 of 0.065 lb/mmBtu, using a novel approach to plantwide
averaging that differs significantly from the NOx-related provisions of the Proposed Rule and SRP’s rulemaking comments requesting the option of plantwide averaging. Had EPA provided SRP with adequate notice of EPA’s intended NOx BART limit and approach to plantwide averaging for Coronado, SRP could have explained why this element of the Final Rule is unworkable and inappropriate for Coronado. SRP is therefore filing this petition to address its specific objections to this aspect of EPA’s Final Rule. For the reasons described in Section II below, SRP requests that, in compliance with section 307(d) of the CAA, EPA promptly convene a proceeding for reconsideration, and issue a stay under the CAA, of this aspect of the Final Rule. Moreover, in Section III below, SRP explains why an administrative stay under the APA of the effectiveness of the Final Rule’s NOx BART requirements for Coronado is warranted and necessary.

II. The Final Rule’s Provisions Imposing a Mandatory 0.065 lb/mmBtu Plantwide NOx Emission Limit for Coronado Warrant EPA’s Reconsideration and Stay of the NOx BART FIP for Coronado Under the CAA.

In comments on the Proposed Rule, SRP, through the Arizona Utilities Group, requested that EPA “allow for the option of plantwide averaging at Apache, Cholla, and Coronado.” Comments of the Arizona Utilities Group at 37 (emphasis added); see also SRP Rulemaking Comments at page 4-5. EPA’s Final Rule, however, establishes a particular, novel type of plantwide averaging and, moreover, makes plantwide averaging mandatory rather than optional, as SRP had requested. The plantwide NOx limit that EPA’s FIP imposes – “0.065 lb/MMBtu determined as an average of the two units, based on a rolling 30-boiler-operating-day average,” 77 Fed. Reg. at 72515 – fails to provide Coronado with an adequate margin for compliance. This EPA failure is of central importance to the rule because EPA’s BART regulations specify that, to represent BART, an emission limit must be “achievable” at the individual source to which that
limit applies. 40 C.F.R. § 51.301 (definition of “BART”). Furthermore, the FIP sets out for the first time a novel compliance determination method for this plantwide average NOx limit that raises serious technical problems that further jeopardize Coronado’s ability to comply. As discussed below, the procedural and substantive deficiencies of the NOx BART FIP limit, announced for the first time in the Final Rule, require that EPA convene reconsideration proceedings and stay the NOx BART FIP for Coronado.

First, EPA’s decision to mandate plantwide averaging was not an element of the Agency’s proposed rule for Coronado. Moreover, SRP never requested a mandatory plantwide averaging requirement. On the contrary, SRP requested that EPA provide the option of plantwide averaging at an appropriate emission rate limit and using an appropriate averaging methodology so as to allow the flexibility that plantwide averaging can offer under the right circumstances. A mandatory plantwide limit at the level, and using the methodology, required by the Final Rule precludes that flexibility and likely will make compliance for Coronado more difficult than compliance under a unit-by-unit limit in some circumstances. For example, under the approach imposed by EPA in the Final Rule, compliance with the plantwide limit may not be achieved even if Unit 2 complies with its own consent decree emission limit on a unit-specific basis.

Second, EPA’s Final Rule states that Coronado’s plantwide 0.065 lb/mmBtu NOx limit “will provide a sufficient compliance margin for startup and shutdown events.” Id. at 72556. This is not the case. The 0.065 lb/mmBtu limit required by the FIP is a simple arithmetic average of the two emission rate limits that EPA included in the Proposed Rule for Coronado Units 1 and 2: 0.050 and 0.080 lb/mmBtu, respectively. EPA’s Final Rule acknowledges that it is appropriate for Coronado’s NOx BART determination for Unit 2 to reflect the 0.080
lb/mmBtu limit required in the Coronado PSD consent decree with EPA. Id. at 72527 (“we have taken into account … the existing consent decree” in setting the NOx BART limit for Coronado). The Final Rule states that the FIP NOx limit “take[s] into account … the need to accommodate startup and shutdown events.” Id. Yet EPA also acknowledges that a 0.050 lb/mmBtu NOx limit is not achievable on a 30-day rolling average basis if startup and shutdown events are included in the determination of compliance, as the FIP requires. Id.; see also id. at 72514, 72515, 72535, 72536, 72542, 72545, 72546, 72553, 72554. Accordingly, during the rulemaking, in response to SRP’s comments on the infeasibility of the proposed FIP’s emission rate limit for Coronado, EPA increased the required NOx emission rate limit for Apache Generating Station Units 2 and 3 (units that EPA recognizes are similar to the units at Coronado, see id. at 72535), from 0.050 to 0.070 lb/mmBtu in the Final Rule to allow for startup- and shutdown-associated emissions. Id.; see also Decl. of James M. Pratt ¶¶ 11, 12 (“Pratt Decl.”) (Exhibit 1 hereto). For Coronado to be able to comply with the FIP’s 0.065 lb/mmBtu plantwide limit, it would be required either to operate Unit 2 below 0.080 lb/mmBtu, which would be more stringent than and therefore inconsistent with Coronado’s consent decree, or to operate Unit 1 at or below a 0.050 emission rate, which EPA concluded is infeasible. Id. ¶ 9, 10. Because the plantwide emission rate limit in the FIP fails to provide Coronado with an adequate margin of compliance, EPA should stay the NOx BART FIP for Coronado and convene reconsideration proceedings on this issue.

Finally, the specific, unit-by-unit “30-day lookback” method imposed by the FIP for determining compliance with the FIP’s plantwide NOx limit is both novel and problematic. Id. ¶¶ 14-19. As EPA explains, the Final Rule

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2 See 70 Fed. Reg. 39104, 39164 (July 6, 2005) (“NSR[new source review]/PSD settlement agreements” may properly be relied upon for BART determinations).
establishes the compliance determination method such that when one unit is not operating, the emissions from its own preceding thirty boiler-operating-days will continue to be included in the 30-day rolling average. In the case of Coronado, for example, during periods when only one unit operates, this method allows the one operating unit to average out short-term emission spikes by using the most recent thirty boiler-operating-day value from the non-operating unit. Otherwise, averaging across units would not be possible during such periods, since the emissions value from the non-operating unit would be zero since it is not operating.

77 Fed. Reg. at 72527. Accordingly, compliance with the plantwide limit could be unattainable due to fictional emissions from a unit that is not currently operating because the limit must be calculated on a daily basis using separately derived 30-boiler-operating-day averages for each unit even if one, or both, of the units is offline. Pratt Decl. ¶ 19.

The NOx BART FIP for Coronado – including its 0.065 lb/mmBtu limit with no compliance margin for startup and shutdown conditions and with mandatory plantwide averaging using a novel unit-by-unit 30-day lookback approach – was not announced by EPA until publication of its Final Rule. Thus, no public notice or opportunity for comment was provided. Moreover, as SRP would have commented to EPA during the rulemaking if EPA had included this requirement in the Proposed Rule, these elements of the NOx BART FIP pose serious problems and could improperly result in unwarranted instances of noncompliance at Coronado. Thus, SRP’s objections to the FIP on these issues are of central relevance to the rule. Accordingly, EPA should promptly grant reconsideration of the Final Rule and stay the effectiveness of the FIP pursuant to CAA § 307(d).

III. EPA Should Stay the FIP and Toll the FIP’s Compliance Period Under the APA Pending Resolution of the Litigation.

As stated above, SRP respectfully requests that EPA grant an immediate administrative stay of the effective date of, and toll the compliance period for, the requirements of the FIP in the Final Rule, pending completion of litigation on the FIP, pursuant to the APA. As discussed
above, the FIP establishes a NOx BART emission limit for Coronado. SRP, as the owner and operator of Coronado, will suffer substantial and irreparable harm if this regulation goes into effect and is not stayed. In contrast, no significant harm is likely to result from a stay of the FIP. As described in greater detail below, because SRP’s pending legal challenge to the Final Rule is likely to succeed on the merits, and because a stay is in the public interest and necessary to prevent irreparable harm to SRP, EPA should grant this request.

As discussed above, EPA has two sources of authority by which it can grant a stay of the Final Rule – the CAA and the APA – and SRP requests that EPA take action under both. CAA section 307(d)(7)(B), which grants the Administrator authority to convene reconsideration proceedings, also authorizes the Administrator to stay the effectiveness of a rule during its reconsideration “for a period not to exceed three months.” 42 U.S.C. § 7607(d)(7)(B). This provision provides the Administrator wide latitude to grant a stay in conjunction with a determination to convene reconsideration proceedings, and, in order to ensure the orderly and thoughtful proceeding on administrative reconsideration that is necessary and warranted under section 307(d)(7)(B), EPA should exercise its CAA stay authority here upon a grant of reconsideration.

Section 10(d) of the APA also grants EPA authority to stay the Final Rule: “When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review.” 5 U.S.C. § 705 (2010). Although this provision on its face gives agencies broad authority to grant stays when “justice so requires,” agencies, in implementing this provision, often refer to criteria governing preliminary injunction requests before federal courts. Corning Savings & Loan Ass’n v. Fed. Home Loan Bank Bd., 562 F. Supp. 279, 280 (E.D. Ark. 1983) (“the test to be applied as to whether a stay [pursuant to 5 U.S.C. § 705] should be entered
is the same as that which applies to requests for preliminary injunctions"). As the Supreme Court has stated, “[a] plaintiff seeking a preliminary injunction must establish that he is likely to succeed on the merits, that he is likely to suffer irreparable harm in the absence of preliminary relief, that the balance of equities tips in his favor, and that an injunction is in the public interest.” *Winter v. Natural Resources Defense Council, Inc.*, 555 U.S. 7, 20 (2008); see also, *e.g.*, *Am. Trucking Ass’ns, Inc. v. Los Angeles*, 559 F.3d 1046, 1052 (9th Cir. 2009); *Washington Metropolitan Area Transit Comm’n v. Holiday Tours, Inc.*, 559 F.2d 841, 843 (D.C. Cir. 1977).

Moreover, an agency or a court reviewing a request for a stay is not to review each of these factors in a rigid or isolated manner. On the contrary, the United States Court of Appeals for the Ninth Circuit, for instance, has adopted a “sliding scale” approach to the criteria for preliminary injunctions. “Under this approach, the elements of the preliminary injunction test are balanced, so that a stronger showing of one element may offset a weaker showing of another.” *Alliance for the Wild Rockies v. Cottrell*, 632 F.3d 1127, 1131 (9th Cir. 2011).

For the reasons described below, SRP satisfies each of the stay factors applicable under the APA. EPA should therefore grant a stay of the FIP, as it applies to Coronado, not only pursuant to the CAA upon a grant of SRP’s request for reconsideration, but also pursuant to the APA pending completion of judicial review of the Final Rule.

A. **SRP Is Likely To Succeed on the Merits in Its Challenge to the Final Rule.**

With respect to its partial disapproval of Arizona’s SIP and its promulgation of a FIP, EPA’s Final Rule is seriously flawed in a number of critical respects, and SRP’s challenge to the rule is likely to succeed on the merits. EPA’s errors stem from fundamental legal misinterpretations and improper application of its own rules governing BART determinations, as well as seriously flawed procedural and technical foundations for the SIP-disapproval and FIP elements of the Final Rule. EPA should take into account the nature, number, and severity of the
flaws SRP has identified as the Agency evaluates this factor. Indeed, even if EPA believes it may ultimately be able to support these elements of the Final Rule on the merits after judicial review, the merits arguments SRP has identified undoubtedly raise, at the very least, “serious questions going to the merits” and satisfy the stay test applied by the Ninth Circuit. *Id.* (internal quotations omitted).

1. **State primacy under the CAA visibility program renders the FIP unlawful.**

   In the Final Rule, EPA rejects Arizona’s NOx BART determination for Coronado (an emission rate of 0.32 lb/mmBtu based on LNB and OFA, 77 Fed. Reg. at 42842 Table 3), and imposes its own NOx BART emission limit of 0.065 lb/mmBtu determined as an average of the emissions from the two units, based on a rolling 30-boiler-operating-day average, requiring installation and operation of SCR on both units, 77 Fed Reg. at 72515 Table 1. EPA’s Final Rule in this respect unlawfully abrogates state authority under the CAA and is therefore unlawful.

   The CAA and EPA’s regional haze rules provide that states, not EPA, are to exercise the primary authority in implementing the regional haze program, including the determination of BART. *See, e.g.*, CAA § 169A(b)(2)(A), (g)(2), 42 U.S.C. § 7491(b)(2)(A), (g)(2) (providing that the states, not EPA, are generally to determine which sources are subject to BART and to determine BART emission limits for those sources); 40 C.F.R. § 51.308(e) (same). The primacy of the states in this regard is a central feature of the CAA, as recognized by the D.C. Circuit in *Am. Corn Growers Ass’n v. EPA*, 291 F.3d 1, 8 (D.C. Cir. 2002) (holding that key aspects of EPA’s 1999 regional haze rules were “inconsistent with the Act’s provisions giving the states broad authority over BART determinations”). Indeed, EPA’s BART rules, as amended by EPA in 2005 in response to the *Corn Growers* decision, and the BART Guidelines promulgated by
EPA at the same time, emphasize that states have exceptionally broad discretion in setting BART for individual sources. See, e.g., 70 Fed. Reg. at 39,105-06. Arizona considered each of the BART factors in making its BART determination, and it stated that determination in its SIP, which is all the law requires Arizona to do.

Thus, EPA had an obligation to approve the state’s NOx BART determination for Coronado – an action that would have removed any authority for EPA to promulgate a FIP – and EPA’s decision to impose an alternative, much more stringent plan in contravention of the policy choice adopted by the state is contrary to the CAA.

2. EPA’s final NOx BART FIP fails to recognize that Coronado’s PSD-related consent decree should be deemed to be at least as stringent as BART.

As noted above and as acknowledged by the Final Rule, Coronado is subject to a consent decree negotiated with EPA to resolve alleged violations of PSD requirements at Coronado. That consent decree establishes a requirement that Coronado install and operate SCR on one of its units and achieve an emission rate of 0.080 lb/mmBtu at that unit no later than June 1, 2014. SRP chose to comply with this requirement at Unit 2 and is installing an SCR to meet this compliance deadline. The consent decree also requires Coronado to comply with a plantwide emission limit of 7,300 tons of NOx per year, which translates to an effective emission rate of approximately 0.20 lb/mmBtu for Coronado, a plantwide limit that is more stringent than the presumptive BART limit for the type of units present at Coronado. See 70 Fed. Reg. at 39135.3

3 In the Final Rule, EPA asserts that it did not consider the presumptive NOx BART limit applicable to Coronado because the Coronado units “have access to and have historically burned both bituminous and sub-bituminous coal,” which, according to EPA, means that “there is no single presumptive NOx limit that applies” to Coronado. 77 Fed. Reg. at 72529. This argument is unpersuasive. The presumptive NOx limit applicable to Coronado is either 0.39 or 0.23 lb/mmBtu depending on whether it is burning bituminous or subbituminous coal, and both of those presumptive limits are higher than the plantwide emission rate provided for in the Coronado consent decree. 70 Fed. Reg. at 39172, Table 1. The critical fact, which EPA
EPA’s BART Guidelines state that emission limits in consent decrees that are entered into to resolve alleged PSD violations, such as the Coronado consent decree, should generally be deemed to satisfy any BART requirements. 70 Fed Reg. at 39164 (requirements in “NSR/PSD settlement agreements” generally satisfy BART requirements). This is unsurprising. PSD, which requires new sources to install “best available control technology” (or “BACT”) is generally more stringent than BART, which applies to existing facilities on which emission controls would have to be retrofit. Indeed, EPA recognizes the principle that BACT is more stringent than BART in the Final Rule. 77 Fed Reg. at 72527-28 (“we disagree with the … assertion that emission limits associated with BART must meet” a BACT NOx limit).

EPA’s Final Rule should have followed the BART Guidelines and – assuming for the sake of argument that EPA had any basis for disapproving the SIP’s BART determination for Coronado (a basis that EPA did not have) – EPA should have accepted Coronado’s PSD-related consent decree NOx limits for the plant as satisfying NOx BART requirements for Coronado.

3. EPA improperly determined emission control costs, rendering its BART determination invalid.

A BART determination for a particular facility requires consideration of emission control costs. In assessing costs, EPA is required to take into account site-specific factors that will impact costs. See Corn Growers, 291 F.3d at 6-7 (BART determinations must be made on a “source-specific basis,” including consideration of costs that are source-specific); 70 Fed. Reg. at 39127, 39166 & n.15. EPA’s 2005 BART rules properly reflect the site-specific nature of the BART analysis. For example, those rules state that “one or more of the available control options disregards in the FIP, is that for all coal-fired boilers (except cyclone units, which are not present at Coronado), the presumptive NOx BART limits established by EPA are based on combustion controls only, not the post-combustion SCR controls that the FIP improperly mandates. Id. at 39134-36, 39171-72.
may be eliminated from consideration because they are demonstrated to be technically infeasible or to have unacceptable energy, cost, or non-air quality environmental impacts on a case-by-case (or site-specific) basis.” *Id.* at 39164; *see also id.* at 39166 (“[t]he cost analysis should … take into account any site-specific design or other conditions … that affect the cost of a particular BART technology option.”).

EPA’s BART determination for Coronado is premised on significantly underestimated costs for the installation and operation of SCR at that facility. A correct cost assessment, such as the one relied on by Arizona in making its BART determination, would demonstrate that SCR cannot be BART for Coronado. Because BART determinations require a site-specific analysis, SRP based the control cost estimates for Coronado that were included in its rulemaking comments on actual cost data derived from the completed installation of LNB/OFA on both units at Coronado and costs expended thus far related to the significant progress toward completing the installation of SCR on Unit 2 at Coronado. These data show that the actual costs incurred are much higher than the costs used by EPA to justify its BART determination. *See SRP Rulemaking Comments* at pages 6-1 to 6-15.

In addition, in promulgating its FIP, EPA improperly relied on emission control cost information from the Integrated Planning Model (“IPM”), which EPA acknowledges is not source-specific information. *See 77 Fed. Reg.* at 72528, 72530. It appears that this reliance on generic IPM cost information by EPA is unprecedented in a BART application. EPA cites nothing from its own BART rules or BART Guidelines that authorizes or contemplates that EPA could properly rely on this type of cost information, and SRP is aware of nothing that authorizes EPA to do so. In any event, the data inputs EPA selected in implementing IPM are incorrect given the site-specific characteristics of Coronado. This error by EPA significantly
underestimated the actual NOx control costs that should have been used in EPA’s analysis. As mentioned above, SRP is in the final stages of completing the Coronado Unit 2 SCR installation, and based on actual incurred costs, SRP estimates that EPA’s IPM capital cost estimate for Unit 1 is equal to approximately 55 percent of what the actual Unit 1 SCR cost would be. SRP Rulemaking Comments at page 6-8.

Moreover, EPA’s insistence on using cost information from IPM (i.e., non-source-specific, highly generic cost information) to attempt to support its improperly stringent NOx emission limit for Coronado is in irreconcilable conflict with EPA’s refusal to use other information from the same IPM that supports a higher NOx emission limit for Coronado (i.e., EPA’s IPM-based determination that 0.06 lb/mmBtu is the lowest NOx emission rate that can reasonably be required as a retrofit application for a coal-fired electric generating unit). See 77 Fed. Reg. at 72528. EPA cannot have it both ways: If, as EPA contends, using IPM is “not appropriate,” id. – because too generic – for use in determining achievable emission rates, then it is inappropriate for EPA to rely on IPM assumptions for its BART cost estimates. For these reasons, the Final Rule is invalid with respect to its disapproval of the state’s NOx BART determination and its promulgation of a NOx BART FIP.

4. EPA improperly rejected Arizona’s calculations of the visibility benefits expected to result from potential BART controls.

The Final Rule’s NOx BART determination for Coronado is premised on an improper assessment of the projected visibility benefits of deploying SCR at the facility and an unwarranted rejection of the State of Arizona’s visibility impacts analysis. Arizona assessed visibility impacts in Class I areas potentially affected by Coronado’s emissions by considering a visibility index, “defined as the average of the visibility benefits at the closest nine Class I areas,” including “the five areas with the highest baseline impacts.” 77 Fed. Reg. at 42850.
EPA’s proposed and final rules acknowledged that this approach provided useful information and that it could be used to support a BART determination. *Id.*; 77 Fed. Reg. at 72519. Nevertheless, EPA rejected the state’s visibility assessment as inadequate because, according to EPA, it does not take sufficient account of the effects at the area most impacted by Coronado’s emissions. *Id.* The BART Guidelines suggest the “maximum impact area” approach to assessing visibility impacts as one possible method. That suggestion, however, is in no way binding on the states. On the contrary, the states have broad discretion to consider whatever visibility impact analysis they deem most relevant. *See, e.g.,* 70 Fed. Reg. at 39170 (BART Guidelines describing an approach states “may” use to assess visibility impacts, but emphasizing that states “have flexibility in setting absolute thresholds, target levels of improvement, or *de minimis* levels since the deciview improvement must be weighed among the five [BART] factors, and [states] are *free to determine the weight and significance to be assigned to each factor*”) (emphases added). Nothing in the BART rules or Guidelines requires a particular visibility-impacts assessment approach; instead, the Guidelines recognize that states have broad “flexibility” and discretion in this matter. EPA failed to provide an adequate basis for rejecting Arizona’s visibility impacts assessment for Coronado, and it therefore had no basis for rejecting the state’s BART determination because of Arizona’s consideration of this factor.

Moreover, despite EPA’s assertion that Arizona’s SIP is unapprovable because, according to EPA, the state did not show that it considered “particular area improvements” with respect to Coronado, EPA’s NOx BART FIP for Coronado itself places no significant emphasis on an individual-area analysis and instead relies on a “cumulative” approach, which involves adding the small visibility impacts in each Class I area together, an approach that itself obscures maximum visibility impacts at individual areas. *See* 77 Fed. Reg. at 72532. Consideration of
cumulative visibility impacts improperly manipulates the assessment and weighing of the BART factors and inappropriately favors the most expensive emission control technologies. Reliance on this methodology is therefore unsound and renders EPA’s NOx FIP for Coronado unlawful.

5. **EPA’s FIP fails to recognize that the NOx BART limit EPA has imposed is infeasible and therefore unachievable.**

As described above, the Final Rule’s plantwide NOx limit of 0.065 lb/mmBtu effectively requires Coronado Unit 1 to continuously meet a 0.050 lb/mmBtu NOx emission limit. Such a limit, especially one that includes emissions associated with periods of startup and shutdown, cannot be achieved at Coronado. In a number of recent rulemaking actions, including its promulgation of the BART FIP provisions for NOx emissions from the Apache Generating Station ("Apache") included in the Final Rule at issue here, EPA has acknowledged that a 0.050 lb/mmBtu NOx emission rate limit is unachievable at a coal-fired unit as a retrofit when applying a 30-day averaging period – and thus cannot be BART for such a unit. See 40 C.F.R. § 51.301 (definition of “BART”). Thus, as promulgated by EPA, the FIP’s BART limit for Coronado is unlawful.

For instance, as part of the 2010-2011 rulemaking that culminated in promulgation of the Cross-State Air Pollution Rule ("CSAPR"), EPA determined that a NOx emission rate lower than 0.06 lb/mmBtu is not achievable through retrofit of SCR on coal-fired electric generating units. EPA, “Transport Rule Engineering Feasibility Response to Comments,” EPA-HQ-OAR-2009-0491, at 13 (July 2011) (discussing “SCR Capability” and concluding that “current technology is capable of removing up to 90% of incoming NOx (subject [to] a floor limit of 0.06 lbm [sic] NOx /MMBtu) on a continuous basis”). In a Notice of Data Availability for the proposed version of CSAPR, EPA described a methodology for calculating emission allowance allocations under the rule that was based on a “well-controlled emission rate of … 0.06
lbs/mmBtu for NOx.” 76 Fed. Reg. 1109, 1115 (Jan. 7, 2011). As EPA explained in that notice, this 0.06 lb/mmBtu rate “represent[s] the lowest annual emission rate[] assumed achievable when state-of-the-art pollution control technologies are installed at coal units in the IPM modeling” that EPA used to support that rule. Id. EPA further explained that a 0.06 lb/mmBtu NOx emission rate is the “floor rate[] used in the IPM modeling and … [is] intended to reflect the lower bound of emission rates that suppliers are willing to guarantee when installing state-of-the-art pollution control equipment (selective catalytic reduction (SCR) ….).” Id. at 1115 n.3.

EPA similarly recognized that a 0.050 lb/mmBtu emission rate was unachievable for coal-fired electric generating units in recent regional haze rulemakings with respect to North Dakota, South Dakota, and Colorado. 76 Fed. Reg. 58570 (Sept. 21, 2011); 77 Fed. Reg. 24845 (Apr. 26, 2012); 77 Fed. Reg. 76871 (Dec. 31, 2012). Further, in the Final Rule at issue here, EPA acknowledged that the very similar units at Coronado and Apache “cannot achieve an SCR emission rate of 0.050 lb/MMBtu on rolling 30-day average.” 77 Fed. Reg. at 72535. As a result, EPA increased the NOx emission limit for Apache to 0.070 lb/mmBtu in the Final Rule but failed to make a similar necessary adjustment for Unit 1 at Coronado.

In its Final Rule, EPA argues that it would have been inappropriate to rely in this rulemaking action on the Agency’s previous findings. It argues, for instance, that EPA’s CSAPR-related finding should be disregarded because it was based on “sector-wide modeling assumptions” that differ from the site-specific analysis required for BART. 77 Fed. Reg. at 72528. But EPA’s past site-specific determinations, discussed above, show that EPA acted arbitrarily and unreasonably in refusing to make a similar site-specific determination with respect to Coronado.
6. EPA’s Final Rule contains elements that were not adequately noticed in the Proposed Rule and that render the Final Rule infeasible.

EPA adopted critically important elements of its Final Rule without adequate public notice, also rendering the rule invalid. With respect to Coronado, as noted above, EPA, for the first time in the Final Rule and without prior public notice or opportunity for comment, described its intention to mandate “bubbling” across the Coronado units, notwithstanding SRP’s request that SRP be given the option of plantwide averaging. Additionally, the plantwide limit EPA included in its Final Rule, as described above, provides no margin of compliance for Coronado. Finally, EPA for the first time in the Final Rule described the methodology by which it would require averaging across the Coronado units, including a novel 30-day lookback approach that will not be feasible at Coronado. The infeasibility of the FIP’s approach is detailed in the attached Declaration of James M. Pratt at ¶¶ 8-23.

Because each of these issues was inadequately noticed by EPA for public comment at the time of proposal and because the Final Rule is inadequately supported in critical respects as described above, the FIP aspects of EPA’s Final Rule are seriously flawed and should be stayed and invalidated.

B. SRP Will Suffer Irreparable Harm in the Absence of a Stay.

EPA’s Final Rule requires SRP to complete installation of additional emission controls and to comply with the FIP’s NOx emission limit for Coronado by December 5, 2017. This compliance deadline places SRP in an untenable position. SRP cannot wait until its judicial challenge to the Final Rule has been finally determined before having to incur significant expenditures that would be necessary to ensure that Coronado is retrofitted with operational SCR at both units by December 5, 2017, as the FIP requires. On the contrary, SRP must undertake near-term steps to procure the goods and services necessary to meet the FIP’s
compliance timeframe. The result is that, absent a stay, SRP will have to incur significant costs – costs that could not be recovered from EPA – due to the FIP, even if the FIP is ultimately held to be invalid. Thus, SRP will suffer irreparable harm in the absence of a stay.

To evaluate whether an injury amounts to “irreparable harm” of the sort warranting a stay of an agency rule, courts often look to three factors: (1) the substantiality of the injury alleged; (2) the likelihood of its occurrence; and (3) the adequacy of the proof provided. Cuomo v. Nuclear Regulatory Commission, 772 F.2d 972, 977 (D.C. Cir. 1985). As discussed below, the facts presented here demonstrate that SRP will suffer irreparable harm if a stay of the FIP’s effective date and a concomitant tolling of the FIP’s compliance period are not granted.

SRP will suffer substantial injury in the absence of a stay. As described in the attached Pratt Declaration, because of the FIP, SRP must immediately begin to prepare for the installation of SCR at Coronado Unit 1, a project that SRP currently estimates to cost a total of at least $105 million. Pratt Decl. ¶ 24. To meet the FIP compliance deadline in the Final Rule, SRP must now begin expending significant sums for permitting, analysis of compliance feasibility and options, and preliminary planning and design work. These efforts will require both significant internal staff commitment and the retention of outside experts, at a cost currently projected to total approximately $5,850,000 within the next 12 to 24 months. Id. SRP will be required to complete upfront engineering and modeling (estimated to cost approximately $850,000) in 2013; complete the permit application process and begin ordering major equipment in 2014 (estimated to cost approximately $5 million in that year); and, in 2015 through 2017, complete construction and tie-in work. Id.

SRP estimates that the earliest likely period for completion of resolution of its petition for reconsideration and its appeal to the Ninth Circuit is late 2014, although it is possible that
litigation on the appeal could continue beyond that timeframe. It is thus very likely that SRP will incur approximately $5 million or more in expenses associated with the Final Rule before the petitions for review of the Final Rule are resolved. If resolution does extend beyond late 2014, then SRP clearly will begin to incur even more significant expenditures associated with major equipment purchases that would be necessary to meet the current FIP compliance deadline.

Courts have recognized that, in the ordinary run of cases, monetary injuries generally do not constitute irreparable harm because they can later be recovered as damages at the conclusion of litigation. See, e.g., Sampson v. Murray, 415 U.S. 61, 90 (1974) (“the temporary loss of income, ultimately to be recovered, does not usually constitute irreparable injury”); California ex rel. John Van de Kamp v. Tahoe Regional Planning Agency, 766 F.2d 1316, 1319 (9th Cir. 1985) (“financial injury will not constitute irreparable harm if adequate compensatory relief will be available in the course of litigation”). Courts have also recognized the principle that if there is no opportunity for compensation though litigation, then monetary injury should be considered irreparable harm. See, e.g., California Pharmacists Ass’n v. Maxwell-Jolly, 563 F.3d 847, 852 (9th Cir. 2009) (holding that monetary injury is irreparable where sovereign immunity prevents recovery), vacated and remanded on other grounds, Douglas v. Independent Living Ctr. of Southern California, Inc., 132 S. Ct. 1204 (2012); see also Arizona Hosp. & Healthcare Ass’n v. Betlach, 865 F. Supp. 2d 984, 998 (D. Ariz. 2012) (continuing to apply California Pharmacists’ irreparable harm holding after Douglas); Conte v. Transglobal Assets, 2012 WL 4092717 at 1 (D. Nev. Sept. 17, 2012) (same).

No mechanism is available to SRP (or its customers) to recover their costs from EPA or the federal government generally in the event that the SIP-disapproval and FIP elements of the
Final Rule are held to be unlawful. Accordingly, there is no adequate remedy at law, and the injuries that SRP faces as a result of EPA’s action are irreparable.

_It is very likely that SRP will suffer substantial harm in the absence of a stay of the effective date of the FIP._ The harm that SRP will suffer during the pendency of its appeal is in no way speculative. SRP is certain to incur significant costs during the appeal and, as noted above, SRP already has begun to incur costs for upfront engineering and modeling. Throughout 2013 and 2014, additional costs will be incurred for permitting and preliminary design efforts. Those costs cannot be recovered from EPA regardless of the outcome of the litigation.

_SRP has submitted adequate proof of substantial harm._ SRP has submitted a declaration from James M. Pratt, SRP Senior Director of Baseload Generation, as factual support for its request for a stay of the effective date of, and a tolling of the compliance schedule in, the FIP. Mr. Pratt has more than 28 years of experience in the electric utility industry and currently oversees the operation of SRP’s coal-fired generation facilities. Mr. Pratt’s declaration explains the flaws in the Final Rule, the infeasibility of maintaining continuous compliance with the FIP’s NOx limit as promulgated, and the costs and other harm to SRP if the FIP is not stayed. Thus, there is substantial evidence to support SRP’s entitlement to a stay of the effective date of the FIP and concomitant tolling of the FIP’s compliance period pending appeal.

C. **The Balance of Equities Favors Granting SRP’s Stay Request, and Granting a Stay Is in the Public Interest.**

The balance of equities and the public interest strongly support issuance of a stay of the SIP-disapproval and FIP elements of the Final Rule immediately and pending completion of judicial review. The harm to SRP if a stay is not granted and the public interest weigh heavily in favor of granting this stay request.
As discussed above, SRP will be required to incur substantial costs for SCR installation due to the FIP long before SRP’s legal challenge to the FIP is likely to be resolved. This will involve substantial financial expenditures and the deployment of significant efforts in response to the FIP’s requirements and compliance schedule.

In addition, failure to stay the FIP would fail to address a considerable injury to state sovereignty, a factor weighing heavily in favor of granting this request and confirming that a stay is in the public interest. As described above, the states are given an especially important role under the visibility program of the CAA. The D.C. Circuit has emphasized the states’ decision-making and policy-setting primacy under the regulatory scheme enacted by Congress, see Corn Growers, 291 F.3d at 5-9, and EPA’s underlying BART rules acknowledge that the CAA gives states exceptionally broad authority and discretion in determining BART for individual facilities. Here, Arizona properly exercised its authority under the law. Nevertheless, EPA improperly disapproved critical elements of Arizona’s SIP and instead promulgated a FIP that contradicts the state’s policy decisions on the basis that EPA weighs the BART factors differently than Arizona did. Accordingly, the injury to the public interest and the harm to Arizona’s sovereign rights in the absence of a stay strongly support the conclusion that EPA should grant this stay request. See, e.g., Coal for Econ. Equity v. Wilson, 122 F.3d 718, 719 (9th Cir. 1997) (“a state suffers irreparable injury whenever an enactment of its people or their representatives is enjoined”); Kansas v. United States, 249 F.3d 1213, 1227-28 (10th Cir. 2001) (emphasizing the importance of Kansas’s claims of violations of state sovereignty in determining that a preliminary injunction was warranted).

On the other hand, a stay during the pendency of judicial review will not result in harm to EPA. The Agency’s FIP, if ultimately determined to be lawful, would become effective at the
conclusion of litigation. EPA will not, as a result of staying the rule, fall out of compliance with any of its statutory or regulatory obligations. In short, the Agency would not be injured by exercising a legitimate statutory authority to stay the effective date of its regulation pursuant to the APA.

Similarly, any harm to the public interest that might result from staying the Final Rule would be minimal. Coronado’s emissions are already well-controlled, and its emissions’ contribution to visibility impairment is minor. Indeed, visibility impairment – a transitory condition that is entirely aesthetic in nature – was recognized by Congress, in enacting the CAA’s visibility provisions, as an environmental issue that the nation should appropriately address under a “reasonable progress” standard that contemplates gradual emission reductions over a decades-long period. CAA § 169A(a)(4), (b)(2); 42 U.S.C. § 7491(a)(4), (b)(2). EPA’s own regulations reflect that policy judgment, providing a 2064 date for meeting the “goal” of natural visibility conditions, a timeframe for action that is itself nonbinding and is, in fact, subject to considerable flexibility and time extensions. 40 C.F.R. § 51.308(d)(1)(i)(B), (d)(1)(ii). The nature of the regulatory program at issue, and the flexibility that Congress provided regarding the timing of implementation of emission reductions, should inform EPA’s consideration of this stay request.

Moreover, the FIP is not directed at prevention or mitigation of adverse public health impacts. The courts have emphasized the significance of public health impacts in determining whether preliminary injunctions to preserve the status quo are warranted. See, e.g., Tate Access Floors, Inc. v. Interface Architectural Resources, Inc., 279 F.3d 1357, 1364 (Fed. Cir. 2002) (noting the absence of a public health threat as a significant factor favoring a preliminary injunction). The national ambient air quality standards are the mechanism Congress and EPA
use under the CAA to address public health threats from “criteria pollutants” such as NOx and SO2; those public-health-based standards are in no way at issue here.

Finally, the grant of a stay and the outcome of SRP’s challenge to the FIP will not determine whether Coronado will be required to comply with BART obligations that are properly promulgated pursuant to the CAA. The litigation will resolve whether EPA had a factually and legally valid basis for disapproving Arizona’s BART determination and for substituting its own BART determination and requirements as imposed by the FIP. If SRP is forced to undertake efforts to comply with EPA’s FIP prior to judicial resolution of that central question, the amount of money that SRP will have to spend, and the progress it will be forced to make toward installation of SCRs at Coronado, could effectively prevent Arizona’s conflicting BART determination from ever being given effect, even if a court ultimately overturns the FIP and holds that EPA lacked adequate justification and basis for disapproving the SIP’s NOx BART determinations and promulgating the FIP. In the meantime, Coronado will in any event continue to operate its existing emission controls, ensuring that air quality will not degrade. Moreover, SRP will continue with its installation of SCR at Coronado Unit 2 in compliance with its consent decree obligations. In other words, a stay will not release Coronado from any already-effective emission controls or from its consent decree obligations to reduce its emissions even further, and will not excuse SRP from compliance with properly determined BART requirements.

IV. Conclusion

For all of the foregoing reasons, EPA should promptly grant SRP’s petition for administrative reconsideration and convene a proceeding for reconsideration of the parts of EPA’s Final Rule addressed herein. Further, EPA should immediately stay the effectiveness of
those parts of the rule pending EPA’s reconsideration in accordance with this petition pursuant to section 307(d) of the CAA and during the pendency of litigation pursuant to the APA.
Exhibit 1

Declaration of James M. Pratt
DECLARATION OF JAMES M. PRATT
IN SUPPORT OF PETITION OF SALT RIVER PROJECT AGRICULTURAL
IMPROVEMENT AND POWER DISTRICT FOR PARTIAL RECONSIDERATION OF
FINAL RULE AND STAY OF EFFECTIVE DATE OF
FEDERAL IMPLEMENTATION PLAN

I, James M. Pratt, having first been duly sworn upon my oath, declare and state as
follows:

1. My name is James M. Pratt and I am the Senior Director of Baseload Generation
for Salt River Project Agricultural Improvement and Power District ("SRP"). My business
address is POB002, 6504 East Thomas Road, Scottsdale, Arizona 85251-6008. I am competent
to testify concerning the matters in this declaration. I received a Bachelor of Science degree in
Mechanical Engineering from Montana State University in 1983. I have more than 28 years of
experience in the electric utility industry. I have held a variety of management positions at SRP
in engineering, maintenance and operations at several gas and coal generation facilities, as well
as transmission planning.

2. In my current position with SRP, I am responsible for the operation of two coal
generation facilities operated by SRP – the Coronado Generating Station ("Coronado") and the
Navajo Generating Station. I also represent SRP’s interests with respect to the other coal
generation facilities in which SRP holds an interest but which are operated by other utilities. I
also oversee engineering support for SRP’s generation assets and the construction of generation-
related major projects, such as emission control improvements.

3. I served as the lead technical representative for the negotiation of a consent decree
entered into with EPA to resolve alleged violations of Prevention of Significant Deterioration
("PSD") requirements under the Clean Air Act at Coronado. After extensive negotiations with
EPA, a consent decree was entered by the U.S. District Court for the District of Arizona on August 12, 2008. This consent decree resolved alleged PSD violations for both Coronado units. *U.S. Environmental Protection Agency v. Salt River Project Agricultural Improvement and Power District*, Case 2:08-cv-014790JAT (D. Ariz. 2008) ("consent decree") (Attachment A). To comply with the consent decree, SRP has already installed low NOx burners ("LNB") with overfire air ("OFA") systems, and wet flue gas desulfurization ("WFGD") equipment on both units at Coronado, and is in the final stages of completing the installation of selective catalytic reduction ("SCR") equipment on Unit 2.

4. This declaration is submitted in support of SRP’s petition for partial reconsideration of the final rule issued by the U.S. Environmental Protection Agency ("EPA" or "Agency"), titled “Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Final Rule,” 77 Fed. Reg. 72512 (December 5, 2012) ("Final Rule"), and for a temporary stay of the effective date of the federal implementation plan ("FIP") promulgated as part of the Final Rule. SRP is challenging certain elements of EPA’s best available retrofit technology ("BART") determination affecting Coronado and seeks a stay of the effective date of the FIP for Coronado pending administrative reconsideration and a litigation appeal of that portion of the Final Rule.

5. SRP is a political subdivision of the State of Arizona that provides retail electric services to more than 950,000 residential, commercial, industrial, agricultural and mining customers in a 2,900 square mile area in Arizona. SRP operates or participates in 11 major power plants and numerous other generating stations, including coal, nuclear, natural gas and renewable sources, such as hydroelectric, solar, wind and geothermal.
6. SRP’s load responsibility peak demand was over 7,072 megawatts (“MW”) on August 24, 2011. SRP’s current generation portfolio has a combined capability of approximately 7,874 net-MW. In 2012, coal-fired generation represented approximately 37 percent of SRP’s total generation capability, but produced almost 59 percent of its retail energy requirements.

7. Coronado is a 773 net-MW coal-fired, steam electric generating station located near St. Johns, Arizona. Coal is provided to the plant from the Powder River Basin in Wyoming. Upon completion of the installation of additional emission controls required under the consent decree, including installation of SCR on Unit 2 by June 2014, the Coronado units will have the following emission controls in place:

   Unit 1 – LNB with OFA; WFGD System; Hot-Side Electrostatic Precipitator (“ESP”)

   Unit 2 – SCR; LNB with OFA; WFGD System; Hot-Side ESP

8. The Final Rule mandates that SRP must attain a nitrogen oxide (“NOx”) emission limit of 0.065 pounds per million British thermal units (“lb/mmBtu”) for Coronado, determined as an average of Coronado Units 1 and 2, based on a rolling 30-boiler-operating-day (“BOD”) average. The established emission limit is infeasible because it fails to provide an adequate compliance margin for Coronado to maintain continuous compliance.

9. In setting the plantwide average NOx emission limit in the FIP, EPA stated the Agency did not require a NOx emission limit for Coronado Unit 2 that is more stringent than 0.080 lb/mmBtu in recognition of the work already performed by SRP to meet the NOx limit established in the 2008 consent decree for the plant. 77 Fed. Reg. at 72556. Because EPA retained an effective emission limit of 0.080 lb/mmBtu on a rolling 30-BOD average for Unit 2, as a practical matter, Coronado Unit 1 must meet an effective limit of 0.050 lb/mmBtu on a
rolling 30-BOD average to maintain compliance with the plantwide NOx emission limit of 0.065 lb/mmBtu.

10. EPA acknowledged that the individual Coronado units cannot achieve a NOx emission rate of 0.050 lb/mmBtu on a rolling 30-BOD average based on the Agency’s review of the analysis provided by SRP during the public comment period on the Proposed Rule. 77 Fed. Reg. at 72535. EPA further concluded that it is appropriate to provide a compliance margin for periods of startup and shutdown when establishing a rolling 30-BOD average BART emission limit. Id.

11. During the public comment period on EPA’s Proposed Rule, Arizona Electric Power Cooperative (“AEPCO”) did not submit a technical analysis regarding the achievability of a rolling 30-day average NOx BART emissions limit of 0.050 lb/mmBtu at Apache Generating Station (“Apache”) Units 2 and 3. In the absence of such an analysis, EPA applied the results of the feasibility analysis conducted by SRP for the Coronado units, as the boiler design of the affected AEPCO units is almost identical to that of the affected Coronado units. After reviewing the SCR system analysis provided by SRP, EPA finalized a rolling 30-BOD average NOx BART emissions limit of 0.070 lb/mmBtu for Apache Units 2 and 3 as a “bubble” across these two units. 77 Fed. Reg. at 72535. EPA stated that the magnitude of the increase from the proposed individual unit limits of 0.050 lb/mmBtu was appropriate to accommodate emissions from startup and shutdown events, as well to provide AEPCO a sufficient measure of operational flexibility as a small entity. Id.

12. As EPA acknowledged, there are several important similarities between Apache Units 2 and 3 and Coronado Units 1 and 2. Specifically, all four of these units:

   a. Are the same boiler type (Riley turbo);
b. Were constructed and placed into operation at approximately the same
time (1979-1980);

c. Have access to, and potentially could use, a bituminous and sub-
bituminous coal blend; and

d. Exhibit a greater number of startup and shutdown events than coal-fired
units used more consistently as baseload generation.

77 Fed. Reg. at 72535. Despite recognizing the similarities between the Apache and Coronado
units and increasing the emission limit for Apache to reflect the infeasibility of complying with a
0.050 lb/mmBtu limit on a rolling 30-BOD average, EPA failed to provide an equivalent
compliance margin to accommodate startup and shutdown events for Coronado Unit 1.

13. The Final Rule does not provide an adequate margin of compliance for Coronado
Unit 1. Even new, state-of-the-art facilities have not been required to show continuous
compliance with a 0.050 lb/mmBtu NOx emission rate on a rolling 30-BOD average basis. See
RMB Consulting & Research, Inc., Technical Memorandum Regarding Achievability of the
Proposed FIP NOx Limit for CGS Unit 1 (September 4, 2012), at 10 (Attachment B); see also
RMB Consulting & Research, Inc., Technical Memorandum Regarding Analysis of the
Achievability of the FIP NOx Limit for San Juan Generating Station and Comparison to Other
Ultra-Low NOx Units (October 21, 2011), at 10 (Attachment C).

14. In addition to failing to provide an adequate compliance margin for Coronado,
EPA established in the Final Rule a new emission calculation procedure to determine compliance
with the NOx emissions limit established by the FIP. Under that new procedure, compliance with
the rolling 30-BOD average NOx emission limit “bubble” is calculated each calendar day, even
if a unit is not in operation on that calendar day.
15. The NOx BART compliance approach set out in the Final Rule was not contemplated in the Proposed Rule. In addition, EPA has acknowledged that the use of an offline unit’s preceding 30-BOD information in determining compliance with a plantwide emission limit is a novel concept in that EPA is unaware of any other permitted emission sources that use this methodology to demonstrate compliance. See EPA, “Questions for AZ Regional Haze FIP Conference Call” (January 22, 2013), at 3 (stating that EPA is “not aware of other permits or emission sources using the same methodology” of using an offline unit’s preceding 30-day totals) (Attachment D). Accordingly, in light of this statement by EPA, and to the best of my information, this compliance methodology has never been included in any proposed air quality regulation and has never been the subject of a proper public notice and comment proceeding.

16. This averaging methodology may very likely create enforcement consequences for SRP, as outlined in the next several paragraphs.

17. NOx emissions in coal-fired boilers are at their lowest level when units return to service after outages where maintenance work has been performed on emission control equipment such as LNB or SCR. This improved performance immediately after an outage is achieved during normal operating conditions and is not material to emission performance experienced during startup, shutdown or equipment malfunctions. During these regularly-scheduled outages, furnace combustion equipment is inspected and repaired or replaced as necessary. SCR equipment also undergoes substantial maintenance with the various components of the ammonia injection system being repaired or replaced and the SCR catalysts being cleaned or replaced. NOx performance begins to degrade soon after the unit is started up, however, and continues to degrade until the next opportunity to perform extended maintenance in a planned outage.
18. Planned outages for Coronado Units 1 and 2 are scheduled to occur every three years to balance unit performance with operating and maintenance costs. This three-year cycle is consistent with standard industry practice. In addition, these planned outages typically last 3.5 to 4 weeks and are scheduled to occur during the off-peak power season to ensure adequate generation resources are available to meet demand, minimize replacement power costs and utilize the skilled labor in the region due to planned unit outages at other generating facilities.

19. As indicated above, because the Final Rule maintains an effective consent decree NOx limit for Unit 2 of 0.080 lb/mmBtu on a 30-BOD average, Coronado likely will not be able to maintain continuous compliance with the new plantwide NOx limit, as demonstrated by the following examples. These examples are not intended to be all-inclusive, or to indicate that SRP believes that 0.050 lb/mmBtu is feasible on a 30-BOD average.

**Example 1:** Coronado Unit 2 is approaching the time for a planned outage to address various routine maintenance activities. Coronado Unit 1 will continue to operate while Unit 2 is in outage. This is a normal situation that will occur at least once every 3 years.

As Coronado Unit 2 approaches its planned outage, portions of the LNB equipment, OFA equipment, and SCR equipment (including catalyst and the ammonia injection grid) will be at or near the point when substantial repair or replacement is required due to routine use. As a result, the Coronado Unit 2 30-BOD NOx average is very likely to be near the 0.080 lb/mmBtu consent decree limit prior to the next scheduled outage for performing emission control system maintenance. Because Coronado must continue to include the last calculated 30-BOD NOx average from Unit 2 in the daily plantwide average calculation during each outage period – even though, during Unit 2’s planned outage, there are zero emissions from Unit 2 – Coronado Unit 1 must operate at a 30-BOD NOx average of approximately 0.050 lb/mmBtu during these periods. EPA has acknowledged this rate is not achievable on a 30-BOD basis.

As a result, Coronado Unit 1 likely would have an insufficient margin in the plantwide 30-BOD NOx limit to allow it to continue operating if
electrical system demand requires low-load cycling or the unit is required to shut down and start up for any maintenance or operational reason during the Unit 2 planned outage. The inability of the limit to accommodate these routine events could result in exceeding the plantwide emissions limit merely because the Final Rule requires the inclusion of the 30-BOD NOx average from Unit 2, which would have zero air emissions during the outage period.

In this event, SRP would have difficulty determining the appropriate course of action, as shutting down Unit 1 would not alleviate an exceedance of the limit. In fact, such an exceedance would continue even if both units are offline and not emitting any NOx because compliance with the plantwide average limit is determined each calendar day with previously calculated unit-level 30-BOD averages. SRP therefore understands that the only way to alleviate the exceedance would be for SRP to perform a startup on Unit 2 and operate until such time that the plantwide 30-BOD NOx average returns to the appropriate range. It could take several days or weeks before Unit 2 could be returned to service, depending upon the scope of the Unit 2 planned outage. Unfortunately, the need to return Unit 2 to service to meet SRP’s customer and system needs could cause an unavoidable exceedance of the FIP’s BART emission limit.

Example 2: Coronado Unit 1 is approaching a planned outage for addressing various routine maintenance activities. Coronado Unit 2 will continue to operate while Unit 1 is in outage. This is a normal situation that will also occur at least once every 3 years.

As Coronado Unit 1 approaches its planned outage, the 30-BOD average for Unit 1 reasonably may be expected to be at or above the effective unit limit of 0.050 lb/mmBtu. Because Coronado must continue to count the 30-BOD NOx average from Unit 1, Coronado likely would need the Unit 2 SCR to achieve a 30-BOD NOx average better than 0.065 lb/mmBtu for the entire duration of the outage to ensure that sufficient margin is available for Unit 1 to return from outage. SRP does not expect that Unit 2 would be capable of achieving what would amount to a short-term permit limit nearly 20 percent lower than the design parameters when this unit is approximately two years into a three-year maintenance cycle.

It is likely that electrical system demand would require low-load cycling on Unit 2 during the Unit 1 outage. SRP specifically schedules routine planned outages during times when overall electrical system energy demands are lower. Low-load cycling could result in exceeding the plantwide emissions limit established in the FIP — despite Unit 2
maintaining compliance with the consent decree limit — only as a result of including the last 30-BOD NOx average from Unit 1.

If an exceedance occurs, shutting down Unit 2 would not immediately alleviate the exceedance due to the requirement for daily calculation of the plantwide average. If startup of Unit 1 was needed to reduce the calculated average, the exceedance would continue until SRP could complete the planned outage maintenance work and operate Unit 1 long enough to reduce the plantwide average. As mentioned in the previous example, such actions could cause an unavoidable exceedance of the FIP’s BART emission limit.

**Example 3:** Coronado Units 1 and 2 are both operating at baseload conditions and the plant is achieving the plantwide NOx limit of 0.065 lb/mmBtu. Unit 2 is operating at or slightly below the consent decree limit of 0.080 lb/mmBtu. Unit 1 is operating at or slightly below 0.050 lb/mmBtu to maintain compliance with the plantwide average. Unit 2 experiences an unplanned outage associated with a unit trip. (Over the past decade, each Coronado unit has experienced multiple trip events per year, in addition to controlled startups and shutdowns.)

In order for SRP to return Unit 2 to service, Unit 1 will be required to operate at a substantially lower emission rate to ensure sufficient margin for Unit 2 to startup without causing an exceedance. This emission rate would need to be less than 0.050 lb/mmBtu on a 30-BOD basis, which EPA has acknowledged repeatedly is not feasible. Thus, SRP may be unable to return Unit 2 to service without exceeding the limit established by the FIP.

20. In the preamble to the Final Rule, EPA indicated that the Agency expects that SRP can meet the 0.065 lb/mmBtu limit on a continuous basis by installing a low load temperature control system on Unit 2 and an SCR system including a low load temperature control system on Unit 1. 77 Fed. Reg. at 72556.

21. SRP contracted with Sargent & Lundy LLC ("S&L") to conduct an SCR feasibility analysis to determine the implications of accepting a lower emission limit for
Coronado Unit 2 as compared with the consent decree limit of 0.080 lb/mmBtu on an individual unit 30-BOD average. S&L estimated the potential impact that unit startups and shutdowns would have on a rolling 30-BOD average NOx emission rate through a modeling exercise. S&L’s modeling analysis demonstrated that SRP would be out of compliance with the Unit 2 consent decree limit of 0.080 lb/mmBtu if that unit experienced more than 1 startup per 30 operating days if a low-load temperature control system was not utilized. Sargent & Lundy LLC, Salt River Project Coronado Generating Station Unit 2 SCR Review: Final Report SL-011433 (August 24, 2012) (Attachment E). SRP is installing a low-load temperature control system for Unit 2 as part of the SCR installation to provide necessary operating flexibility while maintaining compliance with the 0.080 lb/mmBtu consent decree limit. Operational flexibility is critical to SRP in supplying affordable, reliable electricity. This additional work does not enable Coronado to comply with the plantwide NOx emission limit established for Coronado in the Final Rule.

22. SRP retained S&L to perform this analysis because of the company’s extensive experience in providing comprehensive consulting, engineering, design and analysis for electric power generation and power delivery for projects worldwide. In addition, SRP selected S&L based on S&L’s involvement in the various engineering activities associated with the consent decree control improvements at Coronado.

23. EPA also has effectively acknowledged S&L’s expertise. In creating its Base Case v.4.10 using the Integrated Planning Model, EPA retained S&L to develop cost and performance assumptions for sulfur dioxide and NOx emission controls as part of a major update to EPA’s emission control technology assumptions. See United States Environmental Protection Agency, Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, EPA
Base cases, like EPA Base Case v.4.10, provide a projection of electricity sector activity that takes into account federal and state air emission laws and regulations. As demonstrated by its retention by EPA to contribute to this EPA project, the Agency has recognized S&L for its technical expertise related to NOx emission control technology performance and cost.

24. EPA acknowledges that the BART NOx emission limit for Coronado will require SRP to install an SCR system on Unit 1. SRP currently estimates the total cost for this technology to be at least $105 million. To meet the FIP compliance deadline in the Final Rule, SRP will be required to immediately expend significant sums for permitting, analysis of compliance feasibility and options and preliminary planning and design work. Such efforts will require both significant internal staff commitment and the retention of outside experts, at a projected cost of approximately $5,850,000 within the next 12-24 months. To meet the FIP compliance date established in the Final Rule, SRP will need to perform the following work: (1) 2013 – complete upfront engineering and modeling; (2) 2014 – complete the permit application process and begin ordering major equipment to ensure equipment receipt onsite by late 2016; and (3) 2015-2017 – complete construction and tie-in work. If the Final Rule stands, SRP currently expects to incur at least the following estimated annual expenditures to complete installation of SCR on Unit 1 by the deadline established in the Final Rule:

Table 1: Estimated Approximate Annual Cash Flow for Installation of SCR on Coronado Unit 1

<table>
<thead>
<tr>
<th>Calendar Year</th>
<th>Estimated Expenditures (Approximate)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>$850,000</td>
</tr>
<tr>
<td>2014</td>
<td>$5,000,000</td>
</tr>
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<td>2015</td>
<td>$20,000,000</td>
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<tr>
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<td>$55,500,000</td>
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<tr>
<td>2017</td>
<td>$23,650,000</td>
</tr>
</tbody>
</table>

This cash flow will be required to complete installation of SCR on Coronado Unit 1 by the
deadline set forth in the Final Rule.

Date: February 4, 2013

James M. Pratt
Attachment A

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF ARIZONA

UNITED STATES OF AMERICA, Plaintiff,
v. SALT RIVER PROJECT AGRICULTURAL
IMPROVEMENT AND POWER DISTRICT, Defendant.

CIVIL ACTION NO. 2:08-cv-1479-JAT

CONSENT DECREES
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WHEREAS, Plaintiff, the United States of America ("the United States"), on behalf of the United States Environmental Protection Agency ("EPA") is concurrently filing a complaint for injunctive relief and civil penalties pursuant to Sections 113(b)(2) and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413(b)(2) and 7477, alleging that Defendant, Salt River Project Agricultural Improvement and Power District ("SRP") has undertaken construction projects at a major emitting facility in violation of the Prevention of Significant Deterioration ("PSD") provisions of Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-7492, and in violation of the federally approved and enforceable Arizona State Implementation Plan ("SIP");

WHEREAS, in its complaint, the United States alleges, inter alia, that SRP failed to obtain the necessary permits and install the controls necessary under the Act to reduce sulfur dioxide ("SO₂"), oxides of nitrogen ("NOₓ"), and particulate matter ("PM"), and that SRP failed to obtain an operating permit under Title V of the Act that reflects applicable requirements imposed under Part C of Subchapter I of the Act for its Coronado Generating Station ("CGS") located near St. Johns, Arizona;

WHEREAS, the complaint alleges claims upon which relief can be granted against SRP under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477;

WHEREAS, the United States provided SRP and the State of Arizona actual notice of alleged violations in accordance with Section 113(a)(1) and (b) of the Act, 42 U.S.C. § 7413(a)(1) and (b);

WHEREAS, the United States and SRP (collectively, the
“Parties”) have agreed that settlement of this action is in the best interest of the Parties and in the public interest, and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

WHEREAS, the Parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm’s length and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, SRP has cooperated in the resolution of this matter;

WHEREAS, SRP denies the violations alleged in the complaint, and nothing herein shall constitute an admission of liability;

WHEREAS, SRP maintains that its agreement in this Consent Decree to install, correlate, maintain, and operate PM CEMS shall not prevent SRP in any future proceedings from challenging the relationship between the data generated from such PM CEMS, including the averaging period for which such data is reported pursuant to Paragraph 71, and the results of performance tests for PM (e.g., Method 5, 5B, 5I, or 17); and

WHEREAS, the Parties have consented to entry of this Consent Decree without trial of any issues;

NOW, THEREFORE, without any admission of fact or law, it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, and pursuant
to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying complaint, and for no other purpose, SRP waives all objections and defenses that it may have to the Court’s jurisdiction over this action, to the Court’s jurisdiction over SRP, and to venue in this district. SRP consents to and shall not challenge entry of this Consent Decree or this Court’s jurisdiction to enter and enforce this Consent Decree. Except as expressly provided for herein, this Consent Decree shall not create any rights in or obligations of any party other than the Parties to this Consent Decree. Except as provided in Section XXV (Public Comment) of this Consent Decree, the Parties consent to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. Upon entry, the provisions of this Consent Decree shall apply to and be binding upon the Parties, their successors and assigns, and upon SRP’s directors, officers, employees, servants and agents solely in their capacities as such.

3. SRP shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, SRP shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to
enforce this Consent Decree, SRP shall not assert as a defense
the failure of its officers, directors, employees, servants,
agents, or contractors to take actions necessary to comply with
this Consent Decree, unless it is determined to be a Force
Majeure Event as governed by Section XIV of this Consent Decree.

III. DEFINITIONS

4. Every term expressly defined by this Section shall have
the meaning given that term herein. Every other term used in
this Consent Decree that is also a term used under the Act or in
a federal regulation implementing the Act shall mean in this
Consent Decree what such term means under the Act or those
regulations.

5. A “30-Day Rolling Average NO\textsubscript{x} Emission Rate” for a Unit
shall be expressed in lb/mmBtu and calculated in accordance with
the following procedure: first, sum the total pounds of NO\textsubscript{x}
emitted from the Unit during the current Unit Operating Day and
the previous twenty-nine (29) Unit Operating Days; second, sum
the total heat input to the Unit in mmBtu during the current Unit
Operating Day and the previous twenty-nine (29) Unit Operating
Days; and third, divide the total number of pounds of NO\textsubscript{x} emitted
during the thirty (30) Unit Operating Days by the total heat
input during the thirty (30) Unit Operating Days. A new 30-Day
Rolling Average NO\textsubscript{x} Emission Rate shall be calculated for each
new Unit Operating Day. Each 30-Day Rolling Average NO\textsubscript{x} Emission
Rate shall include all emissions that occur during all periods
within any Unit Operating Day, including emissions from startup,
shutdown, and malfunction.

6. A “365-Day Plant-Wide Rolling NO\textsubscript{x} Tonnage Limitation”
means the limitation, as specified in this Consent Decree, on the
total number of tons of NOx emitted from CGS Units 1 and 2 during
a 365-day period beginning on June 1, 2014, and continuing each
day thereafter, and shall include all emissions during startup,
shutdown, and malfunction, unless the malfunction is determined
to be a Force Majeure Event as defined in Section XIV.

7. A “30-Day Rolling Average SO2 Removal Efficiency” means
the percent reduction in the mass of SO2 achieved by a Unit’s FGD
system over a thirty (30) Unit Operating Day period and shall be
calculated as follows: step one, sum the total pounds of SO2
emitted as measured at the outlet of the FGD system for the Unit
during the current Unit Operating Day and the previous
twenty-nine (29) Unit Operating Days as measured at the outlet of
the FGD system for that Unit; step two, sum the total pounds of
SO2 delivered to the inlet of the FGD system for the Unit during
the current Unit Operating Day and the previous twenty-nine (29)
Unit Operating Days as measured at the inlet to the FGD system
for that Unit (this shall be calculated by measuring the ratio of
the lb/mmBtu SO2 inlet to the lb/mmBtu SO2 outlet and multiplying
the outlet pounds of SO2 by that ratio); step three, subtract the
outlet SO2 emissions calculated in step one from the inlet SO2
emissions calculated in step two; step four, divide the remainder
calculated in step three by the inlet SO2 emissions calculated in
step two; and step five, multiply the quotient calculated in step
four by 100 to express as a percentage of removal efficiency. A
new 30-day Rolling Average SO2 Removal Efficiency shall be
calculated for each new Unit Operating Day, and shall include all
emissions that occur during all periods within each Unit
Operating Day, including emissions from startup, shutdown, and
malfunction.

8. A “30-Day Rolling Average SO$_2$ Emission Rate” for a Unit
shall be expressed in lb/mmBtu and calculated in accordance with
the following procedure: first, sum the total pounds of SO$_2$
emitted from the Unit during the current Unit Operating Day and
the previous twenty-nine (29) Unit Operating Days; second, sum
the total heat input to the Unit in mmBtu during the current Unit
Operating Day and the previous twenty-nine (29) Unit Operating
Days; and third, divide the total number of pounds of SO$_2$ emitted
during the thirty (30) Unit Operating Days by the total heat
input during the thirty (30) Unit Operating Days. A new 30-Day
Rolling Average SO$_2$ Emission Rate shall be calculated for each
new Unit Operating Day. Each 30-Day Rolling Average SO$_2$ Emission
Rate shall include all emissions that occur during all periods
within any Unit Operating Day, including emissions from startup,
shutdown, and malfunction.

9. “Affirmative Defense,” as used in this Consent Decree,
means the Affirmative Defense approved by EPA into the Arizona
SIP Rule 18-2-310, “Affirmative Defenses for Excess Emissions Due
to Malfunction, Startup, and Shutdown,” which provides an owner
or operator of a source an Affirmative Defense in a civil or
administrative action, other than a judicial action for
injunctive relief, if the owner or operator of the source has
emissions in excess of an applicable emission limitation due to
malfunction, startup, or shutdown, has complied with the
reporting requirements of Rule 18-2-310.01, and satisfies
additional requirements of Rule 18-2-310.
10. “Arizona DEQ” means the Arizona Department of Environmental Quality.


12. “CEMS” or “Continuous Emission Monitoring System,” means, for obligations involving the monitoring of NOx and SO2 emissions under this Consent Decree, the devices defined in 40 C.F.R. § 72.2, the inlet SO2 lb/mmBtu monitors, and the computer system for recording, calculating, and storing data and equations required by this Consent Decree.

13. “CGS” means SRP’s Coronado Generating Station consisting of two Riley turbo-fired boilers (designated as Unit 1 and Unit 2) and related equipment, which is located near St. Johns, Arizona.


15. “Consent Decree” means this Consent Decree and the Appendix hereto, which is incorporated into the Consent Decree.

16. “Day” means calendar day unless otherwise specified in this Consent Decree.

17. “Electrostatic Precipitator” or “ESP” means a device for removing particulate matter from combustion gases by imparting an electric charge to the particles and then attracting them to a metal plate or screen of opposite charge before the combustion gases are exhausted to the atmosphere.

18. “Emission Rate” for a given pollutant means the number of pounds of that pollutant emitted per million British thermal
units of heat input (lb/mmBtu), measured in accordance with this Consent Decree.


20. “Flue Gas Desulfurization System” or “FGD” means a pollution control device that employs flue gas desulfurization technology, including an absorber utilizing lime, fly ash, or limestone slurry, for the reduction of sulfur dioxide emissions.

21. “Fossil Fuel” means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas.

22. “lb/mmBtu” means one pound of a pollutant per million British thermal units of heat input.

23. “Low NOx Combustion System” means burners and associated combustion air control equipment, including overfire air, for combusting pulverized coal, which control mixing characteristics of the pulverized coal and oxygen, lower the combustion rate, lower oxygen concentration and heat temperature during the initial phase of combustion, and thereby restrain the formation of NOx created by both the nitrogen content of the pulverized coal and by heat.

24. “Netting” shall mean the process of determining whether a particular physical change or change in the method of operation of a major stationary source results in a net emissions increase, as that term is defined at 40 C.F.R. § 52.21(b)(3)(i) and at Section R9-3-101 of the Arizona SIP.

25. “NOx” means oxides of nitrogen, measured in accordance with the provisions of this Consent Decree.

26. “Ownership Interest” means part or all of SRP’s legal
27. “Parties” means the United States of America on behalf of EPA and SRP. “Party” means one of the named “Parties.”

28. “PM” means total filterable particulate matter, measured in accordance with the provisions of this Consent Decree.

29. “PM CEMS” or “PM Continuous Emission Monitoring System” means, for obligations involving the monitoring of PM emissions under this Consent Decree, the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic and/or paper record of PM emissions.

30. “Prevention of Significant Deterioration” or “PSD” means the prevention of significant deterioration of air quality program under Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 - 7492, and 40 C.F.R. § 52.21. It also includes the prevention of significant deterioration of air quality program as approved into the Arizona SIP, Arizona Administrative Code R9-3-101, R9-3-301, R9-3-304, and R9-3-305.

31. “Project Dollars” means SRP’s expenditures and payments incurred or made in carrying out the Environmental Projects identified in Section VIII (Environmental Projects) of this Consent Decree to the extent that such expenditures or payments both: (a) comply with the requirements set forth in Section VIII and Appendix A of this Consent Decree, and (b) constitute SRP’s direct payments for such projects, or SRP’s external costs for contractors, vendors, and equipment.

32. “Removal Efficiency” for a given pollutant means the percentage of that pollutant removed by the applicable emission control equipment.
control device, measured in accordance with the provisions of this Consent Decree.

33. “SCR” means a pollution control device for reducing NOx emissions through the use of selective catalytic reduction technology.

34. “SO₂” means sulfur dioxide, measured in accordance with the provisions of this Consent Decree.

35. “SO₂ Allowance” means “allowance” of SO₂ as defined at 42 U.S.C. § 7651a(3): “an authorization, allocated to an affected Unit by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide.”

36. “State” means the State of Arizona.

37. “Super-Compliant SO₂ Allowance” means an SO₂ Allowance attributable to reductions beyond the requirements of this Consent Decree.


39. “Unit” means CGS Unit 1 or Unit 2.

40. “Unit Operating Day” means, for Unit 1, any calendar day on which Unit 1 fires fossil fuel, and, for Unit 2, any calendar day on which Unit 2 fires fossil fuel.

IV. NOₓ EMISSION REDUCTIONS AND CONTROLS

A. NOₓ Emission Controls

1. Low-NOₓ Combustion System Installation and Performance Requirements

41. SRP shall install a Low NOₓ Combustion System on one Unit no later than June 1, 2009 and on the other Unit by no later
than June 1, 2011. Commencing on the earlier of ninety (90) Unit Operating Days or one hundred eighty (180) calendar days after the Low NO\textsubscript{x} Combustion System installation date and continuing thereafter, each Unit shall achieve and maintain a 30-Day Rolling Average NO\textsubscript{x} Emission Rate of no greater than 0.320 lb/mmBtu.

2. **SCR Installation and Performance Requirements**

42. SRP shall install an SCR on one Unit no later than June 1, 2014. Beginning on June 1, 2014, and continuing thereafter, SRP shall commence continuous operation of the SCR installed on that Unit so as to achieve and maintain a 30-Day Rolling Average NO\textsubscript{x} Emission Rate of no greater than 0.080 lb/mmBtu.

3. **Continuous Operation of NO\textsubscript{x} Controls**

43. SRP shall continuously operate each NO\textsubscript{x} control covered under this Consent Decree at all times that the Unit it serves is in operation, consistent with the technological limitations, manufacturers’ specifications, and good engineering and maintenance practices for minimizing emissions to the extent practicable.

4. **365-Day Plant-Wide Rolling NO\textsubscript{x} Tonnage Limitation**

44. Beginning on June 1, 2014, and continuing thereafter, SRP shall not exceed a 365-Day Plant-Wide Rolling NO\textsubscript{x} Tonnage Limitation at CGS Units 1 and 2 of 7,300 tons.

5. **Monitoring of NO\textsubscript{x} Emissions**

A. **30-Day Rolling Average NO\textsubscript{x} Emission Rate**

45. In determining the 30-Day Rolling Average NO\textsubscript{x} Emission Rate, SRP shall use CEMS in accordance with the procedures of 40 C.F.R. Part 75, except that: (1) NO\textsubscript{x} emissions data need not be bias adjusted, (2) for any CEMS with a span less than 100 parts
per million ("ppm"), the calibration drift and out-of-control
criteria in Procedure 1, section 4.3 of Part 60, Appendix F shall
apply in lieu of the low emitter specifications in Part 75,
Appendix B, section 2.1, (3) for any CEMS with a span less than
or equal to 30 ppm the exemption from the Part 75 linearity check
will not apply and either the Part 75 linearity check or the
cylinder gas audit described in Procedure 1, section 5.1.2 of
Part 60, Appendix F shall be performed on a quarterly basis, and
(4) for the Unit controlled by SCR, an annual relative accuracy
test audit shall meet, at a minimum, a relative accuracy of less
than 20% or an accuracy of less than 0.016 lb/mmBtu (expressed as
the difference between the monitor mean and the reference value
mean).

B. 365-Day Plant-Wide Rolling NO\textsubscript{x} Tonnage Limitation

46. For purposes of calculating the 365-day Plant-Wide
Rolling NO\textsubscript{x} Tonnage Limitation, SRP shall use CEMS in accordance
with the procedures specified in 40 C.F.R. Part 75.

V. SO\textsubscript{2} EMISSION REDUCTIONS AND CONTROLS

A. Best Management Practices for Existing SO\textsubscript{2} Controls

47. Beginning thirty (30) days after entry of this Consent
Decree, SRP shall continuously operate and maintain, to the
maximum extent practicable, its existing FGDs on CGS Unit 1 and
Unit 2 in a manner consistent with good engineering and
maintenance practices for minimizing SO\textsubscript{2} emissions.

B. SO\textsubscript{2} Emission Controls

1. New FGD Installations at First Unit

48. SRP shall install a new FGD on one Unit no later than
thereafter, SRP shall commence continuous operation of the FGD so as to achieve and maintain a 30-Day Rolling Average SO₂ Removal Efficiency at this Unit of at least 95.0% or a 30-Day Rolling Average SO₂ Emissions Rate of no greater than 0.080 lb/mmBtu.

2. **New FGD Installation at Second Unit**

49. SRP shall install a new FGD on the Unit not selected pursuant to Paragraph 48 no later than January 1, 2013. Beginning on January 1, 2013, and continuing thereafter, SRP shall commence continuous operation of the FGD so as to achieve and maintain a 30-Day Rolling Average SO₂ Removal Efficiency at this second Unit of at least 95.0% or a 30-Day Rolling Average SO₂ Emissions Rate of no greater than 0.080 lb/mmBtu.

3. **Continuous Operation of SO₂ Controls**

50. SRP shall continuously operate each FGD covered under this Consent Decree at all times that the Unit it serves is in operation, consistent with the technological limitations, manufacturers’ specifications, and good engineering and maintenance practices for the FGDs for minimizing emissions to the extent practicable.

C. **Surrender of SO₂ Allowances**

51. For purposes of this Subsection, “surrender” means, with regard to SO₂ Allowances, permanently surrendering so that such SO₂ Allowances can never be used to meet any compliance requirement under the Clean Air Act or the Arizona SIP.

52. Except as provided in Paragraph 59, SRP shall not sell, trade, or transfer any SO₂ Allowances allocated to CGS that would otherwise be available for sale, trade, or transfer as a result of the actions taken by SRP to comply with the requirements of
this Consent Decree.

53. Beginning with calendar year 2012, SRP shall surrender to EPA, or transfer to a non-profit third party selected by SRP for purposes of surrender, all SO$_2$ Allowances that have been allocated to CGS in excess of the amount needed to meet its own federal and/or State Clean Air Act regulatory requirements at CGS and Springerville Unit 4, which is located at the Springerville Generating Station.

54. If SRP commences operation of one or more new coal-fired units that it owns in whole or in part, as further described in this Paragraph, in the Western Electricity Coordinating Council Region no earlier than five (5) years and no later than fourteen (14) years from the date this Consent Decree is entered by this Court, then SRP may also use SO$_2$ Allowances, as limited by this Paragraph, allocated to CGS to meet the federal and/or state Clean Air Act regulatory requirements for certain SO$_2$ emissions from such new coal-fired unit(s). SRP may only use such SO$_2$ Allowances pursuant to this Paragraph if such new coal-fired unit(s) is equipped with the Best Available Control Technology (if the new coal-fired unit(s) will be emitting any of the pollutants set forth at 40 C.F.R. § 52.21(b)(50) and the new coal-fired unit(s) will be located in an attainment area for those pollutants) and/or the Lowest Achievable Emission Rate (if the new coal-fired unit(s) will be emitting any of the pollutants set forth at 40 C.F.R. § 51.165(a)(xxxvii) and the new coal-fired unit(s) will be located in a nonattainment area for those pollutants). SRP may only use SO$_2$ Allowances for the SO$_2$ emissions associated with a
total of 400 megawatts (MW) that it owns at such new coal-fired unit(s), whether at one new coal-fired unit (e.g., SRP owns a total of at least 400 MW at one new coal-fired unit) or in the aggregate at multiple new coal-fired units (e.g., SRP owns 100 MW at four new coal-fired units for an aggregate total of 400 MW).

To determine the number of SO₂ Allowances SRP may use pursuant to this Paragraph, SRP may use no more than that number of SO₂ Allowances that cover the same percentage of total SO₂ emissions from such new coal-fired unit(s) as the percentage of SRP’s ownership in such new coal-fired unit(s), on a MW basis. Thus, for example, if SRP owns 400 MW of a new 800 MW coal-fired unit that otherwise meets the requirements of this Paragraph, SRP may use excess SO₂ Allowances allocated to CGS to cover no more than fifty (50) percent of the total SO₂ emissions from such new coal-fired unit. This reduction in the amount of SO₂ Allowances surrendered by or on behalf of SRP would start with the year this new Unit(s) commences operation.

55. SRP shall make its surrender of SO₂ Allowances annually, within forty-five (45) days of its receipt from EPA of the Annual Deduction Reports for SO₂. Any surrender need not include the specific SO₂ Allowances that were allocated to CGS, so long as SRP surrenders SO₂ Allowances that are from the same year and that are equal to the number required to be surrendered under this Subsection.

56. If any SO₂ Allowances are transferred directly to a non-profit third party for surrender to EPA, SRP shall include a description of such transfer in the next report submitted to EPA pursuant to Section XI (Periodic Reporting) of this Consent.
Decree. Such report shall: (i) provide the identity of the non-profit third-party recipient(s) of the SO₂ Allowances and a listing of the serial numbers of the transferred SO₂ Allowances; and (ii) include a certification by the non-profit third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the SO₂ Allowances and will not use any of the SO₂ Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any SO₂ Allowances, SRP shall include a statement that the non-profit third-party recipient(s) surrendered the SO₂ Allowances for permanent surrender to EPA in accordance with the provisions of Paragraph 57 within one (1) year after SRP transferred the SO₂ Allowances to them. SRP shall not have complied with the SO₂ Allowance surrender requirements of this Subsection until all non-profit third-party recipient(s) shall have actually surrendered the transferred SO₂ Allowances to EPA.

57. For all SO₂ Allowances surrendered to EPA, SRP or the non-profit third-party recipient(s) (as the case may be) shall first submit an SO₂ Allowance transfer request form to EPA’s Office of Air and Radiation’s Clean Air Markets Division directing the transfer of such SO₂ Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, SRP or the non-profit third-party recipient(s) shall irrevocably authorize the transfer of these SO₂ Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location
D. Monitoring of SO₂ Emissions

58. In determining the 30-Day Rolling Average SO₂ Emission Rate and the 30-Day Rolling Average SO₂ Removal Efficiency, SRP shall use CEMS in accordance with the procedures of 40 C.F.R. Part 75, except that: (1) SO₂ emissions data need not be bias adjusted; (2) inlet pounds of SO₂ will be calculated as described in Paragraph 7 in lieu of installing an inlet flow monitor, (3) on any CEMS with a span less than 100 ppm, the calibration drift and out-of-control criteria in Procedure 1, section 4.3 of Part 60, Appendix F shall apply in lieu of the low emitter specifications in Part 75, Appendix B, section 2.1, (4) on any CEMS with a span less than or equal to 30 ppm the exemption from the Part 75 linearity check will not apply and either the Part 75 linearity check or the cylinder gas audit described in Procedure 1, section 5.1.2 of Part 60, Appendix F shall be performed on a quarterly basis, and (5) an annual relative accuracy test audit shall meet, at a minimum, a relative accuracy of less than 20% or an accuracy of less than 0.016 lb/mmBtu (expressed as the difference between the monitor mean and the reference value mean).

E. General SO₂ Provisions

59. Provided that SRP is in compliance with all SO₂ emission limitations established in this Consent Decree, nothing in this Consent Decree shall preclude SRP from using, selling, or transferring Super-Compliant SO₂ Allowances that may arise as a result of achieving and maintaining SO₂ emission rates or removal efficiencies at Unit 1 and Unit 2 below the emission limits.
required in this Consent Decree, so long as SRP timely reports
the generation of such Super-Compliant SO₂ Allowances in
accordance with Section XI (Periodic Reporting) of this Consent
Decree.

60. SRP shall not use SO₂ Allowances to comply with any
requirement of this Consent Decree, including by claiming
compliance with any emission limitation required by this Consent
Decree by using, tendering, or otherwise applying SO₂ Allowances
to offset any excess emissions (i.e., emissions above the limits
specified in Paragraphs 48 and 49).

61. Nothing in this Consent Decree shall prevent SRP from
purchasing or otherwise obtaining SO₂ Allowances from another
source for purposes of complying with state or federal Clean Air
Act requirements to the extent otherwise allowed by law.

62. The requirements in Paragraphs 52 through 57 and 59 of
this Consent Decree pertaining to SRP’s surrender of SO₂
Allowances are permanent injunctions not subject to any
termination provision of this Consent Decree.

A. Optimization of Existing ESPs

63. Beginning thirty (30) days after entry of this Consent
Decree, and continuing thereafter, SRP shall operate each ESP on
each Unit at CGS at all times when the Unit is in operation to
maximize PM emission reductions, provided that such operation of
the ESP is consistent with the technological limitations,
manufacturers’ specifications and good engineering and
maintenance practices for the ESP. Except as required during
correlation testing under 40 C.F.R. Part 60, Appendix B,
Performance Specification 11, and Quality Assurance Requirements under Appendix F, Procedure 2, as required by this Consent Decree, SRP shall, at a minimum, to the extent reasonably practicable: (a) fully energize each section of the ESP for each unit, and repair any failed ESP section at the next planned or unplanned Unit outage of sufficient length; (b) operate automatic control systems on each ESP to maximize PM collection efficiency; (c) maintain power levels delivered to the ESPs, consistent with manufacturers’ specifications, the operational design of the Unit, and good engineering practices; (d) inspect for and repair during the next planned or unplanned Unit outage of sufficient length any openings in ESP casings, ductwork and expansion joints to minimize air leakage; and (e) optimize the plate-cleaning and discharge-electrode-cleaning systems for the ESPs at each Unit by varying the cycle time, cycle frequency, rapper-vibrator intensity, and number of strikes per cleaning event.

B. **PM Emission Rate and Monitoring Requirements**

64. Upon installation and commencement of operation of a FGD system for a Unit as required by Paragraphs 48 and 49, and continuing thereafter, that Unit shall achieve and maintain a PM Emission Rate no greater than 0.030 lb/mmBtu.

65. Within one hundred eighty (180) days after each date established by this Consent Decree for SRP to achieve and maintain a PM Emission Rate, and continuing annually thereafter, SRP shall conduct a stack test for PM. To determine compliance with the PM Emission Rate established in Paragraph 64, SRP shall use the reference methods and procedures (filterable portion only) specified in 40 C.F.R. Part 60, App. A-3, Method 5, Method
65B, or Method 5I, App. A-6, Method 17, or alternative stack tests or methods that are requested by SRP and approved by EPA and Arizona DEQ. Each test shall consist of three separate runs performed under representative operating conditions not including periods of startup, shutdown, or malfunction. The sampling time for each run shall be at least 120 minutes and the volume of each run shall be 1.70 dry standard cubic meters (60 dry standard cubic feet). SRP shall calculate the PM Emission Rate from the stack test results in accordance with 40 C.F.R. § 60.8(f). The results of each PM stack test shall be submitted to EPA and Arizona DEQ within forty-five (45) days of completion of each test.

66. When SRP submits the application for amendment to its Title V permit pursuant to Paragraph 134, that application shall include a Compliance Assurance Monitoring (“CAM”) plan, under 40 C.F.R. Part 64, for the PM Emission Rate in Paragraph 64. The PM CEMS required under Paragraph 67 may be used in that CAM plan.

C. PM CEMS

67. SRP shall install, correlate, maintain, and operate PM CEMS on Unit 1 and Unit 2 as specified below. The PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units expressed in lb/mmBtu. The PM CEMS installed at each Unit must be appropriate for the anticipated stack conditions and capable of measuring PM concentrations on an hourly average basis. SRP shall maintain, in an electronic database, the hourly average emission values of all PM CEMS in

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lb/mmBtu. Except for periods of monitor malfunction, maintenance, or repair, SRP shall continuously operate the PM CEMS at all times when the Unit it serves is operating.

68. No later than January 1, 2010, SRP shall submit to EPA and Arizona DEQ for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree a plan for the installation and correlation of the PM CEMS for Unit 1 and Unit 2.

69. No later than one hundred twenty (120) days prior to the deadline to commence operation of the PM CEMS as set forth in Paragraph 71, SRP shall submit to EPA and Arizona DEQ for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed for such PM CEMS.

70. In developing both the plan for installation and correlation of the PM CEMS and the QA/QC protocol, SRP shall use the criteria set forth in 40 C.F.R. Part 60, Appendix B, Performance Specification 11, and Appendix F, Procedure 2. Following EPA’s and Arizona DEQ’s approval of the plan described in Paragraph 68 and the QA/QC protocol described in Paragraph 69, SRP shall thereafter operate the PM CEMS in accordance with the approved plan and QA/QC protocol.

71. Within one hundred eighty (180) calendar days following commencement of operation of each FGD, SRP shall install, correlate, maintain, and operate a PM CEMS on the Unit being controlled by the new FGD, conduct performance specification tests on that PM CEMS, and demonstrate compliance with the PM
CEMS installation and correlation plan submitted to and approved by EPA and Arizona DEQ in accordance with Paragraphs 68 and 69. SRP shall report, pursuant to Section XI (Periodic Reporting), the data recorded by the PM CEMS, expressed in lb/mmBtu on a rolling average 3-hour, 6-hour, 24-hour, 30-day, and 365-day basis in electronic format to EPA and Arizona DEQ and identify in the report any PM concentrations measured by the PM CEMS that are greater than 125% of the highest PM concentration level used in the most recent correlation testing performed pursuant to Performance Specification 11.

72. SRP shall operate the PM CEMS for at least two (2) years. If, after two (2) years of operation, SRP believes that it is infeasible to continue operation of the PM CEMS, SRP may submit a demonstration of infeasibility to EPA. As part of that demonstration, SRP shall submit an alternative PM monitoring plan for review and approval by EPA. If EPA disapproves the alternative monitoring plan, or if EPA rejects SRP’s assertion that it is infeasible to continue operating the PM CEMS, such disagreement is subject to dispute resolution as specified in this Consent Decree.

73. Operation of a PM CEMS shall be considered “infeasible” if, by way of example, the PM CEMS: (a) cannot be kept in proper condition for sufficient periods of time to produce reliable, adequate, or useful data; or (b) SRP demonstrates that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources; or (c) chronic and difficult operational issues at Unit 1 or Unit 2
cannot be resolved through reasonable expenditure of resources;
or (d) the data produced by the CEMS cannot be used to assess PM
emissions from Unit 1 or Unit 2 or performance of that Unit’s
control devices. If EPA determines that SRP has demonstrated
infeasibility pursuant to this Paragraph, SRP shall be entitled
to discontinue operation of and remove the PM CEMS.

D. General PM Provisions

74. Although stack testing shall be used to determine
compliance with the PM Emission Rate established by this Consent
Decree, data from PM CEMS shall be used, at a minimum, to monitor
progress in reducing PM emissions.

75. Nothing in this Consent Decree is intended to, or
shall, alter or waive any applicable law (including but not
limited to any defenses, entitlements, challenges, or
clarifications related to the Credible Evidence Rule, 62 Fed.
Reg. 8314 (Feb. 24, 1997)) concerning the use of data for any
purpose under the Act.

VII. PROHIBITION ON NETTING CREDITS OR OFFSETS

76. Emission reductions at CGS that result from actions to
be taken by SRP after entry of this Consent Decree to comply with
the requirements of this Consent Decree shall not be considered
as a creditable contemporaneous emission decrease for the purpose
of obtaining a netting credit or offset under the Clean Air Act’s
Nonattainment New Source Review and PSD programs.

77. The limitations on the generation and use of netting
credits and offsets set forth in the previous Paragraph do not
apply to emission reductions achieved at CGS that are greater
than those required under this Consent Decree. For purposes of
this Paragraph, emission reductions at CGS are greater than those
required under this Consent Decree if they result from CGS’s
compliance with federally-enforceable emission limits that are
more stringent than those limits imposed on CGS Unit 1 and Unit 2
under this Consent Decree and under applicable provisions of the
Clean Air Act or the Arizona SIP.

78. Nothing in this Consent Decree is intended to preclude
the emission reductions generated under this Consent Decree from
being considered by the State or EPA as creditable
contemporaneous emission decreases for the purpose of attainment
demonstrations submitted pursuant to § 110 of the Act, 42 U.S.C.
§ 7410, or in determining impacts on National Ambient Air Quality
Standards, PSD increment, or air quality related values,
including visibility, in a Class I area.

VIII. ENVIRONMENTAL PROJECTS

79. SRP shall implement the Environmental Projects
(“Projects”) described in Appendix A to this Consent Decree in
compliance with the approved plans and schedules for such
Projects and other terms of this Consent Decree. In implementing
the Projects, SRP shall spend no less than $4,000,000 in Project
Dollars. SRP shall not include its own personnel costs in
overseeing the implementation of the Projects as Project Dollars.

80. SRP shall maintain, and present to EPA upon request,
all documents to substantiate the Project Dollars expended to
implement the Projects described in Appendix A, and shall provide
these documents to EPA within thirty (30) days of a request for
the documents.

81. All plans and reports prepared by SRP pursuant to the
requirements of this Section of the Consent Decree and required
to be submitted to EPA shall be publicly available from SRP
without charge.

82. SRP shall certify, as part of each plan submitted to
EPA for any Project, that SRP is not otherwise required by law to
perform the Project described in the plan, that SRP is unaware of
any other person who is required by law to perform the Project,
and that SRP will not use any Project, or portion thereof, to
satisfy any obligations that it may have under other applicable
requirements of law, including any applicable renewable or energy
efficiency portfolio standards.

83. SRP shall use good faith efforts to secure as much
benefit as possible for the Project Dollars expended, consistent
with the applicable requirements and limits of this Consent
Decree.

84. If SRP elects (where such an election is allowed) to
undertake a Project by contributing funds to another person or
entity that will carry out the Project in lieu of SRP, but not
including SRP’s agents or contractors, that person or
instrumentality must, in writing: (a) identify its legal
authority for accepting such funding; and (b) identify its legal
authority to conduct the Project for which SRP contributes the
funds. Regardless of whether SRP elects (where such election is
allowed) to undertake a Project by itself or to do so by
contributing funds to another person or instrumentality that will
carry out the Project, SRP acknowledges that it will receive
credit for the expenditure of such funds as Project Dollars only
if SRP demonstrates that the funds have been actually spent by
either SRP or by the person or instrumentality receiving them, and that such expenditures met all requirements of this Consent Decree.

85. SRP shall comply with the reporting requirements described in Appendix A.

86. Within sixty (60) calendar days following the completion of each Project required under this Consent Decree (including any applicable periods of demonstration or testing), SRP shall submit to the United States a report that documents the date that the Project was completed, SRP’s results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by SRP in implementing the Project.

**IX. CIVIL PENALTY**

87. Within thirty (30) calendar days after entry of this Consent Decree, SRP shall pay to the United States a civil penalty in the amount of $950,000. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 2008V00564 and DOJ Case Number 90-5-2-1-09174 and the civil action case name and case number of this action. The costs of such EFT shall be SRP’s responsibility. Payment shall be made in accordance with instructions provided to SRP by the Financial Litigation Unit of the U.S. Attorney’s Office for the District of Arizona. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, SRP shall provide notice of payment, referencing the USAO File Number, the DOJ Case Number, and the civil action
case name and case number, to the Department of Justice and to EPA in accordance with Section XVIII (Notices) of this Consent Decree.

88. Failure to timely pay the civil penalty shall subject SRP to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render SRP liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

89. Payments made pursuant to this Section are penalties within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and are not tax-deductible expenditures for purposes of federal law.

X. RESOLUTION OF PAST CIVIL CLAIMS

90. Entry of this Consent Decree shall resolve all civil claims of the United States arising under Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470 to 7492, under the modification provisions of the Clean Air Act's Standards of Performance for New Stationary Sources program, 42 U.S.C. § 7411 and 40 C.F.R. § 60.14, and under Subchapter V of the Clean Air Act, §§ 7661 to 7661f, that arose from modifications that commenced at CGS prior to the date of lodging of this Consent Decree.

XI. PERIODIC REPORTING

91. After entry of this Consent Decree, SRP shall submit to the United States a periodic report, within sixty (60) days after the end of each half of the calendar year (January through June and July through December). The report shall include the
following information:

a. all information necessary to determine compliance with the requirements of the following Paragraphs of this Consent Decree: Paragraphs 41 through 46 concerning NO\textsubscript{x} emissions and monitoring; Paragraphs 47 through 58 concerning SO\textsubscript{2} emissions and monitoring, and the surrender of SO\textsubscript{2} Allowances; and Paragraphs 63 through 66 concerning PM emissions and monitoring;

b. all data recorded by the PM CEMS as required by Paragraph 71, and all periods of monitor malfunction, maintenance, and/or repair as provided in Paragraph 67;

c. all information relating to Super-Compliant SO\textsubscript{2} Allowances that SRP claims to have generated in accordance with Paragraph 59 through compliance beyond the requirements of this Consent Decree;

d. all information relating to the NO\textsubscript{x} Offset Requirement pursuant to Paragraphs 98 and 99; and

e. all information indicating that the installation and commencement of operation for a pollution control device may be delayed, including the nature and cause of the delay, and any steps taken by SRP to mitigate such delay.

92. In any periodic report submitted pursuant to this Section, SRP may incorporate by reference information previously submitted under its Title V permitting requirements, provided that SRP attaches the Title V permit report (or the pertinent portions of such report) and provides a specific reference to the provisions of the Title V permit report that are responsive to
the information required in the periodic report.

93. In addition to the reports required by Paragraph 91, if SRP violates or deviates from any provision of this Consent Decree, SRP shall submit to the United States a report on the violation or deviation within ten (10) business days after SRP knew or should have known of the event. In the report, SRP shall explain the cause or causes of the violation or deviation and any measures taken or to be taken by SRP to cure the reported violation or deviation or to prevent such violation or deviations in the future. If at any time, the provisions of this Consent Decree are included in Title V Permits, consistent with the requirements for such inclusion in this Consent Decree, then the deviation reports required under applicable Title V regulations shall be deemed to satisfy all the requirements of this Paragraph.

94. Each SRP report shall be signed by either SRP’s Manager of Environmental Services or the Plant Manager at CGS, and shall contain the following certification:

This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

95. If any SO₂ Allowances are surrendered to any non-profit third party pursuant to Section V, the non-profit third party’s certification shall be signed by a managing officer of the non-
profit third party and shall contain the following language:

I certify under penalty of law that _____________ [name of non-profit third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I understand that there are significant penalties for making misrepresentations to or misleading the United States.

XII. REVIEW AND APPROVAL OF SUBMITTALS

96. SRP shall submit each plan, report, or other submission required by this Consent Decree to EPA whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. EPA may approve the submittal or decline to approve it and provide written comments explaining the bases for declining such approval as soon as reasonably practicable. Within sixty (60) days of receiving written comments from EPA, SRP shall either: (a) revise the submittal consistent with the written comments and provide the revised submittal to EPA; or (b) submit the matter for dispute resolution, including the period of informal negotiations, under Section XV (Dispute Resolution) of this Consent Decree.

97. Upon receipt of EPA’s final approval of the submittal, or upon completion of the submittal pursuant to dispute resolution, SRP shall implement the approved submittal in accordance with the schedule specified therein or another EPA-approved schedule.

XIII. STIPULATED PENALTIES

98. For any failure by SRP to comply with the terms of this Consent Decree, and subject to the provisions of Sections XIV (Force Majeure) and XV (Dispute Resolution), and except as
provided in Paragraph 99, SRP shall pay, within thirty (30) days after receipt of written demand to SRP by the United States, the following stipulated penalties to the United States:

<table>
<thead>
<tr>
<th>Consent Decree Violation</th>
<th>Stipulated Penalty</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. Failure to pay the civil penalty as specified in Section IX (Civil Penalty) of this Consent Decree</td>
<td>$10,000 per day</td>
</tr>
<tr>
<td>b. Failure to comply with any applicable 30-Day Rolling Average NOₓ Emission Rate, 30-Day Rolling Average SO₂ Emission Rate or 30-Day Rolling Average SO₂ Removal Efficiency</td>
<td>$2,500 per day per violation where the violation is less than 5% in excess of the lb/mmBtu limits, or less than 0.25% below the removal efficiency requirement</td>
</tr>
<tr>
<td></td>
<td>$5,000 per day per violation where the violation is equal to or greater than 5% but less than 10% in excess of the lb/mmBtu limits, or equal to or greater than 0.25% but less than 0.50% below the removal efficiency requirement</td>
</tr>
<tr>
<td></td>
<td>$10,000 per day per violation where the violation is equal to or greater than 10% in excess of the lb/mmBtu limits, or greater than 0.50% below the removal efficiency requirement</td>
</tr>
<tr>
<td>c. Failure to comply with the applicable 365-Day Plant-Wide Rolling NO\textsubscript{x} Tonnage Limitation established by this Consent Decree</td>
<td>$200,000 for the first 365-Day Plant-Wide Rolling NO\textsubscript{x} Tonnage Limitation violation, plus $5,000 for each subsequent 365-Day Plant-Wide Rolling NO\textsubscript{x} Tonnage Limitation violation that includes any day in a previously-assessed 365-Day Plant-Wide Rolling NO\textsubscript{x} Tonnage Limitation violation, plus offset NO\textsubscript{x} emissions in an amount that is at least equal to the number of tons by which the 365-Day Plant-Wide Rolling NO\textsubscript{x} Tonnage Limitation was exceeded, in accordance with the requirements of Paragraph 99, below</td>
</tr>
<tr>
<td>d. Failure to install, commence operation, or continue operation of a NO\textsubscript{x}, SO\textsubscript{2}, or PM control device on either Unit 1 or Unit 2, as required under this Consent Decree</td>
<td>$10,000 per day per violation during the first 30 days, $27,500 per day per violation thereafter</td>
</tr>
<tr>
<td>e. Failure to install or operate CEMS as required in this Consent Decree</td>
<td>$1,000 per day per violation</td>
</tr>
<tr>
<td>f. Failure to apply for any permit required by Section XVI (Permits)</td>
<td>$1,000 per day per violation</td>
</tr>
<tr>
<td>g. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required by this Consent Decree</td>
<td>$750 per day per violation during the first 10 days, $1,000 per day per violation thereafter</td>
</tr>
<tr>
<td>h. Failure to surrender SO\textsubscript{2} Allowances as required by Paragraphs 52 through 55, 57</td>
<td>(a) $27,500 per day plus (b) $1,000 per SO\textsubscript{2} Allowance not surrendered</td>
</tr>
</tbody>
</table>
i. Failure to demonstrate the third-party surrender of an SO\textsubscript{2} Allowance in accordance with Paragraph 56

\hspace{2cm}$2,500 per day per violation

j. Failure to undertake and complete any of the Environmental Projects in compliance with Section VIII (Environmental Projects) of this Consent Decree

\hspace{2cm}$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter

k. Any other violation of this Consent Decree

\hspace{2cm}$1,000 per day per violation

99. NO\textsubscript{x} Offset Requirements.

a. No later than ninety (90) days following written demand by the United States for stipulated penalties pursuant to Paragraph 98.c, SRP shall submit a plan pursuant to Section XII (Review and Approval of Submittals), to obtain actual emission reductions of NO\textsubscript{x} from sources other than CGS in Arizona, Colorado, New Mexico, or Utah to offset excess NO\textsubscript{x} emissions as required by Paragraph 98.c.

b. Such plan shall describe the manner in which SRP will obtain the required NO\textsubscript{x} emission reductions, and shall ensure that the total tons of NO\textsubscript{x} emissions that exceeded the 365-Day Plant-Wide Rolling NO\textsubscript{x} Tonnage Limitation are offset, no later than three (3) years from the date the plan is approved pursuant to Section XII (Review and Approval of Submittals), by an amount of equal or greater actual NO\textsubscript{x} emission reductions from the proposed source(s).

c. SRP shall implement the project(s) in the approved plan in a manner which ensures that the offsetting NO\textsubscript{x} emissions are obtained no later than three (3) years from the date the plan is approved pursuant to Section XII (Review and Approval of Submittals). In the next report submitted to EPA pursuant to
Section XI (Periodic Reporting) following three (3) years from the date the plan is approved, SRP shall provide documentation to demonstrate that it fully and timely obtained the offsetting NO\textsubscript{x} emission reductions in accordance with the approved plan.

d. NO\textsubscript{x} emission reductions required by the Clean Air Act, its implementing regulations, or a state implementation plan shall not be approved as emission reductions to offset NO\textsubscript{x} emissions pursuant to Paragraph 98.c. EPA will apply Clean Air Act § 173(c), 40 C.F.R. § 51.165, and Appendix S to Part 51 for purposes of determining whether to approve the proposed plan.

100. Violations of any limit based on a 30-day rolling average constitutes thirty (30) days of violation but where such a violation (for the same pollutant and from the same Unit) recurs within periods less than thirty (30) days, SRP shall not be obligated to pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

101. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases, whichever is applicable. Nothing in this Consent Decree shall prevent the simultaneous accrual of separate stipulated penalties for separate violations of this Consent Decree.

102. SRP shall pay all stipulated penalties to the United States within thirty (30) days of receipt of written demand to SRP from the United States, and shall continue to make such payments every thirty (30) days thereafter until the violation(s)
no longer continues, unless SRP elects within twenty (20) days of receipt of written demand to SRP from the United States to dispute the accrual of stipulated penalties in accordance with the provisions in Section XV (Dispute Resolution) of this Consent Decree.

103. Stipulated penalties shall continue to accrue as provided in accordance with Paragraph 101 during any dispute, with interest on accrued stipulated penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement, or by a decision of the United States pursuant to Section XV (Dispute Resolution) of this Consent Decree that is not appealed to the Court, accrued stipulated penalties agreed or determined to be owing, together with accrued interest, shall be paid within thirty (30) days of the effective date of the agreement or of the receipt of the United States’s decision;

b. If the dispute is appealed to the Court and the United States prevails in whole or in part, SRP shall, within thirty (30) days of receipt of the Court’s decision or order, pay all accrued stipulated penalties determined by the Court to be owing, together with interest accrued on such penalties determined by the Court to be owing, except as provided in Subparagraph c, below;

c. If the Court’s decision is appealed by either Party, SRP shall, within fifteen (15) days of receipt of the
final appellate court decision, pay all accrued
stipulated penalties determined to be owing, together
with interest accrued on such stipulated penalties
determined to be owing by the appellate court.

Notwithstanding any other provision of this Consent Decree, the
accrued stipulated penalties agreed by the United States and SRP,
or determined by the United States through Dispute Resolution, to
be owing may be less than the stipulated penalty amounts set
forth in Paragraph 98.

104. All stipulated penalties shall be paid in the manner
set forth in Section IX (Civil Penalty) of this Consent Decree.

105. Should SRP fail to pay stipulated penalties in
compliance with the terms of this Consent Decree, the United
States shall be entitled to collect interest on such penalties,

106. The stipulated penalties provided for in this Consent
Decree shall be in addition to any other rights, remedies, or
sanctions available to the United States by reason of SRP’s
failure to comply with any requirement of this Consent Decree or
applicable law, except that for any violation of the Act for
which this Consent Decree provides for payment of a stipulated
penalty, SRP shall be allowed a credit for stipulated penalties
paid against any statutory penalties also imposed for such
violation.

107. If either of the Units exceeds an applicable emission
limitation set forth in this Consent Decree due to malfunction,
SRP has an Affirmative Defense to stipulated penalties under this
Consent Decree, if SRP has complied with the reporting
requirements of Paragraphs 111 and 112 and has demonstrated all of the following:

a. The excess emissions resulted from a sudden and unavoidable breakdown of process equipment or air pollution control equipment beyond the reasonable control of SRP;

b. The air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;

c. If repairs were required, the repairs were made in an expeditious fashion when the applicable emission limitations were being exceeded. Off-shift labor and overtime were utilized where practicable to ensure that the repairs were made as expeditiously as possible. If off-shift labor and overtime were not utilized, SRP satisfactorily demonstrated that the measures were impracticable;

d. The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable during periods of such emissions;

e. All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;

f. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

g. During the period of excess emissions there were no
exceedances of the relevant National Ambient Air Quality Standards that could be attributed to the emission exceedances at CGS;

h. The excess emissions did not stem from any activity or event that could have been foreseen and avoided, or planned, and could not have been avoided by better operations and maintenance practices;

i. All emissions monitoring systems were kept in operation if at all practicable; and

j. SRP’s actions in response to the excess emissions were documented by contemporaneous records.

108. If either of the Units exceeds an applicable emission limitation set forth in this Consent Decree due to startup or shutdown, SRP has an Affirmative Defense to stipulated penalties under this Consent Decree, if SRP has complied with the reporting requirements of Paragraphs 111 and 112 and has demonstrated all of the following:

a. The excess emissions could not have been prevented through careful and prudent planning and design;

b. If the excess emissions were the result of a bypass of control equipment, the bypass was unavoidable to prevent loss of life, personal injury, or severe damage to air pollution control equipment, production equipment, or other property;

c. The air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;
d. The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable during periods of such emissions;

e. All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;

f. During the period of excess emissions there were no exceedances of the relevant National Ambient Air Quality Standards that could be attributed to the emission exceedances at CGS;

g. All emissions monitoring systems were kept in operation if at all practicable; and

h. SRP’s actions in response to the excess emissions were documented by contemporaneous records.

109. If excess emissions occur due to a malfunction during routine startup and shutdown, then those instances shall be treated as other malfunctions subject to Paragraph 107.

110. If excess emissions occur due to a malfunction during scheduled maintenance, then those instances shall be treated as other malfunctions subject to Paragraph 107.

111. For an Affirmative Defense under Paragraphs 107 or 108, SRP shall demonstrate, through submission of the data and information under the reporting provisions of this section, that all reasonable and practicable measures within SRP’s control were implemented to prevent the occurrence of the excess emissions.

112. SRP shall provide notice to the United States in writing of SRP’s intent to assert an Affirmative Defense for malfunction, startup, or shutdown under Paragraphs 107 or 108 as
soon as practicable, but in no event later than twenty-one (21) calendar days following the date of the malfunction, startup or shutdown. This notice shall be submitted to EPA pursuant to the provisions of Section XVIII (Notices). The notice shall contain:

a. The identity of each stack or other emission point where the excess emissions occurred;

b. The magnitude of the excess emissions expressed in the units of the applicable emission limitation and the operating data and calculations used in determining the magnitude of the excess emissions;

c. The time and duration or expected duration of the excess emissions;

d. The identity of the equipment from which the excess emissions emanated;

e. The nature and cause of the emissions;

f. The steps taken, if the excess emissions were the result of a malfunction, to remedy the malfunction and the steps taken or planned to prevent the recurrence of the malfunctions;

g. The steps that were or are being taken to limit the excess emissions; and

h. If the source’s permit contains procedures governing source operation during periods of startup or malfunction and the excess emissions resulted from startup or malfunction, a list of the steps taken to comply with the permit procedures.

113. A malfunction, startup, or shutdown shall not constitute a Force Majeure Event unless the malfunction, startup,
or shutdown also meets the definition of a Force Majeure Event, as provided in Section XIV (Force Majeure).

XIV. FORCE MAJEURE

114. For purposes of this Consent Decree, a “Force Majeure Event” shall mean an event that has been or will be caused by circumstances beyond the control of SRP, its contractors, or any entity controlled by SRP that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite SRP’s best efforts to fulfill the obligation. “Best efforts to fulfill the obligation” include using the best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

115. Notice of Force Majeure Events. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which SRP intends to assert a claim of Force Majeure, SRP shall notify the United States in writing as soon as practicable, but in no event later than twenty-one (21) calendar days following the date SRP first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay or violation. In this notice, SRP shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by SRP to prevent or minimize the delay or violation, the schedule
by which SRP proposes to implement those measures, and SRP’s
t rationale for attributing a delay or violation to a Force Majeure
Event. SRP shall adopt all reasonable measures to avoid or
minimize such delays or violations. SRP shall be deemed to know
of any circumstance which SRP, its contractors, or any entity
controlled by SRP knew or should have known.

116. **Failure to Give Notice.** If SRP fails to comply with
the notice requirements of this Section, the United States may
void SRP’s claim for Force Majeure as to the specific event for
which SRP has failed to comply with such notice requirement.

117. **United States’s Response.** The United States shall
notify SRP in writing regarding SRP’s claim of Force Majeure
within twenty (20) business days of receipt of the notice
provided under Paragraph 115. If the United States agrees that a
delay in performance has been or will be caused by a Force
Majeure Event, the United States and SRP shall stipulate to an
extension of deadline(s) for performance of the affected
compliance requirement(s) by a period equal to the delay actually
caused by the event. In such circumstances, an appropriate
modification shall be made pursuant to Section XXII
(Modification) of this Consent Decree.

118. **Disagreement.** If the United States does not accept
SRP’s claim of Force Majeure, or if the United States and SRP
cannot agree on the length of the delay actually caused by the
Force Majeure Event, the matter shall be resolved in accordance
with Section XV (Dispute Resolution) of this Consent Decree.

119. **Burden of Proof.** In any dispute regarding Force
Majeure, SRP shall bear the burden of proving that any delay in
performance or any other violation of any requirement of this
Consent Decree was caused by or will be caused by a Force Majeure
Event. SRP shall also bear the burden of proving that SRP gave
the notice required by this Section and the burden of proving the
anticipated duration and extent of any delay(s) attributable to a
Force Majeure Event. An extension of one compliance date based
on a particular event may, but will not necessarily, result in an
extension of a subsequent compliance date.

120. **Events Excluded.** Unanticipated or increased costs or
expenses associated with the performance of SRP’s obligations
under this Consent Decree shall not constitute a Force Majeure
Event.

121. **Potential Force Majeure Events.** The Parties agree
that, depending upon the circumstances related to an event and
SRP’s response to such circumstances, the kinds of events listed
below are among those that could qualify as Force Majeure Events
within the meaning of this Section: construction, labor, or
equipment delays; malfunction of a Unit or emission control
device; unanticipated coal supply or pollution control reagent
delivery interruptions; acts of God; acts of war or terrorism;
and orders by a government official, government agency, other
regulatory authority, or a regional transmission organization,
acting under and authorized by applicable law, that directs SRP
to supply electricity in response to a system-wide (state-wide or
regional) emergency. Depending upon the circumstances and SRP’s
response to such circumstances, failure of a permitting authority
to issue a necessary permit in a timely fashion may constitute a
Force Majeure Event where the failure of the permitting authority
to act is beyond the control of SRP and SRP has taken all steps available to it to obtain the necessary permit, including, but not limited to: submitting a complete permit application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority.

122. As part of the resolution of any matter submitted to this Court under Section XV (Dispute Resolution) regarding a claim of Force Majeure, the United States and SRP by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by the Court. SRP shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule (provided that SRP shall not be precluded from making a further claim of Force Majeure with regard to meeting any such extended or modified schedule).

**XV. DISPUTE RESOLUTION**

123. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, provided that the Party invoking such procedure has first made a good faith attempt to resolve the matter with the other Party.

124. The dispute resolution procedure required herein shall be invoked by one Party giving written notice to the other Party.
advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party’s position with regard to such dispute. The Party receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

125. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the Parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between the Parties’ representatives unless they agree in writing to shorten or extend this period.

126. If the Parties are unable to reach agreement during the informal negotiation period, the United States shall provide SRP with a written summary of its position regarding the dispute. The written position provided by the United States shall be considered binding unless, within forty-five (45) calendar days thereafter, SRP seeks judicial resolution of the dispute by filing a petition with this Court. If SRP seeks judicial resolution, the United States’s written summary shall be deemed its initial filing with this Court regarding the dispute. The United States may submit a response to the petition within forty-five (45) calendar days of filing.

127. The time periods set out in this Section may be shortened or lengthened upon motion to the Court of one of the Parties to the dispute, explaining the Party’s basis for seeking
such a scheduling modification.

128. This Court shall not draw any inferences nor establish
any presumptions adverse to either Party as a result of
invocation of this Section or the Parties’ inability to reach
agreement.

129. As part of the resolution of any dispute under this
Section, in appropriate circumstances the Parties may agree, or
this Court may order, an extension or modification of the
schedule for the completion of the activities required under this
Consent Decree to account for the delay that occurred as a result
of dispute resolution. SRP shall be liable for stipulated
penalties for its failure thereafter to complete the work in
accordance with the extended or modified schedule, provided that
SRP shall not be precluded from asserting that a Force Majeure
Event has caused or may cause a delay in complying with the
extended or modified schedule.

130. The Court shall decide all disputes pursuant to
applicable principles of law for resolving such disputes. In
their filings with the Court under Paragraph 126, the Parties
shall state their respective positions as to the applicable
standard of law for resolving the particular dispute.

XVI. PERMITS

131. Unless expressly stated otherwise in this Consent
Decree, in any instance where otherwise applicable law or this
Consent Decree requires SRP to secure a permit to authorize
construction or operation of any device, including all
preconstruction, construction, and operating permits required
under State law, SRP shall make such application in a timely
manner. The United States will use its best efforts to expeditiously fulfill its role in reviewing all permit applications submitted by SRP in order to meet the requirements of this Consent Decree.

132. When permits are required, SRP shall complete and submit applications for such permits to Arizona DEQ to allow sufficient time for all legally required processing and review of the permit request, including requests for additional information by Arizona DEQ. Any failure by SRP to submit a timely permit application for Unit 1 and/or Unit 2 shall bar any use by SRP of Section XIV (Force Majeure) of this Consent Decree, where a Force Majeure claim is based on permitting delays.

133. Notwithstanding the reference to SRP’s Title V permit for CGS in this Consent Decree, the enforcement of that permit shall be in accordance with its own terms and the Act. SRP’s Title V permit for CGS shall not be enforceable under this Consent Decree, although any term or limit established by or under this Consent Decree shall be enforceable under this Consent Decree regardless of whether such term has or will become part of a Title V permit, subject to the terms of Section XXVI (Conditional Termination of Enforcement Under Consent Decree) of this Consent Decree.

134. Within one hundred eighty (180) days after entry of this Consent Decree, SRP shall amend any applicable Title V permit application, or apply for amendments of its Title V permit, to include a schedule for all unit-specific and plant-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree.
including, but not limited to, Emission Rates, Removal Efficiencies, the 365-day Plant-Wide Rolling NOx Tonnage Limitation, and the requirements pertaining to the surrender of SO2 Allowances.

135. Within one (1) year from the commencement of operation of the final pollution control device to be installed on a Unit under this Consent Decree, SRP shall either apply to permanently include the requirements and limitations enumerated in this Consent Decree into a federally enforceable permit or request a site-specific amendment to the Arizona SIP to include the requirements and limitations enumerated in this Consent Decree. The permit or Arizona SIP amendment shall require compliance with the following: (a) any applicable Emission Rate or Removal Efficiency, (b) the 365-day Plant-Wide Rolling NOx Tonnage Limitation, and (c) the SO2 Allowance surrender requirements set forth in this Consent Decree. For purposes of this Consent Decree, the federally enforceable permit must be issued by Arizona DEQ under its authority to issue permits pursuant to the Arizona SIP and not solely under Arizona’s authority to issue permits pursuant to its Title V permit program.

136. SRP shall provide the United States with a copy of each application for a federally enforceable permit or Arizona SIP amendment, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment opportunity.

137. If SRP sells or transfers to an entity unrelated to SRP (“Third Party Purchaser”) part or all of its Ownership Interest covered under this Consent Decree, SRP shall comply with
the requirements of Paragraphs 145 through 148 of this Consent Decree with regard to that Ownership Interest prior to any such sale or transfer unless, following any such sale or transfer, SRP remains the holder of the permit for such facility.

XVII. INFORMATION COLLECTION AND RETENTION

138. Any authorized representative of the United States, including its attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of CGS Unit 1 and Unit 2 at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by SRP or its representatives, contractors, or consultants; and

d. assessing SRP’s compliance with this Consent Decree.

139. SRP shall retain, and instruct its contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in its or its contractors’ or agents’ possession or control, and that directly relate to SRP’s performance of its obligations under this Consent Decree for the following periods: (a) until December 31, 2020 for records concerning physical or operational changes undertaken in accordance with Section IV (NOx Emission Reductions and Controls) and Section V (SO2 Emission Reductions...
and Controls); and (b) until December 31, 2017 for all other records. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

140. All information and documents submitted by SRP pursuant to this Consent Decree shall be subject to any requests under applicable law providing public disclosure of documents unless (a) the information and documents are subject to legal privileges or protection or (b) SRP claims and substantiates in accordance with 40 C.F.R. Part 2 that the information and documents contain confidential business information.

141. Nothing in this Consent Decree shall limit the authority of the EPA to conduct tests and inspections at SRP’s facilities under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal laws, regulations, or permits.

XVIII. NOTICES

142. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States of America:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, DC 20044-7611
DJ# 90-5-2-1-09174

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC  20460

and

Director, Air Division
U.S. EPA Region 9
75 Hawthorne Street [Air-1]
San Francisco, CA 94105

As to SRP:

Manager, Environmental Services
Salt River Project
Environmental, PAB352
1521 N. Project Dr.
Tempe, AZ 85281

and

Corporate Counsel
Salt River Project
Legal Services Department, PAB207
1521 N. Project Dr.
Tempe, AZ 85281

143. All notifications, communications, or submissions made pursuant to this Section shall be sent either by: (a) overnight mail or overnight delivery service with signature required for delivery, or (b) certified or registered mail, return receipt requested. All notifications, communications, and transmissions (a) sent by overnight, certified, or registered mail shall be deemed submitted on the date they are postmarked, or (b) sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service.

144. Either Party may change either the notice recipient or the address for providing notices to it by serving the other Party with a notice setting forth such new notice recipient or address.
XIX. SALES OR TRANSFERS OF OWNERSHIP INTERESTS

145. If SRP proposes to sell or transfer an Ownership Interest to another entity (a “Third Party Purchaser”), SRP shall advise the Third Party Purchaser in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to the United States pursuant to Section XVIII (Notices) of this Consent Decree at least sixty (60) days before such proposed sale or transfer.

146. No sale or transfer of an Ownership Interest shall take place before the Third Party Purchaser and the United States have executed, and the Court has approved, a modification pursuant to Section XXII (Modification) of this Consent Decree making the Third Party Purchaser a party to this Consent Decree and jointly and severally liable with SRP for all the requirements of this Consent Decree that may be applicable to the transferred or purchased Ownership Interests.

147. This Consent Decree shall not be construed to impede the transfer of any Ownership Interests between SRP and any Third Party Purchaser so long as the requirements of this Consent Decree are met. This Consent Decree shall not be construed to prohibit a contractual allocation – as between SRP and any Third Party Purchaser of Ownership Interests – of the burdens of compliance with this Consent Decree, provided that both SRP and such Third Party Purchaser shall remain jointly and severally liable to the United States for the obligations of this Consent Decree applicable to the transferred or purchased Ownership Interests.

148. If the United States agrees, the United States, SRP,
and the Third Party Purchaser that has become a party to this Consent Decree pursuant to Paragraph 146, may execute a modification that relieves SRP of its liability under this Consent Decree for, and makes the Third Party Purchaser liable for, all obligations and liabilities applicable to the purchased or transferred Ownership Interests. Notwithstanding the foregoing, however, SRP may not assign, and may not be released from, any obligation under this Consent Decree that is not specific to the purchased or transferred Ownership Interests, including the obligations set forth in Sections VIII (Environmental Projects) and IX (Civil Penalty). SRP may propose and the United States may agree to restrict the scope of the joint and several liability of any purchaser or transferee for any obligations of this Consent Decree that are not specific to the transferred or purchased Ownership Interests, to the extent such obligations may be adequately separated in an enforceable manner.

**XX. EFFECTIVE DATE**

149. The effective date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court.

**XXI. RETENTION OF JURISDICTION**

150. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, either Party to this Consent Decree may apply to the Court for any relief necessary to construe or
effectuate this Consent Decree.

XXII. MODIFICATION

151. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by the United States and SRP. Where the modification constitutes a material change to any term of this Consent Decree, it shall be effective only upon approval by the Court.

XXIII. GENERAL PROVISIONS

152. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The emission rates and removal efficiencies set forth herein do not relieve SRP from any obligation to comply with other state and federal requirements under the Clean Air Act, including SRP’s obligation to satisfy any State modeling requirements set forth in the Arizona SIP.

153. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

154. In any subsequent administrative or judicial action initiated by the United States for injunctive relief or civil penalties relating to CGS as covered by this Consent Decree, SRP shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the validity of Section X
(Resolution of Past Civil Claims).

155. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve SRP of its obligation to comply with all applicable federal, state, and local laws and regulations. Subject to the provisions in Section X (Resolution of Past Civil Claims), nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the United States to obtain penalties or injunctive relief under the Act or other federal, state, or local statutes, regulations, or permits.

156. Each limit and/or other requirement established by or under this Consent Decree is a separate, independent requirement.

157. Performance standards, emissions limits, and other quantitative standards set by or under this Consent Decree must be met to the number of significant digits in which the standard or limit is expressed. For example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. SRP shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the nearest second significant digit, depending upon whether the limit is expressed to three or two significant digits. For example, if an actual Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. Removal Efficiency for SO₂ is expressed to 3 significant figures - 95.0%. The 95.0% Removal Efficiency requirement is met if, for example, the calculated Removal Efficiency is 94.95%. However,
95.0% Removal Efficiency requirement is not met if, for example, the calculated Removal Efficiency is 94.94%. SRP shall report data to the number of significant digits in which the standard or limit is expressed.

158. This Consent Decree does not limit, enlarge, or affect the rights of either Party to this Consent Decree as against any third parties.

159. This Consent Decree constitutes the final, complete and exclusive agreement and understanding between the Parties with respect to the settlement embodied in this Consent Decree, and supercedes all prior agreements and understandings between the Parties related to the subject matter herein. No document, representation, inducement, agreement, understanding, or promise constitutes any part of this Consent Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

160. Each Party to this action shall bear its own costs and attorneys' fees.

XXIV. SIGNATORIES AND SERVICE

161. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind to this document the Party he or she represents.

162. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

163. Each Party hereby agrees to accept service of process by mail with respect to all matters arising under or relating to
this Consent Decree and to waive the formal service requirements
set forth in Rule 4 of the Federal Rules of Civil Procedure and
any applicable Local Rules of this Court including, but not
limited to, service of a summons.

XXV. PUBLIC COMMENT

164. Both Parties agree and acknowledge that final approval
by the United States and entry of this Consent Decree is subject
to the procedures of 28 C.F.R. § 50.7, which provides for notice
of the lodging of this Consent Decree in the Federal Register, an
opportunity for public comment, and the right of the United
States to withdraw or withhold consent if the comments disclose
facts or considerations which indicate that this Consent Decree
is inappropriate, improper, or inadequate. SRP shall not oppose
entry of this Consent Decree by this Court or challenge any
provision of this Consent Decree unless the United States has
notified SRP, in writing, that the United States no longer
supports entry of this Consent Decree.

XXVI. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER CONSENT DECREE

165. Termination as to completed tasks. As soon as SRP
completes a construction project or any other requirement of this
Consent Decree that is not ongoing or recurring, SRP may, by
motion to this Court, seek termination of the provision or
provisions of this Consent Decree that imposed the requirement.

166. Conditional termination of enforcement through this
Consent Decree. Subject to the provisions of Paragraph 167, after SRP:
a. has successfully completed construction, and has
maintained operation, of all pollution controls as
required by this Consent Decree for a period of two
years; and

b. has obtained all the final permits required by Section
XVI (Permits) of this Consent Decree covering both Unit
1 and Unit 2 that include as federally enforceable
permit terms, all of the Unit performance and other
requirements specified in this Consent Decree;
then SRP may so certify these facts to the United States and this
Court. If the United States does not object in writing with
specific reasons within forty-five (45) days of receipt of SRP’s
certification, then, for any violations of this Consent Decree
that occur after the filing of notice, the United States shall
pursue enforcement of the requirements contained in the Title V
permit through the applicable Title V permit and/or other
enforcement authorities and not through this Consent Decree.

167. Resort to enforcement under this Consent Decree.
Notwithstanding Paragraph 166, if enforcement of a provision in
this Consent Decree cannot be pursued by the United States under
the applicable Title V permit, or if a requirement of this
Consent Decree was intended to be part of a Title V Permit and
did not become or remain part of such permit, then such
requirement may be enforced under the terms of this Consent
Decree at any time.

XXVII. FINAL JUDGMENT

168. Upon approval and entry of this Consent Decree by the
Court, this Consent Decree shall constitute a final judgment
between the United States and SRP.
FOR THE UNITED STATES DEPARTMENT OF JUSTICE

Respectfully submitted,

RONALD J. TENPAS
Assistant Attorney General
Environment and Natural Resources
Division
United States Department of Justice

W. BRNJAMIN FISHEROW
Deputy Chief
Environmental Enforcement Section
Environment and Natural Resources
Division
P.O. Box 7611
Washington, DC 20044-7611
(202) 514-2750
FOR THE UNITED STATES DEPARTMENT OF JUSTICE

DIANE J. HUMETEWA
United States Attorney
District of Arizona

SUE A. KLEIN
Assistant United States Attorney
Two Renaissance Square
40 N. Central Avenue, Suite 1200
Phoenix, AZ 85004-4408
Telephone: (602) 514-7500
FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Respectfully submitted,

[Signature]

GRANTA Y. NAKAYAMA
Assistant Administrator
Office of Enforcement and
Compliance Assurance
United States Environmental
Protection Agency

[Signature]

ADAM M. KUSHNER
Director, Air Enforcement Division
Office of Enforcement and
Compliance Assurance
United States Environmental
Protection Agency

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ILANA S. SALTZBART
Attorney-Advisor
United States Environmental
Protection Agency
1200 Pennsylvania Ave, N.W. (2242A)
Washington, DC 20460
Signature Page for United States of America v. Salt River Project Agricultural Improvement and Power District Consent Decree

FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Respectfully submitted,

WAYNE NASTRI
Regional Administrator, Region 9
United States Environmental Protection Agency

ALLAN ZABEL
Senior Counsel
United States Environmental Protection Agency, Region 9
75 Hawthorne St. (ORC-2)
San Francisco, CA 94105
Signature Page for United States of America v. Salt River Project Agricultural Improvement and Power District Consent Decree

FOR SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT

By: John M. Williams Jr.
President / Vice President
(Printed Name)

Attest and Countersign:

Terrill A. Lonon
Secretary / Assistant Secretary
(Printed Name)

Reviewed by SRP Legal Services Department

Karlee S. Ramaley
(Signed Name)

Date: August 11, 2008

(Printed Name)
Appendix A

Environmental Projects

In compliance with, and in addition to, the requirements in Section VIII of this Consent Decree (Environmental Projects), SRP shall comply with the requirements of this Appendix to ensure that the benefits of the $4 million in Project Dollars are achieved.

I. Overall Environmental Projects Schedule and Budget

A. Within one hundred twenty (120) days from entry of this Consent Decree, as further described below, SRP shall submit plans to EPA for review and approval for spending the $4 million in Project Dollars specified in this Appendix in accordance with the deadlines established in this Appendix. EPA shall determine, prior to approval, that all Projects are consistent with federal law.

B. SRP may, at its election, consolidate the plans required by this Appendix into a single plan.

C. Beginning one hundred twenty (120) days from entry of this Consent Decree, and continuing annually thereafter until completion of each Project (including any applicable periods of demonstration or testing), SRP shall provide EPA with written reports detailing the progress of each Project, including an accounting of Project Dollars spent to date.

D. As required by Paragraph 86 of the Consent Decree, within sixty (60) days following the completion of each Project required under this Consent Decree (including any applicable periods of demonstration or testing), SRP shall submit to the United States a report that documents the date that the Project was completed, SRP’s results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by SRP in implementing the Project.

E. Upon EPA’s approval of the plans required by this Appendix, SRP shall complete the Environmental Projects according to the approved plans. Nothing in the Consent Decree or this Appendix shall be interpreted to prohibit SRP from completing the Environmental Projects before the deadlines specified in the schedule of an approved plan.

II. Clean Diesel School Bus Retrofit Project

A. Within one hundred twenty (120) days from entry of this Consent Decree, SRP shall submit to EPA for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree a plan to retrofit in-service public school bus diesel engines with emission control equipment further described in
this Section, designed to reduce emissions of particulates and/or ozone precursors (the “Clean Diesel School Bus Retrofit Project”) and fund the operation and maintenance of the retrofit equipment for the time-period described below. This Project shall include, where necessary, techniques and infrastructure needed to support such retrofits. SRP shall spend no less than $1.25 million in Project Dollars in performing this Clean Diesel School Bus Retrofit Project. SRP shall complete the installation of the retrofit equipment no later than December 31, 2010, and ensure that the recipients operate and maintain the retrofit equipment from the date of installation through December 31, 2015, by providing funding for operation and maintenance as described in Section II.B.7, below.

B. The plan shall also satisfy the following criteria:

1. Involve public school bus fleets located in the Phoenix metropolitan area (including the City of Phoenix, and the cities and towns in Maricopa County, Pinal County, and Yavapai County).

2. Provide for the retrofit of public school bus diesel engines with EPA or California Air Resources Board (“CARB”) verified emissions control technologies to achieve the greatest measurable mass reductions of particulates and/or ozone precursors for the fleet of school buses in the public school district(s) that participate(s) in this Project. Depending upon the particular EPA or CARB verified emissions control technology selected, the retrofit school bus diesel engines must achieve emission reductions of particulates and/or ozone precursors by 30%-90%, as measured from the pre-retrofit emissions for the particular diesel school bus.

3. Describe the process SRP will use to determine the most appropriate emissions control technology for each particular school bus diesel engine that will achieve the greatest mass reduction of particulates and/or ozone precursors. In making this determination, SRP must take into account the particular operating criteria required for the EPA or CARB verified emissions control technology to achieve the verified emissions reductions.

4. Provide for the retrofit of school bus diesel engines with either: (a) diesel particulate filters or (b) diesel oxidation catalysts and closed crankcase ventilation systems.

5. Describe the process SRP will use to notify public school districts within the geographic area specified in Section II.B.1 that their fleet of school buses may be eligible to participate in the Clean Diesel School Bus Retrofit Project and to solicit their interest in participating in the Project.
6. Describe the process and criteria SRP will use to select the particular public school districts to participate in this Project, consistent with the requirements of this Section.

7. For each of the recipient public school districts, describe the amount of Project Dollars that will cover the costs associated with: (a) purchasing the verified emissions control technology, (b) installation of the verified emissions control technology (including datalogging), (c) training costs associated with repair and maintenance of the verified emissions control technology (including technology cleaning and proper disposal of waste generated from cleaning), and (d) the incremental costs for repair and maintenance of the retrofit equipment from the date of installation through December 31, 2015, including the costs associated with the proper disposal of the waste generated from cleaning the verified emissions control technology. This Project shall not include costs for normal repair or operation of the retrofit school bus.

8. Include a mechanism to ensure that recipients of the retrofit equipment will bind themselves to follow the operating criteria required for the verified emissions control technology to achieve the verified emissions reductions and properly maintain the retrofit equipment installed in connection with the Project for the period beginning on the date the installation is complete through December 31, 2015.

9. Describe the process SRP will use for determining which school buses in a particular public school fleet will be retrofit with the verified emissions control technology, consistent with the criteria specified in Section II.B.2.

10. Ensure that recipient public school district(s), or their funders, do not otherwise have a legal obligation to reduce emissions through the retrofit of school bus diesel engines.

11. For any third party with whom SRP might contract to carry out this Project, establish minimum standards that include prior experience in arranging retrofits, and a record of prior ability to interest and organize fleets, school districts, and community groups to join a clean diesel program.

12. Ensure that the recipient public school district(s) comply with local, state, and federal requirements for the disposal of the waste generated from the verified emissions control technology and follow CARB’s guidance for the proper disposal of such waste.

13. Include a schedule and budget for completing each portion of the Project,
including funding for operation and maintenance of the retrofit equipment through December 31, 2015.

C. In addition to the information required to be included in the report pursuant to Section I.D, above, SRP shall also describe the school districts where it implemented this Project; the particular types of verified emissions control technology (and the number of each type) that it installed pursuant to this Project; the type, year, and horsepower of each retrofit school bus; an estimate of the number of school children effected by this Project, and the basis for this estimate; and an estimate of the emission reductions for each retrofit school bus (using the manufacturer’s estimated reductions for the particular verified emissions control technology), including particulates, hydrocarbons, carbon monoxide, and nitrogen oxides.

D. Upon EPA’s approval of the plan, SRP shall complete the Clean Diesel School Bus Retrofit Project according to the approved plan and schedule.

III. Solar Photovoltaic Project

A. Within one hundred twenty (120) days from entry of this Consent Decree, SRP shall submit to EPA for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree a plan to install conventional fixed flat panel solar photovoltaics and associated equipment (“PV System”) on school buildings in Arizona and to fund the maintenance of such PV Systems for a minimum of 10 years following approval of the plan (“PV Project”). SRP shall spend no less than $2.0 million in Project Dollars in performing this PV Project. SRP shall complete the PV System installations no later than December 31, 2010, and shall maintain the PV Systems for a minimum of ten (10) years following approval of the plan.

B. A PV System shall, at a minimum, consist of: (1) the installation of solar panels at a single location producing at least 10 kilowatts direct current; (2) a grid-tied inverter, appropriately sized for the capacity of the solar panels installed at the location; (3) the appropriate solar panel mounting equipment for the particular school selected, i.e., roof mount or ground mount; (4) wiring, conduit, and associated switchgear and metering required for interconnecting the solar generator to the grid; and (5) appropriate software to enable the school students and staff to monitor the output in kilowatt-hours (both before and after the inverter). SRP shall purchase a ten-year service warrantee for each PV System installed pursuant to the PV Project.

C. The plan shall also satisfy the following criteria:

1. Involve two public school districts in the vicinity of Coronado Generating
Station (e.g., St. Johns, Springerville, Eagar, Show Low) and at least two public school districts in the Phoenix metropolitan area (including the City of Phoenix, and the cities and towns in Maricopa County, Pinal County, and Yavapai County). Specifically, two PV Systems will be installed in the vicinity of Coronado Generating Station and the remainder in the Phoenix metropolitan area.

2. Include a schedule and budget for completing each portion of the PV Project, including installation and maintenance costs for up to ten (10) years following approval of the plan.

3. Describe the process SRP will use to notify public school districts identified in III.C.1, above, that they are eligible to participate in the PV Project and to solicit their interest in participating in the PV Project.

4. Describe the process and criteria SRP will use to select the public school buildings where SRP will install the PV Systems.

5. Identify any person or entity other than SRP that will be involved in the PV Project. SRP shall describe the third party’s role in the Project and the basis for asserting that such entity is able and suited to perform the intended role. For purposes of this Project, third parties shall only include non-profits, state and local agencies, or universities. Any proposed third party must be legally authorized to perform the proposed role and to receive Project Dollars.

D. In addition to the information required to be included in the report pursuant to Section I.D, above, SRP shall also identify the school buildings where the PV Systems were installed, how many total panels, in kilowatts, were installed, the success of the Project in terms of efficiency and kilowatts generated per year, and any lessons learned.

E. Upon EPA’s approval of the plan, SRP shall complete the PV Project according to the approved plan and schedule.

IV. Wood Stove Changeout Project

A. Within one hundred twenty (120) days from entry of this Consent Decree, SRP shall submit to EPA for review and approval pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree a plan to sponsor a wood stove changeout campaign that a state, local, or tribal air pollution control agency (“air pollution control agency) or third-party non-profit will agree to implement in an area that would benefit from reductions of fine particle pollution and/or hazardous air pollutants by replacing pre-1988 wood stoves with EPA-certified wood-stoves
and/or cleaner burning, more energy-efficient hearth appliances (e.g., wood pellet, gas, or propane stoves) (“Wood Stove Changeout Project”). SRP shall spend no less than $750,000 in Project Dollars in performing this Wood Stove Changeout Project, and shall complete the Project no later than December 31, 2011.

B. The Wood Stove Changeout Project that SRP sponsors shall provide information (including, educational efforts and outreach regarding clean-burning alternatives to pre-1988 wood stoves and proper operation of the hearth appliances) and incentives through rebates, discounts, and in some instances, actual replacement of pre-1988 wood stoves for income-qualified residential homeowners, to encourage residential homeowners to replace their old, higher polluting and less energy efficient wood stoves (pre-1988 wood stoves) with cleaner burning, more energy efficient hearth appliances like wood pellet stoves, EPA-certified wood stoves, gas stoves, or propane stoves.

C. SRP shall sponsor the implementation of the Wood Stove Changeout Project in areas in the vicinity of Coronado Generating Station (e.g., St. Johns, Springerville, Eagar, Show Low) that promise significant environmental benefit from the Wood Stove Changeout Project. In determining the specific areas to implement this Project within the aforementioned geographic area, SRP shall give priority to areas with high amounts of air pollution, especially particle pollution and/or hazardous air pollutants, areas located within a geography and topography that makes it susceptible to high levels of particle pollution, or areas that have a significant number of pre-1988 wood-burning appliances.

D. The air pollution control agency(ies) and/or non-profit(s) that SRP selects shall implement the Wood Stove Changeout Project consistent with the materials available on EPA’s website at http://www.epa.gov/woodstoves/index.html.

E. The plan shall also satisfy the following criteria:

1. Identify the air pollution control agency(ies) and/or non-profit(s) selected to implement the Wood Stove Changeout Project.

2. Describe the schedule and budgetary increments in which SRP shall provide the necessary funding to the air pollution control agency(ies) and/or non-profits(s) to implement the Wood Stove Changeout Project.

3. Ensure that the air pollution control agency(ies) and/or non-profit(s) will implement the Wood Stove Changeout Project in accordance with the requirements of this Appendix, and that the Project Dollars will be used to support the actual replacement of pre-1988 wood stoves currently used as the primary or secondary source of residential heat with a cleaner burning, more energy efficient hearth appliance (i.e., wood pellet stove, EPA-
certified wood stove, gas stove, or propane stove). SRP shall limit the use of Project Dollars for administrative costs associated with implementation of the program to no greater than 10% of the Project Dollars SRP provides to a specific air pollution control agency and/or non-profit.

4. Describe all of the elements of the Wood Stove Changeout Project that the air pollution control agency(ies) and/or non-profit(s) will implement, including the type and amount of the incentive that will be made available to residential homeowners through the Wood Stove Changeout Project. If SRP proposes to fund the actual replacement of a pre-1988 wood stove for income-qualified residential homeowners, SRP shall describe the number of energy efficient hearth appliances it intends to make available, the cost per unit, and the criteria the air pollution control agency(ies) and/or non-profit(s) will use to determine which residential homeowners should be eligible for actual stove replacement.

5. If applicable, identify any organizations with which the air pollution control agency(ies) and/or non-profit(s) will partner to implement the Project, including such organizations as: the Hearth, Patio, and Barbecue Association of America, the Chimney Safety Institute of America, a local chapter of the American Lung Association, Tribal organizations, individual stove retailers, propane dealers, facilities that will dispose of old stoves so that they cannot be resold or reused, housing assistance agencies, local fire departments, local health organizations, and local green energy organizations.

6. Describe how the air pollution control agency(ies) and/or non-profit(s) will ensure that the pre-1988 wood stoves will be properly recycled or disposed.

F. Upon EPA’s approval of the plan, SRP shall complete the Wood Stove Changeout Project according to the approved plan and schedule.
Attachment B

RMB Consulting & Research, Inc., Technical Memorandum Regarding Achievability of the Proposed FIP NOx Limit for CGS Unit 1 (September 4, 2012)
TECHNICAL MEMORANDUM

TO: Barbara Sprungl, Salt River Project

FROM: Robert Barton, RMB
      Steve Norfleet, RMB
      Bethany White, RMB

DATE: September 4, 2012

SUBJECT: Achievability of the Proposed FIP NOx Limit for CGS Unit 1

At the request of Salt River Project (SRP), RMB Consulting & Research, Inc. (RMB) has prepared the following memo that discusses the feasibility of demonstrating continuous compliance with the NOx emission limit specified in the recently proposed Federal Implementation Plan (FIP) for Unit 1 at the Coronado Generating Station (CGS). Specifically, RMB addresses the following issues:

• Feasibility of the Proposed FIP NOx Limit Based on Historical Operation
• Review of Other Recently Issued Permits Containing Similar NOx Limits
• Comparison of Compliance Requirements for Other Ultra Low NOx Emitters

Summary

On July 20, 2012, EPA’s response to the proposed regional haze air quality implementation plan submitted by the State of Arizona (e.g., state implementation plan (SIP)) was published in the Federal Register. Arizona’s proposed SIP contained revisions to address the Best Available Retrofit Technology (BART) requirements of the Regional Haze Rule (RHR) for three electric generating plants, including SRP’s Coronado Generating Station (Units 1 and 2), Arizona Public Service’s (APS) Cholla Power Plant (Units 2 – 4), and Arizona Electric Power Cooperative’s (AEPCO) Apache Generating Station (Units 1 – 3). In their response, EPA approved portions of the proposed SIP, including the determination of BART applicability for the above units and the proposed BART determinations and emissions limits for sulfur dioxide (SO2) and particulate matter (PM10). However, EPA disapproved of the BART determinations for NOx for virtually all of the units and issued a proposed FIP with alternative BART determinations and emission limits that were more stringent than those proposed by the Arizona Department of Environmental Quality (ADEQ) in the proposed SIP. EPA’s disapproval was primarily based on alleged deficiencies in the cost and modeling components of ADEQ’s BART determinations.
The BART determination for CGS for NO\textsubscript{x} in the proposed FIP is based on the installation of low-NO\textsubscript{x} burners (LNB) with over-fired air (OFA) and selective catalytic reduction (SCR). The proposed emission limit for Unit 1 is 0.050 lb/mmBtu. EPA issued an alternative limit of 0.080 lb/mmBtu for Unit 2 because of the significant cost associated with altering the SCR design, which has already been completed. However, EPA is requesting comments on an alternative emission limit of 0.050 lb/mmBtu for Unit 2. Both of the proposed NO\textsubscript{x} emission limits are based on a rolling 30-day average using data obtained from the continuous emissions monitoring systems (CEMS) used for Part 75 compliance and are required to include periods of unit startup, shutdown, and malfunction (SSM). These limits are similar to those specified by EPA for the Public Service of New Mexico’s San Juan Generating Station (SJGS) in the recently finalized FIP for the State of New Mexico.\(^1\)

The proposed NO\textsubscript{x} emission limit is the most stringent emission limit imposed on any new or existing pulverized coal unit. While some units equipped with LNB, OFA, and SCR have operated at or below 0.050 lb/mmBtu, these emission levels have not been consistently demonstrated in practice even at steady-state conditions. Furthermore, the lack of an exemption for SSM events renders this limit impossible to meet for most, if not all, units.

RMB performed an analysis to determine whether the units at CGS could meet the proposed FIP NO\textsubscript{x} emission limit based on historical operating data and NO\textsubscript{x} control vendor guarantees. Our findings suggest that the proposed limit does not represent a consistently achievable level of emissions for the units at CGS despite the proposed use of best available NO\textsubscript{x} control technologies. The data show that it is likely that there will be a significant number of exceedances of the limit during normal operation. Unfortunately, these periods may be mischaracterized as non-compliance in the future rather than evidence that the limit itself is unachievable.

We also find that EPA did not adequately assess the long-term achievability of the FIP NO\textsubscript{x} limit with respect to unit startup and shutdown periods. In fact, the data that EPA presented in support of the same limit that was issued for other units in Region 9 actually demonstrates that the limit is not consistently achievable. Finally, our review of the recently issued permits with low-NO\textsubscript{x} emissions limits also does not support the FIP emission limit because none of these units have an equivalent emissions limit to the FIP limit – i.e., one that applies on a 30-day average including startup, shutdown, and malfunction periods. For those units with similar limits, most of them have not yet been constructed, differ significantly in operation and design, and/or have insufficient operating data to fully characterize long-term achievability of the proposed limits. Based on this analysis, our conclusion is that the proposed FIP NO\textsubscript{x} limit of 0.050 lb/MMBtu for the units at CGS is unachievable and inadequately supported.

\(^1\) SJGS was issued a NO\textsubscript{x} emission limit of 0.05 lb/mmBtu (one significant figure) based on a 30-day rolling average. The averaging methodology is based on 30 boiler operating days, which is analogous to the NSPS Subpart D averaging methodology for existing coal-fired units.
Introduction

EPA’s proposed BART NOx limit for Unit 1 is significantly lower than the proposed BART emissions limit in the Arizona Regional Haze State Implementation Plan (0.320 lb/mmBtu) and is even lower than the proposed New Source Performance Standards (NSPS) for new coal-fired electric utility units (~0.07 lb/mmBtu). While RMB is aware of other units with permitted limits of 0.05 lb/mmBtu (see discussion below), this is the most stringent limit that we encountered for any retrofitted unit\(^2\) and has not even been demonstrated achievable at any comparable new unit.

Section 169A(b) of the Clean Air Act (CAA) specifies that any BART emission limits that are established for units at large power plants (> 750 MW) must be determined in accordance with BART Guidelines promulgated by EPA. EPA’s Guidelines for BART Determinations Under the Regional Haze Rule are found in Appendix Y of 40 CFR Part 51. The Guidelines provide a general outline of the procedures that should be used in making BART determinations and include not only steps for determining cost effectiveness but also presumptive limits for utility sources. The presumptive NOx emission limits for coal-fired units are based on boiler types and fuel classification. For dry-bottom turbo-fired boilers the presumptive NOx limits are 0.32 lb/mmBtu for bituminous coal and 0.23 lb/mmBtu for sub-bituminous coal. CGS currently burns 100% subbituminous coal from the Power River Basin (PRB) in Wyoming. Historically these units have burned blends of PRB with bituminous coal and could burn such blends in the future. Therefore, a presumptive NOx limit in the range of 0.23 to 0.32 lb/mmBtu would be consistent with EPA’s Guidelines. The State of Arizona submitted a BART determination for CGS with NOx emission limits of 0.32 lb/mmBtu for both units based on the use of OFA and LNB. This limit is consistent with EPA’s own presumptive BART limits but was rejected in the proposed FIP.

RMB also notes that the proposed emission limit is significantly more stringent than the recently finalized NSPS Subpart Da NOx emission standard for new units. The Subpart Da standard is 0.70 lb/MWh, which corresponds to approximately 0.07 lb/mmBtu on a heat-input basis. BART Guidelines indicate that state regulatory agencies should consider the NSPS in the evaluation except in cases where the NSPS might be outdated. However, since the Subpart Da revisions were finalized in February 2012, it is difficult to see how the new standard could be considered outdated and, thus, excluded from consideration. It is also difficult see how the Subpart Da standard would not represent the most stringent level of available control since it was based on data for units with both combustion controls and SCR.

EPA’s justification of the proposed FIP limit relies solely on previously issued ultra-low NOx limits and vendor guarantees. Unfortunately, this approach does not address the achievability of the limits for CGS since all of the other units considered in EPA’s analysis do not have comparable compliance requirements, have not been constructed and/or do not have sufficient data to assess long-term operation. Likewise, limits based on vendor guarantees do not provide any long-term assurance of compliance since the guarantee only represents a single test under controlled operating conditions.

RMB considers the proposed NOx limit for Unit 1 at CGS to be a clear example of a flawed determination process that does not adequately account for typical unit operating variability. We

\(^2\) Based on 30-day rolling averages including startup, shutdown, and malfunction periods
believe that EPA failed to consider the impact of including SSM in the emission limit, the effects of measurement and process variability, and long-term performance expectations. The following memo discusses the methodology and results of our evaluation for applying a 0.050 lb/mmBtu limit to either unit at CGS.

Methodology

RMB evaluated historical emissions data to determine the overall feasibility of meeting a NO\textsubscript{x} emissions limit of 0.050 lb/mmBtu at either Unit 1 or Unit 2 based on typical unit operation and the anticipated performance of the SCR. This is the best method of assessing the achievability of the limits because it considers the normal operating variability of each unit, particularly with respect to unit startup and shutdown events. RMB notes that the assumption of historical unit operation for this analysis may be conservative. The new control equipment will introduce some uncertainty in the long-term reliability of the units potentially resulting in more frequent unit outages and a greater number of startups and shutdowns and/or extended startup periods.

The data for this evaluation was obtained from the EPA’s Acid Rain Program (ARP) quarterly emissions reports, which includes boiler operating data and emission data on an hourly basis. RMB utilized all available data representing normal unit operation following the installation and tuning of the LNB and OFA systems for each unit. The time period for the evaluation of Unit 1 was July 1, 2009 through August 15, 2012 (~ 37 months) and the time period for Unit 2 was July 1, 2011 through August 15, 2012 (~ 13 months). Consistent with FIP requirements, the data used in the analysis was reported in accordance with ARP reporting procedures. Likewise, the 30-day rolling average was calculated in accordance with the FIP, which is analogous to the procedure used in the recently finalized Subpart Da revisions.

RMB notes that a diluent cap\textsuperscript{3} was used as a substitute value for diluent emissions measurements during startup in accordance with the ARP provisions. This significantly lowered the reported NO\textsubscript{x} emissions during some startup events. Because the diluent cap is an optionally substituted value, RMB does not consider it to be reflective of actual startup emissions and, therefore, we caution against the use of this data in evaluating the technical feasibility in achieving the FIP limit. Without the diluent cap, actual startup emissions and reported 30-day averages will be significantly higher than stated in this evaluation. However, because this assessment is intended to determine the achievability of the limit consistent with other compliance requirements, the application of the diluent cap provides a fair comparison in this analysis.\textsuperscript{4}

As a starting point, RMB determined the date, time and duration of all startup and shutdown events in the evaluation period for each unit. Initiation of unit startup was based on a change in the hourly unit operating time from zero to non-zero. Termination of unit startup was based on an assumption of when the SCR would be placed into service. According to vendor specifications, the catalyst becomes effective at an inlet flue gas temperature of approximately

\textsuperscript{3} EPA added the diluent cap within 40 CFR Part 75 and other rules to reduce the potential for overestimated NO\textsubscript{x} emission rate values that can result from slight errors in diluent measurements at low CO\textsubscript{2} (or high O\textsubscript{2}) concentrations that can occur during SSM events.

\textsuperscript{4} The diluents cap illustrates the difficulty of obtaining representative measurements during SSM periods. Not only is it not possible to operate the SCR during startup due to temperature constraints, but the measurements during such periods are unreliable.
600 degrees F. RMB assumed that this temperature will be reached at approximately 270 MW based on historical plant operating data. RMB assumed that NOx emissions would be continuously controlled to a level of 0.04 lb/mmBtu at an SCR inlet NOx emission level of 0.39 lb/mmBtu based on the vendor guarantee. For inlet levels greater than 0.39 lb/mmBtu, RMB assumed a constant SCR removal efficiency of 90% based on the vendor performance guarantee. RMB also accounted for catalyst deactivation during low-load conditions. Based on historical plant operating data, RMB assumed that the SCR inlet temperature would fall below the minimum reactor temperature at 120 MW during shutdowns and low load conditions.

RMB utilized the hourly emissions data and the above assumptions to develop a software model that would determine unit startup characteristics (number and duration) and provide a calculation of the 30-day rolling average. This information was then used to assess the achievability of the proposed limit for each unit, as summarized below.

**Startup/Shutdown Characteristics**

The duration of unit startups will vary depending on the type of startup (i.e. “cold” or “warm”) and the amount of repairs and maintenance conducted during an outage. A “cold-start” is considered a startup following an extended outage where the unit is offline for more than 96 hours. A “warm-start” is a start-up where the unit is offline for less than 48 hours. Typical startup duration is 26 – 32 hours for a cold-start and 12 – 20 hours for a warm-start. Typical shutdown duration is 3 – 5 hours. 5, 6

RMB analyzed the historical operating data to characterize actual startup and shutdown (SUSD) events that occurred during each evaluation period. Table 1 provides a summary of the number and duration of SUSD events for both units. 7, 8 The duration of SUSD events was similar for both units and consistent with typical operation although Unit 1 had a single, extended startup event in April, 2012 (64 hours). Minimum startup duration was approximately six hours and the average startup duration was approximately 21 hours. There was insufficient data available to further characterize the actual duration of cold-start and warm-start events.

<table>
<thead>
<tr>
<th>Unit</th>
<th>Number of SUSD Events</th>
<th>Duration of SUSD Events [hrs]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total</td>
<td>Avg/Mon</td>
</tr>
<tr>
<td>CGS 1</td>
<td>23</td>
<td>1</td>
</tr>
<tr>
<td>CGS 2</td>
<td>5</td>
<td>1</td>
</tr>
</tbody>
</table>

5 Typical startup/shutdown duration is based on SRP estimates.
6 Termination of startup is based on unit achieving the minimum reactor temperature (600 degrees F).
7 RMB excluded all brief ignition periods (less than one hour of operation) from the evaluation.
8 The average number of SUSD events per month have been rounded up to the nearest whole number.
Table 2 shows the estimated NOx emissions during startup for each unit over the evaluation period.\(^9\) The results show relatively consistent average startup emissions for both units. Maximum emissions are higher for Unit 1 than Unit 2 although Unit 2 results may not be representative due to the limited amount of startup data. The data did not show any correlation between average NOx emission rate and startup duration.

<table>
<thead>
<tr>
<th>Unit</th>
<th>Minimum</th>
<th>Average</th>
<th>Maximum</th>
</tr>
</thead>
<tbody>
<tr>
<td>CGS 1</td>
<td>0.073</td>
<td>0.192</td>
<td>0.280</td>
</tr>
<tr>
<td>CGS 2</td>
<td>0.181</td>
<td>0.209</td>
<td>0.230</td>
</tr>
</tbody>
</table>

For Unit 1, the data showed 23 SUSD events over the evaluation period (~37 months) with an average of one SUSD event per month and a maximum of three events per month occurring in July, 2009 and January, 2011. For Unit 2, the data showed five SUSD events over the evaluation period (~13 months) with an average of one event per month and a maximum of three events per month occurring in July, 2011. RMB also reviewed the historical SUSD activity for the ten-year period 2001 – 2011 to assess the representativeness of the SUSD activity in each evaluation period. Figure 1 shows a cumulative frequency distribution of the startup events for Units 1 and 2. The data show an average of one SUSD event per month and a maximum of five startups for Unit 1 and six startups for Unit 2, which suggests that the maximum number of startups for the current evaluation period is not representative of long-term SUSD activity.

\(^{9}\) Shutdown emissions were not included because a preliminary evaluation showed that these emissions do not significantly contribute to the overall average emissions during a combined SUSD event.
Maximum Potential Emissions

RMB investigated the maximum potential 30-day averages for each unit based on worst-case startup operation. The estimate for Unit 1 is based on a maximum of five startups for the 30-day period based on the unit operating history, including one cold-start event (32 hours) and four warm-starts (20 hours). For Unit 2, the estimate is based on a maximum of six startups, including one cold-start and five warm-starts. The maximum NO\textsubscript{x} emissions rate for each startup is based on the maximum value observed during each respective evaluation period. The analysis assumes normal operating load (90% capacity factor) for the remaining operating hours in the 30-day period.

As shown in Table 3, the maximum potential 30-day averages for Units 1 and 2 are 0.058 lb/mmBtu and 0.059 lb/mmmBtu, respectively. These results suggest that neither can meet the proposed NO\textsubscript{x} emission limit based on worst-case startup operation.

<table>
<thead>
<tr>
<th>Unit</th>
<th>Maximum Potential 30-Day NO\textsubscript{x} Average [lb/mmBtu]</th>
</tr>
</thead>
<tbody>
<tr>
<td>CGS 1</td>
<td>0.058</td>
</tr>
<tr>
<td>CGS 2</td>
<td>0.059</td>
</tr>
</tbody>
</table>

Projected Emissions Based on Typical Operation

RMB analyzed the historical emissions data to determine whether the units could consistently achieve the proposed NO\textsubscript{x} limit based on current operation. A computer model was developed to estimate the 30-day rolling averages based on the assumptions described above. The number of potential deviations over the evaluation period was then estimated based on the number of operating days in which the 30-day average exceeded the proposed NO\textsubscript{x} limit.

As shown in Table 4, the data show the total number of potential exceedances of the proposed FIP NO\textsubscript{x} emission limit over each respective evaluation period for Unit 1 (6) and Unit 2 (27). The annualized average exceedances for Units 1 and 2 are 2 and 21, respectively. The differences in the results can be attributed to longer periods of low-load operation observed for Unit 2 during the evaluation period. The results further demonstrate that both units cannot consistently meet the proposed NO\textsubscript{x} emission limit based on current operation. RMB also notes that the results are based on the assumption of maintaining the guaranteed NO\textsubscript{x} emission rate of 0.04 lb/mmBtu over the life of the catalyst.
Based on our review of the historical operating data, RMB finds that the proposed FIP NO\textsubscript{x} emissions limit does not represent a consistently achievable level of emissions for the units at CGS even with the use of best available NO\textsubscript{x} emission controls. If actually applied, the proposed limits would likely result in periods of non-compliance for these units in the future that reflect an unachievable limit rather than a failure of the plant to adequately operate and maintain the units and control equipment.

**Review of Permits for Other Low NO\textsubscript{x} Emitters**

RMB reviewed the available operating permits and emissions data for those low NO\textsubscript{x} emitters considered by EPA to be “best performing” units\textsuperscript{10} in the supporting documentation for the SJGS BART determination. It is likely that EPA also relied on this information in their justification of the proposed BART determination for CGS.

As shown in Table 5, RMB was able to obtain permit information for seven of the best performing units, although none of them have emissions limits that are comparable to the proposed FIP limit.\textsuperscript{11} In addition, all of these units are subject to the Clean Air Interstate Rule (CAIR) NO\textsubscript{x} annual and ozone season trading programs, which may have been the primary reason for the installation of SCR.

RMB notes that Havana 9 was issued a NO\textsubscript{x} emissions limit of 0.10 lb/mmBtu based on a 30-day rolling average that includes limited\textsuperscript{12} periods of startup, shutdown, and malfunction. The historical operating data for this unit for 2/2008 through 10/2010 presented by EPA in the New Mexico FIP supporting documentation (see Attachment A, Figure A1) shows that the unit is able to consistently maintain 30-day average NO\textsubscript{x} emissions below 0.10 lb/mmBtu. Typical 30-day averages range between 0.03 lb/mmBtu and 0.04 lb/mmBtu although there are a significant number of periods where the 30-day average exceeds 0.050 lb/mmBtu, which suggests that the unit would not be able to consistently demonstrate compliance with the proposed limit.

\textsuperscript{10} Havana Unit 9, Amos Units 1 & 2, Chesterfield Unit 6, Cardinal Units 2 & 3, Colbert Unit 5, Ghent Units 3 & 4 and Mill Creek Unit 3

\textsuperscript{11} RMB excluded the BART NO\textsubscript{x} emission limit for San Juan Generating Station that was issued in the recently finalized FIP for the State of New Mexico. The BART determination in the FIP is currently being litigated, in part, on the basis that the proposed NO\textsubscript{x} limit is unachievable.

\textsuperscript{12} The limit was issued as part of the 2005 consent decree, which allowed the exclusion of startup emissions from the calculation of the 30-day average if those emissions would result in a deviation and the emissions occurred during the fifth and subsequent cold-start of the unit during any 30-day period.

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Table 4 – Estimated Deviations of Proposed FIP NO\textsubscript{x} Limit with SCR

<table>
<thead>
<tr>
<th>Unit</th>
<th>Evaluation Period</th>
<th>Estimated Deviations</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Total</td>
</tr>
<tr>
<td>CGS 1</td>
<td>7/1/2009 - 8/15/2012</td>
<td>6</td>
</tr>
<tr>
<td>CGS 2</td>
<td>7/1/2011 - 8/15/2012</td>
<td>27</td>
</tr>
</tbody>
</table>
RMB reviewed the historical operating data for other “best performing” SCR retrofit installations. Many of these units also exhibited significant periods of 30-day averages in excess of 0.050 lb/mmBtu, which suggest that the FIP limit may not be an achievable limit even for the best performing units. An achievable limit is one that can be met during all periods of normal unit operation (excluding malfunctions). Even a single deviation for a well-controlled and operated source would suggest that the emissions limit is unachievable.

In the supporting documentation of the New Mexico FIP, EPA offered a partial response to the issue by stating that some of the exceedances were outside of the ozone season when the SCR is not operating for some of the units. EPA further suggests that the historical operating data does not necessarily reflect the best performance of the units because many of them are not subject to ultra-low NOx emission limits. RMB notes that, while that may be true for some of the exceedances, many of them indeed occurred within the ozone season (see Attachment A, Figure A2) and, although the sources may not be subject to ultra-low emission limits, the plants have an economic incentive to minimize NOx emissions during that time.

Other Recently Permitted Units

RMB conducted a search of EPA’s RACT/BACT/LAER online database to identify similarly configured units (pulverized coal combustion with LNB and SCR) that were recently permitted with ultra-low NOx limits comparable to the proposed FIP NOx limit. As shown in Table 6, the results included four units with heat-input based emissions limits ranging from 0.05 lb/mmBtu – 0.06 lb/mmBtu. All of the limits were issued for new construction. All of the units were issued secondary emissions limits that were either based on mass emissions rate (lb/hr) or heat input (lb/mmBtu) using a variety of averaging times (24-hour, 30-day roll, 12-month roll). RMB notes that none of the units were issued the same limit and compliance averaging time as proposed in the EPA FIP. Furthermore, with the exception of Wygen III, none of the units are currently operational. Wygen III, a 110 gross megawatt (MWG) unit that came on line in April, 2010, was issued a short-term NOx limit of 65 lb/hr (30-day average) and a long-term limit of 0.05 lb/mmBtu (12-month average). The emission limits issued for Wygen III are not suitable for comparison with the proposed FIP limit because both limits exclude periods of SUSD and either have a higher numeric value or a longer averaging time.

Karn-Weadock Generating Complex

The Karn-Weadock Facility includes a proposed 930 MWG supercritical PC-fired boiler. The unit was recently permitted with an emissions limit of 0.05 lb/mmBtu (30-day rolling average) that excludes SSM and a mass emissions limit of 409.5 lb/hour that includes SSM. The unit has not yet been constructed and it is not clear whether the utility will pursue construction of the unit at this time. Due to significant differences in boiler design and operation and the fact that the boiler has not yet been constructed, we do not consider the proposed limits suitable for comparison with the limits for CGS.

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13 There may be other permitted units not included in the EPA database.
14 Limit is roughly equivalent to 0.06 lb/mmBtu.
Coleto Creek Power Station

Unit 2 at Coleto Creek Power Station is a proposed 650 MW\textsubscript{N} supercritical PC-fired boiler. The unit was recently permitted with NO\textsubscript{x} emissions limits of 0.06 lb/mmBtu (30-day average) and 0.05 lb/mmBtu (12-month average), which exclude periods of startup and shutdown. RMB notes that these units are subject to an alternative work practice standard during startup and shutdown, which requires the plant to burn low-sulfur distillate oil and operate the unit in accordance with “good pollution control practices.” Due to significant differences in boiler design and operation and the fact that the boiler has not yet been constructed, we do not consider the proposed limits suitable for comparison with the limits for CGS.

Tenaska Trailblazer Energy Center

Tenaska Trailblazer Energy Center includes a proposed 750 MW\textsubscript{G} supercritical PC-fired boiler. The unit was recently permitted with multiple heat-input based NO\textsubscript{x} emissions limits of 0.07 lb/mmBtu (24-hour average) and 0.06 lb/mmBtu (30-day rolling average) excluding planned start-up and shutdown periods. The unit is also subject to a NO\textsubscript{x} emission limit of 0.05 lb/mmBtu (12-month average) at all times. The unit was also issued multiple NO\textsubscript{x} mass emissions limits including 498 lb/hour (excluding SSM) and 1,661 lb/hour (including SSM), where both limits are based on a 30-day average. Due to significant differences in boiler design and operation and the fact that the boiler has not yet been constructed, we do not consider the proposed limits suitable for comparison with the limits for CGS.

RMB finds that the recently issued BACT limits do not support the FIP NO\textsubscript{x} limit for the units at CGS. Although there have been several units permitted with similar emissions limits, none of these limits are directly equivalent (same numeric limit and averaging time, including startup and shutdown periods) to the FIP limit. Furthermore, none of the units are suitable for comparison with the units at CGS due to significant differences in boiler design. In addition, all of the above units are based on new construction, which, unlike retrofit units, can be designed to optimize NO\textsubscript{x} reduction in other aspects of combustion (i.e. pulverizer design, boiler height, etc.). Notwithstanding, there is also inadequate data available to confirm the long-term achievability of the limits because the units have not begun operation or only recently became operational. These findings indicate that the proposed FIP NO\textsubscript{x} limit issued for the units at CGS represents the most stringent emission limit suggested for any new or retrofit unit. In addition, the fact that there are no similar units with a long-term operating history at such low emissions levels confirms that EPA failed to adequately consider the achievability of the FIP limit.

Conclusions

Based on our analysis of projected emissions, RMB finds that a NO\textsubscript{x} emission limit of 0.050 lb/mmBtu does not represent a consistently achievable level of emissions for the units at CGS. The data suggests that both units will periodically exceed the proposed limit, which will be inaccurately characterized and reported as excess emissions. RMB also finds that EPA did not adequately consider the impact of SUSD emissions or the ability to measure such emissions during SUSD events in their BART determination. As a result, we conclude that the proposed BART NO\textsubscript{x} emission limit of 0.050 lb/mmBtu should be rejected for both units.
RMB notes that EPA’s goal of minimizing emissions at all operating times, including startup, shutdown and malfunction can be similarly achieved by requiring enforceable operating practices (e.g. work practice standards) that apply during such periods rather than numeric emissions limits. Any numeric limit will impose unreasonable constraints on unit operation that are otherwise unnecessary. This approach has been adopted most recently in finalized revisions to NSPS Subpart Da and the National Emissions Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units, also known as the “Mercury and Air Toxics Rule” (MATS).
<table>
<thead>
<tr>
<th>Plant</th>
<th>Unit ID</th>
<th>NOₓ Trading Program?</th>
<th>Limit</th>
<th>Averaging Period</th>
<th>Applicable During Start-Up/ Shut Down?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Havana</td>
<td>9</td>
<td>CAIR (Annual/Ozone Season)</td>
<td>0.10 lb/mmBtu</td>
<td>30-day rolling</td>
<td>Yes&lt;sup&gt;15&lt;/sup&gt;</td>
</tr>
<tr>
<td>Mill Creek</td>
<td>3</td>
<td>CAIR (Annual/Ozone Season)</td>
<td>0.50 lb/mmBtu</td>
<td>Annual</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>0.52 lb/mmBtu</td>
<td>30-day rolling</td>
<td>No</td>
</tr>
<tr>
<td>Ghent</td>
<td>3</td>
<td>CAIR (Annual/Ozone Season)</td>
<td>0.7 lb/mmBtu</td>
<td>3-hour</td>
<td>No</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td></td>
<td>0.7 lb/mmBtu</td>
<td>3-hour</td>
<td>No</td>
</tr>
<tr>
<td>Chesterfield</td>
<td>6</td>
<td>CAIR (Annual/Ozone Season)</td>
<td>NA</td>
<td></td>
<td>NA</td>
</tr>
<tr>
<td>Amos</td>
<td>1, 2</td>
<td>CAIR (Annual/Ozone Season)</td>
<td>0.46 lb/mmBtu (annual average)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<sup>15</sup> See Footnote Number 5.
### Table 6 – Recently Issued NO₂ BACT Emission Limits

<table>
<thead>
<tr>
<th>Permit Number/Date</th>
<th>Company</th>
<th>Plant</th>
<th>Unit ID</th>
<th>Limit</th>
<th>Averaging Period</th>
<th>Applicable During Start-Up/ Shut Down?</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSDTX1123 12/30/2010</td>
<td>Black Hills Corp.</td>
<td>Wygen</td>
<td>Unit 3</td>
<td>0.05 lb/mmBtu</td>
<td>12-month Rolling</td>
<td>No</td>
<td>Operating since 4/1/2010 Limits are not equivalent to proposed FIP limit.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1.0 lb/MWh</td>
<td>30-day Rolling</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>65.0 lb/hr</td>
<td>30-day Rolling</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>285 TPY</td>
<td></td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>CT-4517 02/05/2007</td>
<td>Tenaska Trailblazer Partners LLC</td>
<td>Tenaska Trailblazer Energy Center</td>
<td>NA</td>
<td>0.05 lb/mmBtu</td>
<td>12-month Rolling</td>
<td>NA</td>
<td>Unit is not constructed Supercritical boiler design is not compatible with CGS units.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.06 lb/mmBtu</td>
<td>30-day Rolling</td>
<td>NA</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.07 lb/mmBtu</td>
<td>24-hour Avg</td>
<td>NA</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>498 lb/hr</td>
<td>30-day Avg</td>
<td>NA</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1661 lb/hr</td>
<td></td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>CT-4631 10/15/2007</td>
<td>Basin Electric Power Cooperative</td>
<td>Dry Fork Station</td>
<td>Unit 1</td>
<td>0.05 lb/mmBtu</td>
<td>12-month Rolling</td>
<td>Yes</td>
<td>Operating since 8/11/2011 Limits are not equivalent to proposed FIP limit.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1.0 lb/MWh</td>
<td>30-day Rolling</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>190.1 lb/hr</td>
<td>30-day rolling</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>832.4 TPY</td>
<td></td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>PSDTX1118 05/03/2010</td>
<td>International Power</td>
<td>Coleto Creek</td>
<td>Unit 2</td>
<td>0.05 lb/mmBtu</td>
<td>12-month Rolling</td>
<td>No</td>
<td>Unit is not constructed Work practice standard applies during unit startup and shutdown Supercritical boiler design is not compatible with CGS units.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.05 lb/mmBtu</td>
<td>12-month Rolling</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.05 lb/mmBtu</td>
<td>12-month Rolling</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>0.05 lb/mmBtu</td>
<td>12-month Rolling</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>341-07 12/29/2009</td>
<td>Consumers Energy</td>
<td>Kamin-Weadock</td>
<td>NA</td>
<td>409.5 lb/hr</td>
<td>24-hour Rolling</td>
<td>Yes</td>
<td>Supercritical boiler design is not compatible with CGS units.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
ATTACHMENT A

Historical Operating Data for Best Performing SCR Retrofit Installations
Figure A1 – Historical 30-Day Rolling Average NOx Emissions for Havana Unit 9 (1/2008 – 11/2010) (Source: EPA)
Figure A2 – Historical 30-Day Rolling Average NOx Emissions for Ghent Unit 4 (1/2008 – 11/2010) (Source: EPA)
Attachment C

RMB Consulting & Research, Inc., Technical Memorandum Regarding Analysis of the Achievability of the FIP NOx Limit for San Juan Generating Station and Comparison to Other Ultra-Low NOx Units (October 21, 2011)
At the request of the Public Service Company of New Mexico (PNM), RMB Consulting & Research, Inc. (RMB) has prepared this memorandum to discuss the feasibility of achieving and demonstrating continuous compliance with the NOₓ emission limit of 0.05 lb/mmBtu specified in the recently issued Federal Implementation Plan (FIP) for the units at San Juan Generating Station (SJGS). Specifically, RMB addresses the following issues:

- Feasibility of the FIP NOₓ Limit Based on Historical Operation
- Review of Permits and Historical Data for Low NOₓ Emitters Cited in the FIP
- Review of Other Recently Permitted Units with Ultra Low NOₓ Limits
- Comparison of Compliance Requirements for Other Ultra Low NOₓ Emitters

Summary

The NOₓ emission limit issued for the units at SJGS appears to be the most stringent NOₓ emissions limit ever imposed on any new or existing pulverized coal unit in the United States. Our review suggests that this limit does not represent a consistently achievable level of emissions for the units at SJGS despite the proposed use of best available NOₓ control technologies and the lowest currently available performance guarantees. Based on our analysis of historical operating data and NOₓ control vendor guarantees, it is likely that there will be a significant number of exceedances of the limit during normal operation. Unfortunately, these periods may be mischaracterized as non-compliance in the future rather than evidence that the limit itself is unachievable.

We also find that EPA did not adequately assess the long-term achievability of the FIP NOₓ limit, particularly with respect to unit startup and shutdown periods. The data that EPA presents in support of the FIP limit actually demonstrates that the limit is not consistently achievable. Finally, our review of the recently issued permits with low-NOₓ emissions limits also does not
support the FIP emission limit because none of these units have an equivalent emissions limit to the FIP limit i.e., one that applies on a 30-day average including startup, shutdown, and malfunction periods. For those units with similar limits, most of them have not yet been constructed, differ significantly in operation and design, and/or have insufficient operating data to fully characterize long-term achievability of the proposed limits. Based on this analysis, our conclusion is that the FIP NO\textsubscript{x} limit for the units at SJGS is unachievable and inadequately supported.

Feasibility of FIP NO\textsubscript{x} Limit

In the recently issued FIP for SJGS, EPA included a NO\textsubscript{x} emission limit for all four units of 0.05 lb/mmBtu based on a 30-boiler operating day rolling average, which applies at all times, including periods of unit startup, shutdown, and malfunction (SSM). The FIP limit is significantly lower than the presumptive NO\textsubscript{x} limits provided by EPA’s BART Guidelines, lower than the New Mexico Regional Haze State Implementation Plan submitted to EPA on July 5, 2011 and is even lower than the proposed New Source Performance Standards (NSPS) for new coal-fired electric utility units (~0.07 lb/mmBtu). While we are aware of other units with permitted limits of 0.05 lb/mmBtu (see discussion below), this is the most stringent limit that we encountered for any new or retrofit unit\(^1\).

Section 169A(b) of the CAA specifies that any Best Available Retrofit Technology (BART) emission limits that are established for units at large power plants (> 750 MW) must be determined in accordance with BART Guidelines promulgated by EPA. EPA’s Guidelines for BART Determinations Under the Regional Haze Rule are found in Appendix Y of 40 CFR Part 51. The Guidelines provide a general outline of the procedures that should be used in making BART determinations and include not only steps for determining cost effectiveness but also presumptive limits for utility sources.

EPA’s BART Guidelines establish “presumptive NO\textsubscript{x} emission limits for BART-Eligible coal-fired units” based on boiler types and fuel classification. For dry-bottom wall-fired boilers the presumptive NO\textsubscript{x} limits are 0.39 lb/mmBtu for bituminous coal and 0.23 lb/mmBtu for sub-bituminous coal. SJGS has dry-bottom wall-fired boilers and burns a New Mexico coal that has a blend of bituminous and sub-bituminous qualities. Based on its fuel characteristics, a conservative presumptive NO\textsubscript{x} limit in the range of 0.23 to 0.27 lb/mmBtu would be consistent with EPA’s Guidelines.

Instead of pursuing the approach represented by the presumptive NO\textsubscript{x} limits in EPA’s own guidelines, EPA’s justification for the FIP limit relies solely on previously issued ultra-low NO\textsubscript{x} limits and vendor guarantees. Unfortunately, this approach does not address the achievability of the limits for San Juan since most of the other units considered in EPA’s analysis have not been constructed or may not have sufficient data to assess long-term operation. Likewise, limits based on vendor guarantees do not provide any long-term assurance of compliance since the vendor obligation typically ends when the performance guarantee is met via a short term test.

\[1\] Based on 30-day rolling averages including startup, shutdown, and malfunction periods.
The Regional Haze Rule also stipulates that it is the States that have the primary responsibility for determining BART for the affected facilities within the state. New Mexico submitted its BART determination of 0.23 lb/mmBtu based on Selective Non-Catalytic Reduction technology to EPA in the July 5, 2011 SIP. This limit is consistent with the EPA-established presumptive BART, but was rejected by EPA in the FIP.

It is particularly interesting that the FIP NOₓ standard is significantly more stringent than the recently proposed NSPS Subpart Da NOₓ limit for new units of 0.70 lb/MWh, which corresponds to a limit of about 0.07 lb/mmBtu. EPA’s Guidelines indicate that state regulatory agencies should consider NSPS limits in the BART evaluation except in cases where the NSPS might be considered outdated (e.g. “technology determinations from the 1970s or early 1980s”). Since the Subpart Da revisions were proposed early in 2011, it is difficult to see how they could be considered outdated. It would also be difficult to argue how the Subpart Da limits would not represent the most stringent level of available control since the limits were based on data for units with both combustion controls and SCR. Instead, the inconsistency between the proposed new Subpart Da limit and the FIP limit seems to be entirely related to EPA’s failure to consider achievability in setting the FIP emission limit, including EPA’s failure to consider the impact of including SSM in the emission limit, the effect of measurement and process variability, and long-term performance expectations.

We believe that the FIP NOₓ limits for the units at SJGS are a clear example of an unachievable emissions limit that does not adequately account for typical unit operating variability. This memorandum discusses the methodology and results of our evaluation of feasibility of the NOₓ limits for the units at SJGS based on historical operating data.

**Methodology**

RMB evaluated the historical emissions data to determine the overall feasibility of meeting the FIP NOₓ emissions limit based on typical unit operation. We believe that this is the most appropriate method of assessing the achievability of the limits because it considers the normal operating variability of each unit, particularly with respect to unit startup and shutdown events. RMB notes that the assumption of historical unit operation for this analysis may be conservative. The new control equipment will introduce some uncertainty in the long-term reliability of the units, potentially resulting in more frequent unit outages and a greater number of startups and shutdowns and/or extended startup periods.

The data for this evaluation was obtained from the Acid Rain Program (ARP) quarterly emissions reports for Units 1  4. The time period under evaluation for Units 1, 3, and 4 was January 1, 2009 through June 30, 2011 and for Unit 2 was May 1, 2009 through June 30, 2011. The start dates for this evaluation are considered representative because they correspond with the completion of the low NOₓ burner installation on each unit. Consistent with FIP requirements, the data used in the analysis was reported in accordance with the reporting procedures of the ARP. Likewise, the 30-day rolling average was calculated using the daily average methodology required under the FIP, i.e., a daily NOₓ rate emission average is determined for each boiler operating day (any day fuel is fired in the boiler), and the daily NOₓ emission rate is then averaged with the previous 29 boiler operating days to determine compliance with the NOₓ limit.
RMB notes that the use of the diluent cap was applied when applicable, consistent with the Part 75 monitoring provisions, which significantly affected the reported NOx emissions during startup events. Because the diluent cap represents an optionally substituted value, we do not consider it to be reflective of actual startup emissions and, therefore, we caution against the use of this data in evaluating the technical feasibility in achieving the FIP limit. Without the diluent cap, actual startup emissions and reported 30-day averages will be significantly higher than stated in this evaluation. However, because this assessment is intended to determine the achievability of the limit consistent with other compliance requirements, the application of the diluent cap provides a fair comparison in this analysis.

As a starting point, RMB determined the date/time and duration of all startup events in the evaluation period. Initiation of unit startup was based on a change in the hourly unit operating time from zero to non-zero. Termination of unit startup was based on an assumption of when the SCR would be placed into service. According to vendor specifications, the SCR operation becomes effective at an inlet flue gas temperature of 580 degrees F. RMB assumed that this temperature will be reached at approximately 40% of the maximum rated load of the unit. Therefore, RMB assumed termination of startup based on the unit achieving 40% of the maximum rated load.

Upon achieving SCR operation, RMB assumed that NOx emissions would be continuously controlled to a level of 0.03 lb/mmBtu at a SCR inlet NOx emission level of 0.30 lb/mmBtu. This represents the lowest available emissions rate performance guarantee that is currently available from NOx control vendors. For inlet levels greater than 0.30 lb/mmBtu, RMB assumed a constant SCR removal efficiency of 90% based on the vendor performance guarantee. RMB notes that we have significant concern over the ability of the SCR to maintain such low levels on a long-term basis, especially considering the design ammonia slip limit of 2 ppm required by the FIP.

RMB utilized the hourly emissions data and the above assumptions to develop a software model that would determine unit startup characteristics (number and duration) and provide a calculation of the 30-day rolling average. This information was then used to assess the achievability of the FIP limit for each unit, as summarized below.

---

2 The diluents cap provisions allow the operators of coal-fired boiler to calculate NOx lb/mmBtu emissions using a minimum 5% CO2 value. EPA added the diluent cap within 40 CFR Part 75 and other rules to reduce the potential for overestimated NOx emission rate values that can result from slight errors in diluent measurements at low CO2 (or high O2) concentrations that can occur during SSM events.

3 The diluent cap illustrates the difficulty of obtaining representative measurements during SSM periods. Not only, as discussed later, is it not possible to operate the SCR during startup due to temperature constraints, but the measurements during such periods are unreliable.
Unit Startup Characteristics

Table 1 provides a summary of the number and duration of startup events for all units over the evaluation period. RMB excluded all brief ignition periods (less than one hour of operation) from the evaluation. The duration of unit startups events was similar for all units. Minimum startup duration was approximately 2-4 hours and the average startup duration was 14-16 hours. Due to limitations in the methodology and available data, RMB was unable to accurately quantify the maximum duration of startup events. The estimated maximum startup duration for all units is 19 hours based on feedback from plant personnel. The duration of startup is dependent on the amount of repairs and maintenance conducted during an outage. Startup duration could be greater than 19 hours especially after maintenance outages of three weeks or longer. For a turbine repair, startup duration could be 72 hours or greater.

Table 1 - Number/Duration of Startups (1/2009-6/2011 or, for Unit 2, 5/2009-6/2011)

<table>
<thead>
<tr>
<th>Unit</th>
<th>Number of Startups</th>
<th>Duration of Startups (hours)</th>
<th>Avg/Month</th>
<th>Max/Month</th>
<th>Min</th>
<th>Max</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>46</td>
<td>1-2</td>
<td>2-3</td>
<td>3</td>
<td>33</td>
<td>15</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>59</td>
<td>1-2</td>
<td>2-3</td>
<td>2</td>
<td>68</td>
<td>14</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>39</td>
<td>1-2</td>
<td>1-2</td>
<td>4</td>
<td>47</td>
<td>16</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>28</td>
<td>0-1</td>
<td>1-2</td>
<td>3</td>
<td>52</td>
<td>15</td>
<td></td>
</tr>
</tbody>
</table>

Table 2 provides the average, maximum and minimum startup NOx emissions for each unit over the evaluation period, assuming operation of the SCR. RMB notes that these values are significantly affected by the application of the diluent cap. For example, average startup emissions for Unit 1 without the application of the diluent cap are approximately 0.80 lb/mmBtu.

Table 2 – Estimated Startup NOx Emissions (1/2009-6/2011 or, for Unit 2, 5/2009-6/2011)

<table>
<thead>
<tr>
<th>Unit</th>
<th>NOx Emissions [lb/mmBtu]</th>
<th>Min</th>
<th>Max</th>
<th>Average</th>
<th>Average (weighted)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>0.033</td>
<td>0.409</td>
<td>0.192</td>
<td>0.219</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>0.027</td>
<td>0.325</td>
<td>0.143</td>
<td>0.130</td>
<td></td>
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<tr>
<td>3</td>
<td>0.049</td>
<td>0.235</td>
<td>0.143</td>
<td>0.136</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>0.048</td>
<td>0.204</td>
<td>0.131</td>
<td>0.125</td>
<td></td>
</tr>
</tbody>
</table>

4 Excessive startup durations (e.g. >24 hours) reflect startup events where the unit did not achieve 40% of the maximum rated load. Actual startup duration cannot be determined in these circumstances based on the available data.

5 Average emissions are weighted according to startup duration for each event.
Maximum Potential Reporting Average

RMB investigated the maximum potential 30-day average based on worst-case startup operation for each of the units. RMB assumed a maximum of three startups for the 30-day period and the maximum observed NOx emissions for each startup based on the historical data. The analysis assumes each startup is completed within 24 hours with no steady-state SCR operation (e.g., aborted startup).

The maximum potential 30-day NOx averages for Units 1–4 are shown in Table 3. The results demonstrate that Units 1 and 2 cannot meet the FIP NOx emission limit based on the worst-case operation and Units 3 and 4 can only marginally meet the emissions limit.

Table 3 - Maximum Potential 30-Day NOx Average

<table>
<thead>
<tr>
<th>Unit</th>
<th>Maximum Potential 30-Day NOx Average [lb/mmBtu]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.068</td>
</tr>
<tr>
<td>2</td>
<td>0.060</td>
</tr>
<tr>
<td>3</td>
<td>0.051</td>
</tr>
<tr>
<td>4</td>
<td>0.047</td>
</tr>
</tbody>
</table>

Analysis of Historical Data

RMB analyzed the historical emissions data to determine whether the units could consistently achieve the FIP NOx limit based on current operation. A computer model was developed to estimate the 30-day rolling averages based on the assumptions described above. The number of potential deviations over the evaluation period was then estimated based on the number of operating days in which the 30-day average exceeded the FIP NOx limit.

As shown in Table 4, the data indicate a significant number of potential exceedances over the evaluation period for Unit 1 (91), Unit 2 (32), and Unit 3 (15) and no exceedances for Unit 4. The results clearly demonstrate that Units 1–3 cannot consistently meet the FIP NOx emission limit based on current operation. Although the results for Unit 4 do not show any deviations over the evaluation period, RMB notes that this may reflect an unusual pattern of operation. As noted above, emissions under worst-case operating conditions for Unit 4 show that compliance with the limit would be marginal. Further, RMB notes that these results are based on the conservative assumption of maintaining the guarantee NOx emission rate of 0.03 lb/mmBtu over the life of the catalyst, which is unlikely at a 2 ppm ammonia slip limit.
Table 4 – Estimated Deviations of FIP NOx Limit with SCR (1/2009 – 6/2011 or, for Unit 2, 5/2009-6/2011)

<table>
<thead>
<tr>
<th>Unit</th>
<th>FIP Deviations</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>91</td>
</tr>
<tr>
<td>2</td>
<td>32</td>
</tr>
<tr>
<td>3</td>
<td>15</td>
</tr>
<tr>
<td>4</td>
<td>0</td>
</tr>
</tbody>
</table>

Summary of Findings

Based on our review of the historical operating data, we find that the FIP NOx emissions limit does not represent a consistently achievable level of emissions for the units at SJGS even with the use of best available NOx emission controls and the lowest available emission rate performance guarantee. Unfortunately, this will likely result in periods of non-compliance for these units in the future that reflect an unachievable limit rather than a failure of the plant to adequately operate and maintain the units and control equipment. RMB notes that EPA’s goal of minimizing emissions at all operating times, including startup, shutdown and malfunction, can be achieved by requiring enforceable operating practices (e.g. work practice standards) that apply during such periods rather than numeric emissions limits. Any numeric limit will impose unreasonable constraints on unit operation that are otherwise unnecessary.

Review of Permits for Low NOx Emitters Cited in the FIP

RMB reviewed the operating permits for some of the units that were cited by EPA in the FIP as the “best performing” SCR retrofit installations. The purpose of this investigation was to identify whether any of these units have been issued NOx emissions limits that include startup and shutdown periods similar to those for the units at SJGS. As shown in Table 5, RMB was able to obtain permit information for several of these units, although none of them have emissions limits that are reasonably comparable to the San Juan FIP limit. It is probable that many of these units do not have ultra-low NOx limits. Rather, the installation of low-NOx control technologies may have been motivated by emissions reduction under a NOx allowance trading program.

RMB notes that Havana 9 was issued a NOx emissions limit of 0.10 lb/mmBtu based on a 30-day rolling average that includes limited6 periods of startup, shutdown, and malfunction. The historical operating data for this unit for 2/2008 through 10/2010 presented by EPA in the FIP supporting documentation (see attachment A1) shows that the unit is able to consistently maintain 30-day average NOx emissions below 0.10 lb/mmBtu. Typical 30-day averages range between 0.03 lb/mmBtu and 0.04 lb/mmBtu although there are a significant number of periods where the 30-day average exceeds 0.05 lb/mmBtu, which suggests that the unit would not be able to consistently demonstrate compliance with a FIP-equivalent limit.

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6 The limit was issued as part of a 2005 consent decree, which allowed the exclusion of startup emissions from the calculation of the 30-day average if those emissions would result in a deviation and the emissions occurred during the fifth or subsequent cold-start of the unit during any 30-day period.
RMB reviewed the historical operating data presented for other “best performing” SCR retrofit installations. Many of these units also exhibited significant periods of 30-day averages in excess of 0.05 lb/mmBtu, which suggests that the FIP limit may not be an achievable limit even for the best performing units. PNM provided extensive comments on this issue based on an analysis conducted by Black and Veach (B&V). In EPA’s response, they do not fully address the concern that 0.05 lb/mmBtu was not consistently achieved over the entire evaluation period for each of the units. Rather, EPA references selected portions of the data where each of the units was consistently operating below the 0.05 lb/mmBtu level. An achievable limit is one that can be met during all periods of normal unit operation (excluding malfunctions). Even a single deviation for a well-controlled and operated source would suggest that the emissions limit is unachievable. The fact that EPA did not fully address all of the “exceedances” over the entire duration of each evaluation period suggests that their assessment of achievability is incomplete and flawed.

RMB notes that EPA offered a “partial response” to the issue by stating that some of the exceedances were outside of the ozone season when the SCR is not operating for some of the units. EPA further suggests that the historical operating data does not necessarily reflect the best performance of the units because many of them are not subject to ultra-low NOx emission limits. RMB notes that, while that may be true for some of the exceedances, many of them indeed occur within the ozone season (see Attachment A2) and, although the sources may not be subject to ultra-low emission limits, the plants have an economic incentive to minimize NOx emission during this time.

### Other Recently Permitted Units

RMB conducted a search of EPA’s RACT/BACT/LAER online database to identify similarly configured units (pulverized coal combustion with LNB and SCR) that were recently permitted with ultra-low NOx limits comparable to the FIP NOx limit. As shown in Table 6, the results included four units with heat-input based emissions limits ranging from 0.05 lb/mmBtu to 0.06 lb/mmBtu. All of the limits were issued for new construction. All of the units were issued secondary emissions limits that were based on either mass emissions rate (lb/hr) or heat input (lb/mmBtu) using a variety of averaging times (24-hour, 30-day rolling, 12-month rolling). RMB notes that none of the units were issued the same limit and compliance averaging time as the SJGS units. Furthermore, with the exception of Wygen Unit 3 and Dry Fork Station Unit 1, which were both permitted in Wyoming, none of the units are currently operational.

#### Wygen Unit 3 and Dry Fork Station Unit 1

Wygen Unit 3 and Dry Fork Station Unit 1 were both permitted in Wyoming and both burn subbituminous coal from the Powder River Basin (PRB), which tends to produce significantly lower NOx emissions. This reduces average emissions during operating periods with the SCR offline and presents an unfair bias in comparison to the units at SJGS because it also reduces overall emissions average during the averaging period. For Wygen Unit 3, the emission limits are not explicitly applicable during startup and shutdown periods. As for Dry Fork Station Unit

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7 There may be other permitted units not included in the EPA database.
1, the unit has been operational for only about two months, so the ability to meet the 12-month limit has not yet been demonstrated. Furthermore, the long-term nature of that averaging period provides substantially more compliance margin and operational flexibility than does the 30-day rolling average limit of 0.05 lb/mmBtu to which the FIP subjects the SJGS units. Thus, we do not consider that limit to be directly comparable to the FIP limits for SJGS.

Karn-Weadock Generating Complex

The Karn-Weadock Facility includes a proposed 930 MW supercritical PC-fired boiler. The unit was recently permitted with an emissions limit of 0.05 lb/mmBtu (30-day rolling average) that excludes SSM and a mass emissions limit of 409.5 lb/hour (24-hour rolling average) that includes SSM. The unit has not yet been constructed and it is not clear whether the utility will pursue construction of the unit at this time. Due to significant differences in boiler design and operation and the fact that the boiler has not yet been constructed, we do not consider the proposed limits suitable for comparison with the limits for SJGS.

Coleto Creek Power Station

Unit 2 at Coleto Creek Power Station is a proposed 650 MW supercritical PC-fired boiler. The unit was recently permitted with NOx emissions limits of 0.06 lb/mmBtu (30-day rolling average) and 0.05 lb/mmBtu (12-month rolling average), both of which exclude periods of startup and shutdown. RMB notes that these units are subject to an alternative work practice standard during startup and shutdown, which requires the plant to burn low-sulfur distillate oil and operate the unit in accordance with “good pollution control practices.” Due to significant differences in boiler design and operation, the fact that the boiler has not yet been constructed, and the long-term nature of the average period for the unit’s 0.05 lb/mmBtu limit, we do not consider the proposed limits suitable for comparison with the limits for SJGS.

Tenaska Trailblazer Energy Center

Tenaska Trailblazer Energy Center includes a proposed 750 MW supercritical PC-fired boiler. The unit was recently permitted with multiple heat-input based NOx emissions limits of 0.07 lb/mmBtu (24-hour average), 0.06 lb/mmBtu (30-day rolling average) and 0.05 lb/mmBtu (12-month rolling average). The unit was also issued multiple NOx mass emissions limits including 498 lb/hour (excluding SSM) and 1,661 lb/hour (including SSM), where both limits are based on a 30-day average. Due to significant differences in boiler design and operation, the fact that the boiler has not yet been constructed, and the long-term nature of the average period for the unit’s 0.05 lb/mmBtu limit, we do not consider the proposed limits suitable for comparison with the limits for SJGS.

Conclusions

RMB finds that the recently issued BACT limits do not support the FIP NOx limit for the units at SJGS. Although there have been several units permitted with generally similar emissions limits, none of these limits are directly equivalent (same numeric limit and averaging time, including startup and shutdown periods) to the FIP limit for SJGS. Furthermore, none of the units are suitable for comparison with the units at SJGS due to significant differences in boiler design. In addition, all of the above units are based on new construction, which, unlike retrofit units, can be
designed to optimize NO$_x$ reduction in other aspects of combustion (i.e. burner style, pulverizer design, boiler height, etc.). There is also inadequate data available to confirm the long-term achievability of the limits because the units have not begun operation or only recently became operational.

Based on our review of the available permits, these findings indicate that the FIP NO$_x$ limit issued for the units at SJGS represents the most stringent emission limit for any new or retrofit unit in the country. In addition, the fact that there are no similar units with a long-term operating history at such low emissions levels confirms that EPA failed to adequately consider the achievability of the FIP limit.
Table 5 – NO\textsubscript{x} Emission Limits for Selected Best Performing Retrofit Units

<table>
<thead>
<tr>
<th>Plant</th>
<th>Unit ID</th>
<th>Limit</th>
<th>Averaging Period</th>
<th>Applicable During Start-Up/ Shut Down?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Havana</td>
<td>9</td>
<td>0.10</td>
<td>lb/mmBtu</td>
<td>30-day rolling</td>
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<tr>
<td></td>
<td></td>
<td>0.50</td>
<td>lb/mmBtu</td>
<td>Annual</td>
</tr>
<tr>
<td>Mill Creek</td>
<td>3</td>
<td>0.52</td>
<td>lb/mmBtu</td>
<td>30-day rolling</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.70</td>
<td>lb/mmBtu</td>
<td>3-hour</td>
</tr>
<tr>
<td>Ghent</td>
<td>3</td>
<td>0.7</td>
<td>lb/mmBtu</td>
<td>3-hour</td>
</tr>
<tr>
<td></td>
<td>4</td>
<td>0.7</td>
<td>lb/mmBtu</td>
<td>3-hour</td>
</tr>
<tr>
<td>Chesterfield</td>
<td>6</td>
<td></td>
<td>NO\textsubscript{x} Allowance Trading Program</td>
<td></td>
</tr>
<tr>
<td>Amos</td>
<td>1</td>
<td></td>
<td>NO\textsubscript{x} Allowance Trading Program/ NO\textsubscript{x} Averaging Plan</td>
<td>0.46 lb/mmBtu (annual average)</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td></td>
<td>NO\textsubscript{x} Allowance Trading Program/ NO\textsubscript{x} Averaging Plan</td>
<td>0.46 lb/mmBtu (annual average)</td>
</tr>
</tbody>
</table>

\textsuperscript{8} But see Footnote Number 5.
<table>
<thead>
<tr>
<th>Permit Number/Date</th>
<th>Company</th>
<th>Plant</th>
<th>Unit ID</th>
<th>Limit</th>
<th>Averaging Period</th>
<th>Applicable During Start-Up/ Shut Down?</th>
<th>Notes</th>
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<tr>
<td>PSDTX1123 12/30/2010</td>
<td>Black Hills Corp.</td>
<td>Wygen</td>
<td>Unit 3</td>
<td>0.05</td>
<td>lb/mmBtu</td>
<td>12-month Rolling</td>
<td>No</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1.0</td>
<td>lb/MWh</td>
<td>30-day Rolling</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>65.0</td>
<td>lb/hr</td>
<td>30-day Rolling</td>
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<td></td>
<td>285</td>
<td>TPY</td>
<td>NA</td>
<td>No</td>
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<tr>
<td>CT-4517 02/05/2007</td>
<td>Tenaska Trailblazer Partners LLC</td>
<td>Tenaska Trailblazer Energy Center</td>
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<td>0.0500</td>
<td>lb/mmBtu</td>
<td>12-month Rolling</td>
<td>No</td>
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<td></td>
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<td></td>
<td></td>
<td>0.0600</td>
<td>lb/mmBtu</td>
<td>30-day Rolling</td>
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</tr>
<tr>
<td></td>
<td></td>
<td></td>
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<td>0.070</td>
<td>lb/mmBtu</td>
<td>24-hour Avg</td>
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<td>498</td>
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<td>30-day Avg</td>
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<td></td>
<td>1661</td>
<td>lb/hr</td>
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<tr>
<td>CT-4631 10/15/2007</td>
<td>Basin Electric Power Cooperative</td>
<td>Dry Fork Station</td>
<td>Unit 1</td>
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<td>lb/mmBtu</td>
<td>12-month rolling</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1.0</td>
<td>lb/MWh</td>
<td>30-day rolling</td>
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<tr>
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<td>190.1</td>
<td>lb/hr</td>
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<tr>
<td>PSDTX1118 05/03/2010</td>
<td>International Power</td>
<td>Coleto Creek</td>
<td>Unit 2</td>
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<td>lb/mmBtu</td>
<td>30-day Rolling</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>0.0500</td>
<td>lb/mmBtu</td>
<td>12-month Rolling</td>
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</tr>
<tr>
<td></td>
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<td>341-07 12/29/2009</td>
<td>Consumers Energy</td>
<td>Karn-Weadock</td>
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<td>0.0500</td>
<td>lb/mmBtu</td>
<td>30-day Rolling</td>
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</tr>
<tr>
<td></td>
<td></td>
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<td></td>
<td>409.5000</td>
<td>lb/hr</td>
<td>24-hour Rolling</td>
<td>Yes</td>
</tr>
</tbody>
</table>
ATTACHMENT A

Historical Operating Data for Best Performing SCR Retrofit Installations
Figure A1 – Historical 30-Day Rolling Average NOx Emissions for Havana Unit 9 (1/2008 – 11/2010) (Source: EPA)
Figure A2 – Historical 30-Day Rolling Average NOx Emissions for Ghent Unit 4 (1/2008 – 11/2010) (Source: EPA)
Attachment D

EPA, “Questions for AZ Regional Haze FIP Conference Call” (January 22, 2013)
1. Please explain the methodology finalized by EPA in the Arizona Regional Haze FIP ("Rule") for determining compliance with the NO\textsubscript{X} emissions limit (i.e. determining separate 30-day boiler operating day average emission rates per unit, and then averaging them across the facility).

First, we wish to clarify the use of certain terminology used in the Rule to describe the compliance methodology. While the NO\textsubscript{X} limits are described in the Rule as a "30-day (BOD) average," the compliance determination methodology does not actually require the mathematical averaging of lb/MMBtu values over a 30-day (BOD) period. Rather, it requires the NO\textsubscript{X} emission values (lbs) and heat input values (MMBtu) over a 30-day (BOD) period to be summed, producing a total NO\textsubscript{X} value and a total heat input value for each unit. We used the term "30-day (BOD) average" in the Rule in order to be descriptive of the fact that a 30 day (BOD) period is used as the basis to determine compliance, but it does not actually mathematically average emission or heat input values over the 30 day (BOD) period. Using this methodology provides less weight to those days which exhibit smaller amount of heat input (days with startup events) in relation to days which exhibit larger amounts of heat input (i.e., days of normal/full load operation). The attached spreadsheet (entitled "Response 1") includes the data set provided in question 9 as an example. In this spreadsheet, if the 30-day lb/MMBtu emission rate value is calculated using a mathematical average, each day's lb/MMBtu is given equal weight. This means that periods of cold startup, which exhibit high emissions but low heat input, are weighted equally (i.e., 1/30\textsuperscript{th} of the total) as periods of normal operation. The result is a 30-day value of 0.101 lb/MMBtu. By comparison, if calculated using the procedure described in the Rule, the values from cold startup days are given less weight because these periods exhibit less heat input. The result is a 30-day value of 0.062 lb/MMBtu, as calculated by the question submitter.

Similarly, while the NO\textsubscript{X} limits are described in the Rule as two-unit or three-unit averages, the compliance determination methodology does not actually require the mathematical averaging of lb/MMBtu values across units. Rather, as described in the previous paragraph, the Rule first requires that a 30-day (BOD) NO\textsubscript{X} total (lbs) and 30-day (BOD) heat input total (MMBtu) be calculated for each unit. The Rule then sums the NO\textsubscript{X} totals of the two units, sums the heat input totals of the two units, and then divides these two totals to produce a combined, two-unit lb/MMBtu value. Again, we use the
term "two-unit average" in order to be descriptive of the fact that compliance is
determined on a two-unit basis, but it does not involve mathematically averaging the
values from the two units. Use of this methodology allows the emission rates
(lb/MMBtu) from a unit operating under normal conditions for most of its 30-day (BOD)
period to mitigate the elevated emission rates (lb/MMBtu) from a sister unit that has gone
through one or more startup events over its 30-day (BOD) period. 1

The compliance determination methodology also uses the boiler operating day (BOD)
instead of the calendar day as the basis for the rolling 30-day period for calculating
emissions, consistent with the BART Guidelines. 2 Using the boiler operating day
generally mitigates the spikes in lb/MMBtu emission rates associated with startup events.
If calendar days are used, and a unit is offline for an outage that lasts longer than thirty
days, then the hours of operation on the boiler’s restart day following the outage would
be the only data recorded in the last thirty calendar days. Depending upon the time of
day that the unit was restarted and the duration of the startup, the emissions from the
startup event could represent the only data (or at least the majority of the data) recorded
in the last thirty calendar days. By using the boiler operating day, days of non-operation
are not included in the 30-day period. As a result, a startup following an outage of
greater than thirty days would not include 29 days of no data, but could instead rely on
the previous 29 operating days of data, which would mitigate the lb/MMBtu spike
associated with the startup event.

The compliance determination methodology also involves the use of a unit’s preceding
30-day (BOD) NOx emissions and heat input totals (during periods of the unit’s non-
operation) in calculating the multiple-unit lb/MMBtu emission rate. As described above,
establishing the emission limit across multiple units allows the emission rate (lb/MMBtu)
from a unit operating at steady state/normal conditions to mitigate the emission spike
from a sister unit operating at startup. If a calendar day approach were used instead of a
BOD approach, then, whenever a given unit was not operating, its sister unit(s) would be
required to meet the multi-unit emission limit by itself/themselves. By comparison, use of
BOD in combination with the multi-unit limit ensures that, whenever a given unit is not
operating, its sister unit(s) are not required to meet the multi-unit emission limit “by
itself/themselves.” Thus, for example, when one unit is not operating and a sister unit is
going through startup, the BOD approach allows the startup emission spike from the
operating unit to be mitigated by data from the shutdown unit(s).

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1 This type of multi-unit “averaging” was requested by the Arizona Utilities Group, on behalf of its members, for use
at Apache, Cholla and Coronado, during the public comment period on EPA’s proposed rulemaking.

2 40 CFR part 51, appendix Y, section V (“For EGUS, specify an averaging time of a 30-day rolling average, and
contain a definition of “boiler operating day” that is consistent with the definition in the proposed revisions to the
NSPS for utility boilers in 40 CFR Part 60, subpart Da. You should consider a boiler operating day to be any 24-
hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at
the steam generating unit. This would allow 30-day rolling average emission rates to be calculated consistently
across sources.”)
2. Regarding the NO\textsubscript{X} “bubble” calculation, are there any other permits, industries, or specific emission sources where EPA has established similar emission calculation procedures or methodology? If so, which rules and/or permits include this calculation?

It is helpful to distinguish between two elements of the compliance determination: the calculation of a lb/MMBtu emission rate across multiple units (the actual ‘bubble’), and the use of a unit’s preceding 30-day (BOD) NO\textsubscript{X} emissions and heat input totals (during periods of the unit’s non-operation) in calculating the plantwide/multiple-unit emission rate (lb/MMBtu).

**Element 1: Limit established across multiple units (the “bubble”)**

With regard to the first element, there are other examples of a production-weighted emission limit established across multiple units. Such a limit was established in the Nevada Regional Haze FIP for the Reid Gardner Generating Station\textsuperscript{3} and in the source-specific BART FIP for the Four Corners Power Plant.\textsuperscript{4} In addition, MACT Subpart AAAAA (Lime Manufacturing Plants) provides an option to demonstrate compliance with a PM emission limit by calculating a combined emission rate (lb/ton) across multiple kilns.\textsuperscript{5} Examples of facilities operating with this limit include the Chemical Lime plants in Nelson, AZ\textsuperscript{6}, Douglas, AZ, and the Apex Lime Plant in North Las Vegas, NV.

**Element 2: Use of an offline unit’s preceding 30-day totals**

With regard to the second element, the use of a non-operating unit’s preceding 30-BOD NO\textsubscript{X} emissions and heat input totals in calculating the multiple-unit lb/MMBtu emission rate, we are not aware of other permits or emission sources using the same methodology. As explained in response to the previous question, this methodology results from combining the use of BOD with a multiple-unit “average.”

3. Did EPA perform any modeling or assessments in developing the bubbling concept for NO\textsubscript{X} emissions in the Rule? If so, please provide the data and model, including any narrative or description of the modeling methodology and what model constraints and scenarios EPA used to evaluate the NO\textsubscript{X} limits and the applicability of this bubbling concept.

It is not clear what type of ‘modeling’ is referred to by the question. We did not perform any type of software modeling in developing the bubbling concept. However, we did examine data from the SRP Coronado Generating Station as reported to the Acid Rain Program for the period following installation of low-NO\textsubscript{X} burners to the end of September 2012. This information is included in the attached spreadsheet (entitled

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\textsuperscript{3} 77 FR 50952.
\textsuperscript{4} 77 FR 54647. We note that the limit for FCPP was established on a 30-calendar day (not BOD) basis, and on a plantwide basis. The alternative proposal established unit-specific limits for units 4 and 5 individually.
\textsuperscript{5} See 40 CFR 63.7112(f), and Option 4 of Table 1 of Subpart AAAAA.
\textsuperscript{6} Permit No. 42782, Specific Condition VI.7. We note, however, that compliance is demonstrated using a performance test, and not on a rolling basis using CEMS.
“Coronado 2011-12 NOx Emission Data (daily) BOD”). In this spreadsheet, lb/MMBtu emission rates were calculated using multiple methodologies, including on a rolling 30-calendar day basis and a rolling 30-day (BOD) basis for comparison. In addition, lb/MMBtu emission rates were calculated for individual units and on a multiple-unit basis for comparison.

4. **It appears there could be several scenarios in which this NOx “bubble” calculation would result in reporting emissions that are not representative of actual or recent emissions. Can EPA please explain how it considers the bubble calculation to be a representative depiction of actual emissions when different timeframes are being combined?**

The use of the boiler operating day instead of the calendar day as the basis for the rolling 30-day compliance period commonly entails the use of emission and heat input data from beyond the most recent 30 calendar days. In the case of an extended period of non-operation (for example, a 45 day outage), calculating the 30-day (BOD) emission rate would require the use of data from as far back as 75 calendar days in order to have 30 boiler operating days’ worth of data. Given the difference in operating profiles between multiple units (and the occurrence of multiple outages at a single unit over a short period of time), it will often be the case that the number of calendar days needed to obtain 30 boiler operating days’ worth of data will be different for each unit. By comparison, calculation of a multi-unit emission rate on a 30 calendar day basis would involve the use of data from the most recent 30 calendar days from all units, regardless of unit operation or non-operation.

5. **Please consider the following scenario: If a unit shuts down with the facility-wide NOx emission average at or near the established limit, but it appears that the unit would not be able to restart without exceeding the 30-day rolling average, how would EPA view the enforcement consequences of a decision to restart the unit? Would this constitute a “knowing” violation of the Rule?**

Whether or not this circumstance would be considered a “knowing” violation would depend upon the specific circumstances associated with this event, and is not something we can provide guidance on in this context.

6. **Please consider the following scenario: If a unit shuts down and then its sister unit(s) suffer an unanticipated shutdown or trip event, resulting in a prolonged restart which causes the emissions average to exceed the 30-day limit, can the company restart the first unit knowing its initial emissions will also exceed the limit, aggravating the exceedance, or must the company wait for the remaining unit(s) to return to compliance with an adequate margin of safety to accommodate the restart of the off-line unit? Would restart constitute a “knowing” violation of the Rule?**

The choice of when to restart the first unit lies with the company. The determination of whether or not this would be considered a “knowing” violation would depend upon the
specific circumstances associated with this event, and is not something we can provide guidance on in this context.

7. Please consider the following scenario: If a unit trips offline, and upon an attempted restart, trips again, causing an exceedance of the 30-day rolling average, can the operator proceed to restart that unit as soon as the problem is addressed in order to minimize the period of non-compliance? Or would the restart, which itself will cause an exceedance of the average, constitute a “knowing” violation of the Rule?

The choice of when to restart the unit lies with the company. Whether or not this would be considered a “knowing” violation would depend upon the specific circumstances associated with this event, and is not something we can provide guidance on in this context.

8. Please consider the following scenario: The units for a facility are operating at or below the “bubble” NO\textsubscript{X} limit established in the Rule. A situation arises where one of the units NO\textsubscript{X} performance begins to degrade, such that its individual performance on a 30-day basis exceeds the NO\textsubscript{X} performance average. The operator then proceeds to take this unit offline.

   a. If the NO\textsubscript{X} emissions from the “offending” (though still shutdown) unit cause the 30-day plant wide “bubble” to exceed the limit at the time of unit shutdown, is it an active violation for the operator/owner to continue to operate the other units, despite those units being below the established limit?

   It is unclear what is meant by “despite those units being below the established limit.” Since compliance is determined on a plant-wide basis, there is no “established limit” for individual units.

   b. Assume the plant-wide 30-day average NO\textsubscript{X} emission rate is below the limit established by the Rule at the time that the “offending” unit was taken offline. Now assume that the average NO\textsubscript{X} emission rate from the remaining “sister” unit(s) increases but the average NO\textsubscript{X} emission rate over the “sister” units remain below the 30-day plant wide “bubble” NO\textsubscript{X} limit. If inclusion of the last 30-day average NO\textsubscript{X} emission from the offending unit (that was previously shutdown) is included and this results in exceeding the facility’s “bubble” limit, is this considered an active violation even if the “offending” unit is not actually emitting anything?

   It is not clear what is meant by “the average NO\textsubscript{X} emission rate over the ‘sister’ units remain below the 30-day plant wide ‘bubble’ NO\textsubscript{X} limit.” Since the limit is calculated across all subject units is not possible to determine whether, for example, two of three subject units, are “below the 30-day plant wide ‘bubble’ NO\textsubscript{X} limit.”
9. Please consider the following scenario for Cholla Station, for which the Rule established a plant-wide 30-boiler-operating-day NO\textsubscript{X} emissions limit of 0.055 lb/MMBtu:

a. A unit is returning from an extended outage and commences to startup. Due to unforeseen complications, the unit remains in a cold startup condition resulting in only 12 boiler operating hours each of the first three days. On day four, the unit is in cold startup conditions for 12 hours and in normal operating conditions for the remaining 12 hours. Historical emissions data shows the NO\textsubscript{X} emission rate to be at 0.3 lb/mmBtu during startup conditions and the heat input of 1,200 mmBtu/hr. During full load conditions, it is assumed the unit is able to achieve a NO\textsubscript{X} emission rate of 0.045 lb/mmBtu when the SCR is in service and the heat input is assumed to be 3,000 mmBtu/hr. During this same 30-boiler-operating-day period, a scenario similar to days one through four occurs. The following NO\textsubscript{X} and heat input data represent the data that would be included in the calculation:

**NO\textsubscript{X} (mass)**

<table>
<thead>
<tr>
<th>Day</th>
<th>0.3 lb/mmBtu \times 1200 mmBtu/hr \times 12 hrs</th>
<th>0.045 lb/mmBtu \times 3000 mmBtu/hr \times 12 hrs</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4320 lbs</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>4320 lbs</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>4320 lbs</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>5940 lbs</td>
<td>68,040 lbs</td>
</tr>
<tr>
<td>5–25</td>
<td>68,040 lbs</td>
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<tr>
<td>26</td>
<td>4320 lbs</td>
<td></td>
</tr>
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<td>28</td>
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<tr>
<td>29</td>
<td>5940 lbs</td>
<td>3240 lbs</td>
</tr>
<tr>
<td>30</td>
<td>3240 lbs</td>
<td></td>
</tr>
</tbody>
</table>

Total NO\textsubscript{X} – 109,080 lbs

**Heat Input**

<table>
<thead>
<tr>
<th>Day</th>
<th>1200 mmBtu/hr \times 12 hrs</th>
<th>3000 mmBtu/hr \times 504 hrs</th>
<th>3000 mmBtu/hr \times 24 hrs</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>14,400 mmBtu</td>
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</tr>
<tr>
<td>2</td>
<td>14,400 mmBtu</td>
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<td>4</td>
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<td>1,512,000 mmBtu</td>
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</tr>
<tr>
<td>30</td>
<td>72000 mmBtu</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Total heat input – 1,771,200 mmBtu

109,080 lbs / 1,771,200 mmBtu = 0.062 lb/mmBtu
Based on this scenario, starting the unit near the end of the 30-boiler-operating-day period would result in a violation. It is understood that the NO\textsubscript{X} emission limit is based on the average of the group of boilers, but because of the substantially different baseline periods resulting from startup and shutdown scenarios, evaluating this “bubble” limit across an entire facility substantially complicates analysis.

In the situation shown above, what should the source do?

It is not clear to us that the premise of the situation described above—that starting the unit with its rolling 30-day emission rate at 0.062 lb/MMBtu would result in a violation—is a certainty. As the question notes, compliance is determined based upon the multi-unit emission rate (lb/MMBtu) and not on the emission rate of individual units.\(^7\) As a result, data from the other units must be known in order to determine if startup of the unit in question would indeed result in a violation.

In the example spreadsheet attached (entitled “Response 9”), the unit in question is assumed to be Cholla 3 (the data from the question has been input into the spreadsheet). To illustrate the calculation, the unit’s sister units have been represented as follows: Cholla 4 and Cholla 2 are both represented in the sample calculation as operating normally for the majority of its 30 boiler operating days. A small number of cold startups (duration varying between 4-12 hours) are included in each unit’s 30 boiler operating days, but with neither unit having experienced complications that require extended periods of cold startups. Based on these operating profiles for Cholla 2 and 4, the combined multi-unit emission rate is below 0.055 lb/MMBtu, even though the individual emission rate for Cholla 3 is 0.062 lb/MMBtu. Because the emission limit (lb/MMBtu) in the Rule is established across units, compliance is determined based upon the multi-unit emission rate (lb/MMBtu) and not on the emission rate of individual units. In this example, with operating profiles of the other units providing a sufficient margin, the restart of Cholla 3 would not cause the multi-unit emission rate to exceed the emission limit.

We realize that, in the example spreadsheet, the dates of the various emission points are generically labeled “day 1, day 2, etc.” As a result of the compliance determination methodology in the Rule, we realize these generically labeled days will correspond to different dates for each unit, and that identifying these dates for each unit involves additional complexity. As described in the response to question 1 and question 4, this is the result of the use of the boiler operating day, instead of the calendar day, as the basis for the 30-day limit. Without greater

\(^7\) We note that the methodology described in the final rule does not even involve calculation of rolling 30-day lb/MMBtu emission rates for individual units. While it involves calculating 30-day totals of NO\textsubscript{X} (lbs) and MMBtu for individual units, the 30 day totals of NO\textsubscript{X} (lbs) and MMBtu for the individual units are first summed to produce a three-unit total of NO\textsubscript{X} (lbs) and a three-unit total of heat input (MMBtu). These three unit totals are then divided to produce a single lb/MMBtu value.
detail regarding the data collection procedures and algorithms of the CEMS system used at each plant, we are not in a position to provide suggestions on how to resolve this issue.

Once the issue described above is resolved, and the appropriate 30-BOD totals of NOx (lbs) and heat input (MMBtu) are calculated for each unit, calculating the facility wide/multi-unit emission rate consists of summing the 30-BOD NOx totals, summing the 30-BOD heat input totals, and dividing those two sums to produce a single lb/MMBtu value.

10. The Rule is unclear with how data availability is addressed and utilized in the NOX “bubble” calculation. Please confirm that when the NOX lb/hr data is missing, both the NOX lb/hr data and the heat input (mmBtu/hr) are excluded from the “bubble” calculation (see 52.145(f)(5)(ii)(C) and (f)(6)(iii)(C)).

Yes. If NOx lb/hr data is missing for a particular hour, both the NOx emission data and heat input data for that hour are excluded from calculating the plantwide/multi-unit emission rate.

11. As described in AEPCO’s SIP submittals and in ADEQ’s technical description of their facility, AEPCO exhausts emissions from a BART-eligible unit (Steam Unit 1 – ST1) and a non-BART-eligible unit (simple cycle turbine GT1) through the same stack. AEPCO’s CEMS is located in the combined stack. Can EPA explain how AEPCO should account for emissions from GT1 in demonstrating compliance with the limits established in the Rule (see 52.145(f)(3)(ii)(B)) for the BART-eligible unit?

EPA approved ADEQ’s BART determinations for NOx, SO2 and PM10 at AEPCO Apache Unit 1, as set forth in ADEQ’s Regional Haze SIP and did not establish any new limits for this unit. See 40 CFR § 52.120(c)(154)(ii)(A)(I)(i). Specifically, with regard to NOx at Unit 1, ADEQ determined that BART is the installation of LNB with Flu Gas Recirculation (FGR) with an emissions limit of 0.056 lb/MMBtu. In its comments on ADEQ’s SIP, AEPCO stated that, “Since the normal operation of this unit is combined cycle with gas turbine 1 (GT1), AEPCO would like to propose combustion with PNG only, in combined cycle operation with all exhaust gas from GT1 recirculated into ST1 (the combined cycle operating configuration represents FGR), and installation of LNB as BART.” Therefore, it appears that ST1 can only meet the BART requirements of the SIP when operated in combined cycle mode with GT1. Under the BART Guidelines, combined cycle turbines are considered “steam electric plants.” Accordingly, combined cycle turbines that are part of a fossil-fuel fired steam electric plant of more than 250 million Btu/hour heat input are BART-eligible. Thus, based on the information in the SIP, it seems that GT1 is, in fact, part of the BART-eligible unit, so its emissions should be included in determining compliance. However, additional information from AEPCO and ADEQ may be needed to address this question.
12. The Rule requires (see 52.145(f)(6)) that

“In addition to annual stack tests, the owner/operator shall monitor particulate emissions for compliance with the emissions limitations in accordance with the applicable Compliance Assurance Monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64.”

a. Does this require that each owner/operator submit new or revised CAM plans?

For a particular pollutant-specific emission unit, CAM is intended to provide reasonable assurance of compliance with emission limits or standards for that unit. If the current CAM plan will reasonably assure compliance with the new particulate matter limits in the FIP, there is no requirement to submit a new or revised CAM plan. Because EPA or ADEQ may require owners and operators of equipment subject to CAM to implement a Quality Improvement Plan (QIP) when the plan is found to be inadequate, we encourage the owner/operators to examine whether their existing CAM plans and the monitoring conditions in their current Title V operating permits are adequate. If not, the CAM plan may be modified as part of the next renewal application or a significant permit revision.

b. If a new CAM plan is required, who should the CAM plans be submitted to – ADEQ (as the Title V authority) or EPA?

As part of an application for a Title V permit renewal or significant revision, CAM plans must be submitted to the permitting authority, ADEQ. ADEQ must then either transmit the application, including the CAM plan, to EPA, or require the applicant to submit the application and plan to EPA directly. Because EPA will object to Title V permits and significant revisions issued by states when they are not in compliance with applicable requirements, we strongly recommend that ADEQ and permit applicants include EPA in CAM plan review.

c. If a new CAM plan is required, what is the deadline for submitting the CAM plan? Is the deadline for submitting the CAM plan the PM10 compliance date established in the Rule (see 52.145(f)(3)(ii))?  

The deadline for submitting a new or revised CAM plan, if one is required, is with an application for an initial title V permit, a permit renewal, or significant revision as required by 40 CFR 64.5. If the owner or operator believes that an existing

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8 Pollutant-specific emissions unit means an emissions unit considered separately with respect to each regulated air pollutant. 40 CFR 64.1.
9 40 CFR 64.3(a).
10 40 CFR 64.8(a).
11 40 CFR 64.4, 64.5.
12 40 CFR 70.8(a), 40 CFR 70.7(e)(4)(ii).
13 40 CFR 70.8(c)(1).
CAM plan will need to be revised in order to avoid being required to develop a QIP, an application for a significant revision may be submitted at any time.

d. Does EPA interpret this language to suggest that PM compliance will be determined by the CAM plan as well as the annual performance tests?

The Act requires the Administrator to use any information available, including, but not limited to, the results of required monitoring and testing, to determine whether a person is in violation of any requirement of an implementation plan.\(^\text{14}\)

13. Under 52.145(f)(11)(iii), should the reports be directed to EPA Region 9 or to ADEQ? If reports are directed to Region IX, what is the legal basis for substituting a Region 9 person for ADEQ?

Unless otherwise directed, the reports should be sent to ADEQ, as required under R18-2-310.01.

14. Given that the Rule requires compliance with the emission limits based on a 30-boiler-operating-day average, is the compliance date identified in the Rule (see 52.145(f)(4)) the first day or the last day of the initial 30-boiler-operating-day compliance period?

The compliance dates identified in the Rule correspond to the first day of the initial 30-day (BOD) compliance period for each applicable emissions limit.

15. In addition to the current relative accuracy test audit requirements for the utility units imposed by 40 CFR Part 75, the Rule requires NO\(_x\) and SO\(_2\) relative accuracy audit tests to be conducted for the NO\(_x\) and SO\(_2\) measurements (in lbs/hr) and the heat input measurements (in MMBtu/hr). Can EPA provide information regarding the purpose of these extra quality assurance testing requirements, as well as guidance regarding what specific relative accuracy standard should be used for this testing?

Measurement and quality assurance (QA) requirements for NOx lb/hour are not currently required by 40 CFR Part 75. Since the NOx emission limit is in units of lb/MMBtu, these additional relative accuracy test audit (RATA) requirements for NOx and heat input are intended to provide us with a means to gauge the accuracy of the monitored emissions.

In the proposed rule, we proposed that the RATAs for NOx lb/hr measurement and heat input measurement have relative accuracies of 20\%. As a result of submitted comments, this element of the proposal was not included in the final rule. Therefore, there is no relative accuracy standard that should be used for testing.

\(^{14}\) CAA 113(a)(1), 42 U.S.C. 7413(a)(1).
16. The Rule requires an annual performance stack test to determine compliance with the PM emission limit within 60 days of the specified compliance deadline. Is the 60-day period measure in boiler-operating-days or calendar days? Does this requirement mean the compliance test can be performed within 60 days prior to the compliance date or 60 days after the compliance date or either?

The requirement means that the compliance test must be performed within the 60 calendar days following the compliance date.
Attachment E

Sargent & Lundy LLC, Salt River Project
Coronado Generating Station Unit 2 SCR
Review: Final Report SL-011433
(August 24, 2012)
Salt River Project
Coronado Generating Station Unit 2 SCR Review

CONTRIBUTORS

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Approved by:

Rajendra Gaikwad
Vice President, Environmental Technologies

8/24/12
August 24, 2012

8/24/12
August 24, 2012
Executive Summary

Salt River Project (SRP) plans to install a selective catalytic reduction (SCR) nitrogen oxide (NOx) control system on its Coronado Generating Station (CGS) Unit 2. The Unit 2 SCR control system, which has been engineered, designed, and is currently being fabricated for installation, was designed to achieve an enforceable permit limit of 0.080 pounds per million British thermal units (lb/MMBtu) on a 30-day rolling average, applicable at all times including periods of unit cycling, startup, and shutdown.

As part of the Arizona Regional Haze rulemaking process, the U.S. Environmental Protection Agency (EPA) Region IX requested further documentation from SRP regarding the technical feasibility and costs associated with reducing the Unit 2 NOx emission limit from 0.080 lb/MMBtu to 0.050 lb/MMBtu (30-day rolling average). In response to EPA’s request for additional information, SRP requested that Sargent & Lundy LLC (S&L): (1) evaluate CGS Unit 2 operating data to determine the feasibility of meeting a controlled NOx emission limit of 0.050 lb/MMBtu (30-day rolling average) including periods of unit cycling, startup, and shutdown; and (2) identify physical and operational changes to the current SCR design that may allow SRP to meet an enforceable NOx emission limit more stringent than its current limit of 0.080 lb/MMBtu (30-day rolling average).

To address these questions, S&L modeled expected NOx emissions from CGS Unit 2 by applying NOx removal efficiencies based on the current SCR design to historical Unit 2 operating data. NOx emissions were modeled for several operating scenarios, including full load operation, high-load cycling, low-load cycling, unit startups and shutdowns. Based on emissions modeling, S&L found the following:

a. The CGS Unit 2 SCR control system, as currently designed, can achieve a controlled NOx emission rate of 0.080 lb/MMBtu (30-day rolling average) including periods of unit cycling, startups, and shutdown.
b. The CGS Unit 2 SCR control system, as currently designed, cannot meet an emission limit of 0.050 lb/MMBtu (30-day rolling average) due to unit cycling, startups, and shutdowns.

c. At a minimum, SRP would be required to install a low-load temperature control system designed to increase flue gas temperatures at the SCR inlet during periods of low-load cycling to achieve any additional reduction in average NOx emissions.

d. Emissions modeling showed that even with the addition of a low-load temperature control system, the CGS Unit 2 SCR could not meet an emission limit of 0.050 lb/MMBtu (30-day rolling average) due to low-load cycling and unit startups.

e. Additional catalyst would have to be added to the SCR reactor box to achieve additional NOx reductions. Consequences of increasing the catalyst volume include, but are not necessarily limited to, increased pressure drop across the SCR, increased sulfur-dioxide (SO₂) to sulfur-trioxide (SO₃) oxidation, and increased sulfuric acid mist formation and condensable particulate matter (PM) emissions.

f. Increasing the catalyst volume in the SCR significantly increases the likelihood that SRP would be required to install a dry sorbent injection (DSI) control system to reduce sulfuric acid mist emissions.

g. In the event particulate matter (PM) emissions generated in the SCR and DSI control systems are not effectively captured in the unit’s existing wet flue gas desulfurization (FGD) control system, SRP would also be required to install a fabric filter baghouse control system to meet its PM emissions limit.

h. Capital costs associated with control system modifications vary significantly depending on the control systems needed to address increased sulfuric acid mist and particulate matter emissions, but are expected to range from a minimum of $8,350,000 (including the additional catalyst, low-load temperature control system, and DSI control system, but no fabric filter baghouse) to as much as $117,850,000 (including a fabric filter baghouse).

i. Increased operating and maintenance (O&M) costs will also be incurred to operate the SCR control system to achieve lower NOx emissions, and are expected to range from a minimum of $1,461,000/yr (including the additional catalyst, increased ammonia consumption, and operation of the DSI control system, but no baghouse) to as much as $3,881,000/yr (with the baghouse).
ABBREVIATIONS AND ACRONYMS

<table>
<thead>
<tr>
<th>Abbreviation or Acronym</th>
<th>Explanation</th>
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<tbody>
<tr>
<td>BART</td>
<td>Best Available Retrofit Technology</td>
</tr>
<tr>
<td>BOP</td>
<td>Balance of Plant</td>
</tr>
<tr>
<td>Btu</td>
<td>British thermal unit</td>
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<td>Continuous Emissions Monitoring System</td>
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Introduction

On July 20, 2012, the U.S. EPA published a rule proposing to approve in part and disapprove in part a revision to Arizona’s State Implementation Plan (SIP) to implement the regional haze program. The proposed Regional Haze Federal Implementation Plan for the state of Arizona (referred to as the “Proposed RH FIP”) addressed provisions in the SIP related to Arizona’s determination of Best Available Retrofit Technology (BART) at three generating stations, including CGS. In the Proposed RH FIP, EPA proposed a NOx BART emission limit for Coronado Unit 2 of 0.080 lb/MMBtu (30-day rolling average). This emission rate is consistent with the NOx emission rate Coronado Unit 2 is required to achieve pursuant to an August 12, 2008 consent decree entered into between SRP and EPA.

In the Proposed RH FIP, EPA noted that it was evaluating a more stringent NOx BART emission limit for Coronado Unit 2, and EPA calculated the cost-effectiveness of reducing NOx emissions from 0.080 lb/MMBtu to 0.050 lb/MMBtu. EPA calculated an incremental cost-effectiveness for the 0.050 lb/MMBtu option of $583/ton, which it concluded made “it a control option that we would consider cost-effective.” (77 Fed. Reg. 42863, col. 1). However, EPA acknowledged that it had received information from SRP indicating that design and construction of the Unit 2 SCR was well under way, and SRP identified several significant costs that may be incurred if it were required to re-design the SCR to achieve the lower emission rate. Since these additional costs were not factored into EPA’s original cost-effectiveness analysis, EPA acknowledged that the incremental cost-effectiveness of requiring Coronado Unit 2 to meet an emission limit of 0.050 lb/MMBtu may in fact be greater than indicated by its analysis. EPA noted that it intended to request further documentation in order to determine the extent of these costs and how they would affect the cost-effectiveness of the SCR control system.

In a letter to SRP from EPA Region IX dated July 27, 2012, EPA stated that before it could incorporate these considerations into a final BART analysis for Coronado Unit 2, further documentation was needed regarding both the technical feasibility and cost of meeting the lower limit. Information specifically requested by EPA in its July 27, 2012 letter included documentation of the design changes to the SCR that would be needed to meet a limit of 0.050 lb/MMBtu for NOx at Unit 2.
In response to EPA’s request for information, SRP authorized S&L to perform the following tasks:

Task 1: Evaluate Coronado Unit 2 operating data to determine the feasibility of meeting a controlled NOx emission limit of 0.050 lb/MMBtu (30-day rolling average) given the current SCR control system design; and

Task 2: Evaluate changes to the current SCR design to achieve a more stringent NOx emissions limit.

To complete these tasks, S&L modeled expected NOx emissions from CGS Unit 2 by applying NOx removal efficiencies based on the current SCR design to historical Unit 2 operating data. NOx emissions were modeled for several operating scenarios, including full load operation, high-load cycling, low-load cycling, unit startups and shutdowns. Based on the results of the NOx emissions modeling, S&L reviewed the design changes that would be needed to achieve additional NOx emission reductions, taking into consideration that engineering and design of the Unit 2 SCR is complete. S&L’s evaluation focused on changes that could be incorporated into the existing SCR design without changing the physical size of the control system, affecting CGS’ planned maintenance cycle, or requiring re-design of the structural steel, foundations, and balance-of-plant (BOP) tie-ins.

This report provides the results of S&L’s evaluation.
ANALYSIS

Task 1: Evaluate Feasibility of Meeting a Controlled NOx Emission Limit of 0.050 lb/MMBtu

S&L was asked to evaluate the feasibility of meeting a controlled NOx emission limit of 0.050 lb/MMBtu (30-day rolling average) given the current design of the CGS Unit 2 SCR control system. The Unit 2 SCR control system, which has been engineered, designed, and is currently being fabricated for installation, was designed to achieve an enforceable permit limit of 0.080 lb/MMBtu (30-day rolling average) applicable at all times including periods of unit cycling, startup, and shutdown.

In order to meet an enforceable NOx emission limit of 0.080 lb/MMBtu, the existing SCR control system for CGS Unit 2 is designed to achieve a target NOx emission rate of 0.040 lb/MMBtu at full load steady state conditions, at an average inlet NOx emission rate in the range of 0.32 lb/MMBtu and short-term inlet NOx rate of 0.39 lb/MMBtu. The ammonia (NH₃) injection system was designed to provide NH₃ based on the NOx removal rates described above. Catalyst volume was determined by the SCR vendor to achieve a full load steady state guarantee value NOx emission rate of 0.040 lb/MMBtu with an NH₃ slip of 2 parts per million (ppm) at 25,000 hours catalyst life. The full load guarantee value NOx emission rate provided by the SCR vendor does not include periods of startup, shutdown, or cycling.

SCR control systems require a minimum flue gas temperature of approximately 600 °F for effective NOx reduction. At temperatures below 600 °F, including periods of unit startup, shutdown, cycling at low loads, and malfunction, flue gas temperatures may not be high enough for effective NOx control. Because SCR control systems do not provide effective NOx control at these operating conditions, the SCR must be designed to achieve a full load guarantee value NOx emission rate below the enforceable permit limit to allow for periods of startup, shutdown, and cycling.

To evaluate the feasibility of achieving an enforceable NOx emission rate of 0.050 lb/MMBtu, S&L analyzed the most recent eighteen months of available CGS Unit 1 and 2 operating data. Existing operating data was evaluated to quantify the affect of unit cycling, startup, and shutdown on the controlled NOx emission rate over a 30-day period. To do this, S&L used existing NOx emissions
data and flue gas temperatures at the air preheater to calculate: (1) expected full load NOx emissions with the SCR; (2) expected NOx emissions with Unit 2 operating in a cycling mode ranging from a minimum load of 138 MW-gross output (MWg) up to full load on a daily basis; and (3) expected NOx emissions on a 30-day rolling average taking into consideration unit startups and shutdowns.

Load profiles were generated for CGS Units 1 and 2 using operating data from January 2011 through July 2012. Load profile data, NOx emissions, and flue gas temperature data for CGS Unit 1 was provided by SRP, amassed from the unit’s data collection system. Load profile data and NOx emissions for CGS Unit 2 were generated using continuous emissions monitoring system (CEMS) data reported to the EPA’s Clean Air Markets Program Database, and correlated to flue gas temperature data available from the unit’s data collection system. Graphs showing the Unit 1 and Unit 2 load profiles are included in Attachments 1a and 1b, respectively. The load profile graphs in Attachments 1a and 1b show periods of start-up and shutdown, as well as frequent cycling of the units.

Load profiles developed for CGS Units 1 & 2 were used to predict NOx emissions after the installation of the SCR control system on Unit 2. Two NOx emission scenarios were evaluated. The first scenario included installation of the SCR only. The second scenario included both the SCR and a low-load flue gas temperature control system.

The purpose of the low-load flue gas temperature control system would be to increase flue gas temperatures at the SCR inlet to approximately 600 °F during periods of low-load cycling, startup, and shutdown. A minimum SCR operating temperature is required to avoid the formation of ammonium salts, primarily ammonium sulfate/bisulfate, which is formed by the reaction of SO3 and unreacted NH3. Ammonium salt deposition can blind the catalyst surface, and result in a significant reduction in catalyst activity and NOx removal performance. Ammonium salt formation can only be avoided by operating the SCR system above the formation temperature or by halting the injection of NH3 when temperatures are below design levels. The guaranteed Unit 2 SCR low operating temperature is 599 °F.

In the first scenario, the use of the SCR was limited to those data points where the measured air preheater temperature was greater than 599 °F, the inlet temperature needed for effective NOx control guaranteed by the SCR original equipment manufacturer (OEM). Operating data indicate that an air
preheater temperature of 599 °F corresponds to a steam turbine generator outlet of approximately 270 MWg. NOx emissions associated with the SCR-only scenario were calculated for two load cycling profiles (described below).

In the second scenario, the use of the SCR was again limited to those data points where the minimum required temperature was achieved. However, since this scenario included a low-load temperature control system, minimum inlet temperatures to the SCR could be achieved for loads down to approximately 138 MWg, assuming the unit had enough operating hours to provide flue gas heating. As with the first scenario, NOx emissions with the SCR plus low-load temperature control system scenario were calculated for two load cycling profiles (described below).

**Task 1: Load Cycling Profiles**

NOx emissions from CGS Unit 2 were modeled for two load cycling profiles. Cycling profiles used for the NOx evaluation are shown in Attachments 2, 3 and 4.

The first cycling profile is based on load data from mid January 2012 to early March 2012. During the winter Unit 2 typically operates above 270 MWg and the unit cycles between approximately 60% and 100% of its full load. This load profile is referred to as the “high-load cycling” profile. A detailed load profile for this period is shown in Attachment 3. Continuous operation above 270 MWg would allow the unit to operate the SCR without use of a low-load temperature control system, as temperatures at the SCR inlet typically remain at or above 599 °F. NOx emissions during the high-load cycling profile were calculated based on the following assumptions:

a. NOx emissions will be controlled to 0.050 lb/MMBtu when the unit is increasing in load due to the lag in the delivery of additional ammonia and adsorption on the catalyst.

b. NOx emissions will be controlled to 0.040 lb/MMBtu when the unit is decreasing in load due to the residual ammonia on the catalyst surface.

c. The SCR will provide no additional NOx control, beyond that provided by the low-NOx burners (i.e., 0.320 lb/MMBtu average), when the unit is operating below 270 MWg.

The second cycling profile analyzed for Unit 2 occurred from mid March 2012 to the beginning of May 2012. Unit loads during this period of time ranged from approximately 138 MWg to full
load; therefore, this load profile is referred to as the “low-load cycling” profile. A detailed load profile for this period is shown in Attachment 4. During a low-load cycling period the unit will not consistently operate above 270 MWg, and economizer outlet temperatures will drop below the required 599 °F for effective NOx control. Without using a low-load temperature control system to increase flue gas temperature at the SCR inlet, ammonia feed to the SCR will be shut off whenever the unit drops below 270 MWg to prevent the formation of ammonium salts. NOx emissions during the low-load cycling profile were calculated based on the same assumptions used for the high-load profile.

**Task 1: Load Cycling Profiles - Results**

NOx emission rates developed from the high- and low-load cycling scenarios were used to model the 30-day rolling average NOx emissions rate for CGS Unit 2. In accordance with the monitoring and recordkeeping requirements in the CGS’ Title V Operating Permit (Permit No. 52639), the 30-day rolling average was calculated by dividing the total NOx emitted (in pounds during the last 30 unit operating days) by the total heat input (in MMBtu/hr during the last 30 unit operating days). Days where no heat input to the boiler was reported were excluded from the calculation (i.e., they were not considered operating days). Calculations were performed based on the reported load profile for Unit 2. In addition, calculations were performed based on the load profile for Unit 1, but using the modeled NOx emissions from Unit 2.

Graphs showing the modeled 30-day rolling average NOx emissions are included in Attachments 5a and 5b. Attachment 5a shows the 30-day rolling average NOx emissions using the Unit 1 load profile and the modeled Unit 2 NOx emission rates. Attachment 5b shows the 30-day rolling average NOx emissions using the Unit 2 load profile and the modeled Unit 2 NOx emission rates.

It can be seen from the emission calculations summarized in Attachments 5a and 5b, that CGS Unit 2 would meet a controlled NOx emission rate of 0.080 lb/MMBtu (30-day rolling average) without installing a low-load temperature control system under practically all operating scenarios, including periods of startup and shutdown. The only period of time modeled NOx emissions exceed 0.080 lb/MMBtu (30-day rolling average) occur during short periods of time when the unit cycled extensively at loads below 270 MWg coupled with a unit shutdown/startup. SRP could
respond to these periods by increasing NH₃ injection to the SCR control system for short periods of time, or by cycling the other CGS unit (Unit 1) instead. However, NH₃ injection rates could not be increased for extended periods of time due to the increased potential for ammonium bisulfate formation, catalyst blinding, and air preheater plugging.

Modeled NOx emissions shown in Attachments 5a and 5b also indicate that Unit 2 NOx emissions would exceed 0.050 lb/MMBtu (30-day rolling average) for extended periods of time without the low-load temperature control system. It is apparent that SRP would have to design, install, and operate a low-load flue gas temperature control system to meet any permit limit more stringent than the current limit of 0.080 lb/MMBtu. Even with the low-load temperature control system, modeled NOx emissions exceed 0.050 lb/MMBtu (30-day rolling average) during periods of low-load cycling (i.e., when the unit cycles below approximately 138 MWg) and during periods of frequent outages. This can be seen graphically in Attachment 5a for a 30-day period in mid-2011 and in Attachment 5b for a 30-day period around April 2012. Comparing these periods with the load profiles in Attachments 1a and 1b, it can be seen that during these periods the unit was frequently cycling from full load down to loads as low as 100 MWg and that an outage was taken.

**Task 1: Startup Profiles**

Startup profiles were also modeled to determine how unit startups affect the 30-day rolling average NOx emissions rate. Number 2 fuel oil is used as the initial startup fuel for GGS Unit 2 to warm the boiler and turbine. Once the boiler and turbine are sufficiently warm, the first mill is brought on-line and coal is introduced to the boiler. Coal and fuel oil are co-fired, primarily for flame stability, as the unit is ramped up to approximately 150 MWg, at which point the unit will fire coal exclusively, and the unit is ramped up to full load. During unit startup, ammonia injection cannot occur until flue gas temperatures at the SCR inlet reach 599 °F. The SCR would provide no additional NOx control prior to reaching sufficient flue gas temperature.

NOx emissions during startup were modeled based on the Unit 2 startup profile shown in Attachment 6. Two startup periods were modeled: (1) starting with initial fuel oil firing and ending when the first mill is brought on-line and coal is introduced to the boiler; and (2) starting with initial coal firing and ending when the economizer outlet temperature reaches 599 °F.
Based on the startup profile shown in Attachment 6 for a cold startup (defined as greater than 96 hours off-line), fuel oil is fired exclusively for approximately 18 to 22 hours before coal is introduced to the boiler. This period of time will be shorter, in the range of 8 to 10 hours, for a warm unit restart (defined as less than 48 hours off-line). Startup continues for an additional 10 to 12 hours following initial coal firing to reach 270 MWg output and an air heater outlet temperature of 599 °F. This period of time will be shorter for a warm restart. Total startup time, from initial oil firing to 270 MWg output (assuming no operating issues, unit trips, or restarts) ranges from 30 to approximately 36 hours.

NOx emissions were modeled for both startup periods based on the load (MWg), temperature (°F), and NOx emissions data (lb/MMBtu) shown in Attachment 6. Heat input-weighted average NOx emission rates were determined for each startup period by dividing total NOx emitted during the startup period (in pounds) by the total heat input (in MMBtu) over that time period. During the first period the unit had a heat input-weighted average NOx emission rate of 0.145 lb/MMBtu per hour. During the second period the unit had a heat input-weighted average NOx emission rate of 0.289 lb/MMBtu per hour. These heat input-weighted average emission rates were used to model the effect of unit startups on the 30-day rolling average NOx emission rate.

**Task 1: Shutdown Profiles**

Shutdown profiles were also modeled to determine how unit shutdowns affect the 30-day rolling average NOx emissions rate. During unit shutdown ammonia injection would cease once flue gas temperatures at the SCR inlet drop below 599 °F. CGS Unit 2 shutdown profiles were analyzed using 15-minute SRP supplied operating data. Unit 2 shutdown data, shown graphically in Attachment 7 (May 3 – May 5, 2012), were used to profile NOx emissions during a unit shutdown.

Analysis of the shutdown data, including unit load (MWg), air heater inlet temperature (°F), and NOx emission rate (lb/MMBtu), reveals that the air heater inlet temperature stays above 599 °F from the point of unit turndown until the unit reaches a load approaching 138 MWg. Once the air heater inlet temperature is below 599 °F, the SCR will not provide effective NOx control.

NOx emissions were modeled at 0.040 lb/MMBtu during initial turndown of the boiler (based on the assumptions listed above for the cycling profiles). From the period of time that the air heater
inlet temperature is below 599 °F (approximately 138 MWg) until the unit is no longer producing power (0 MW), NOx emissions averaged approximately 0.277 lb/MMBtu. This emission rate continues for approximately 2 to 2.5 hours as the unit turns down from 138 to 0 MW.

It was also determined that there would be no significant difference in NOx emissions during a unit shutdown for the SCR plus low-load temperature control system scenario. Although the low-load temperature control system may allow the SCR to operate at somewhat lower loads during shutdown, there is a threshold below which NH₃ injection to the SCR would have to cease. As determined in the low-load cycling profile analysis, flue gas temperatures at the SCR inlet will drop below 599 °F at approximately 138 MWg even with the low-load temperature control system. Therefore, even with the low-load temperature control system, NOx emissions will average approximately 0.277 lb/MMBtu for the 2 to 2.5 hour period as the unit ramps down from 138 to 0 MW.

Task 1: Startup/Shutdown Profile Results

To quantify the potential impact of unit startups and shutdowns on the 30-day rolling average NOx emission rate, S&L modeled NOx emissions over a 30-day period based on the following assumptions:

a. NOx emissions were modeled using the calculated heat input-weighted average NOx emission rates for each startup period and using the startup durations shown in Attachment 6.

b. To account for all typical operating scenarios, for the remainder of the 30-day period S&L assumed Unit 2 would operate in a low-load cycling mode.

A 30-day rolling average NOx emission rate was calculated assuming one, two, and three startups within a 30-day operating period. As expected, the number of starts in a given 30-operating day period had a significant affect on the calculated 30-day rolling average NOx emissions rate. Startup emission impacts were modeled for the SCR only scenario (i.e., no low-load temperature control system) and the SCR combined with a low-load temperature control system scenario. Results of the startup evaluations are summarized in Table 1.
Table 1
30-Day Rolling Average Including Unit Startups*

<table>
<thead>
<tr>
<th>Modeled Scenario</th>
<th>1 Start Per 30 Operating Days</th>
<th>2 Starts Per 30 Operating Days</th>
<th>3 Starts Per 30 Operating Days</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCR with no low-load temperature control system</td>
<td>0.075 lb/MMBtu</td>
<td>0.083 lb/MMBtu</td>
<td>0.091 lb/MMBtu</td>
</tr>
<tr>
<td>SCR with a low-load temperature control system</td>
<td>0.053 lb/MMBtu</td>
<td>0.063 lb/MMBtu</td>
<td>0.072 lb/MMBtu</td>
</tr>
</tbody>
</table>

* NOx emissions for the remainder of the 30-day operating period were modeled based on the low-load cycling scenario. 30-day rolling average emission rates will vary somewhat depending on the time of day unit startup begins.

Results summarized in Table 1 are based on the 34-hour startup profile shown in Attachment 6. It should be noted that more significant impacts to the 30-day rolling average NOx emission rate would occur for a longer startup, or if the boiler trips during startup requiring a second startup within a short period of time. Such a scenario would not be unusual for a large coal-fired boiler. For example, plant operating data from CGS Unit 1 from April 12-15, 2012 shows an extended startup period with two starts. For that specific startup, air heater gas inlet temperatures did not reach 599 °F for approximately 94 hours after initial coal firing. S&L did not model impacts associated with longer startup times, however higher 30 day-rolling average NOx emissions would result from these longer startup times.

Task 1: Summary of Results

Based upon the analyses performed, CGS Unit 2 would be expected to meet its existing permit limit of 0.080 lb/MMBtu (30-day rolling average) under practically all operating scenarios, including periods of startup and shutdown. The only periods of time modeled NOx emissions exceed 0.080 lb/MMBtu (30-day rolling average) occur during short periods of time when the unit cycled extensively at loads below 270 MWg coupled with a unit shutdown/startup. SRP could respond to these periods by increasing NH₃ injection to the SCR for short periods of time. Thus, including periods of startup and shutdown, CGS Unit 2 would be expected to comply with an emission limit of 0.080 lb/MMBtu (30-day rolling average) with the SCR and no low-load temperature control system.
A low-load temperature control system would be required to comply with a more stringent NOx emission limit. Even with a low-load temperature control system, modeled NOx emissions from CGS Unit 2 exceed 0.050 lb/MMBtu (30-day rolling average) when periods of low-load cycling and startup are taken into consideration.

**Task 2: Evaluate Changes to the Current SCR Design to Achieve a More Stringent NOx Emission Limit**

Task 2 included an evaluation of the design and operational changes that SRP would need to consider implementing to achieve a more stringent NOx emission limit. Based on the NOx emissions modeling completed in Task 1, SRP would need to modify the current design of the Unit 2 SCR control system to accept any enforceable permit limit below the current limit of 0.080 lb/MMBtu (30-day rolling average).

As an initial change, SRP would have to design, install, and operate a low-load temperature control system to allow the SCR control system to operate at lower loads. In addition, SRP would have to obtain a guarantee from the SCR OEM for a full load steady state guarantee value of 0.030 lb/MMBtu in lieu of the current 0.040 lb/MMBtu guarantee. Based on S&L’s evaluation of historical CGS Unit 1 & 2 operating data, the following design changes would have to be evaluated and implemented, if available, to obtain the more stringent full load NOx guarantee value:

a. Add additional catalyst to the existing reactor box and increase the NH₃ injection rate in an effort to achieve a full load guarantee value NOx emission rate of 0.030 lb/MMBtu.

b. Maintain the catalyst life at 25,000 hours with 2 ppm NH₃ slip at the end of the catalyst life to correspond with the unit’s planned outage schedule.

c. Account for additional pressure drop through the catalyst.

d. Install a DSI control system to address increased SO₂ to SO₃ conversion, and increased sulfuric acid mist and condensible particulate matter emissions.

e. Evaluate the need to retrofit a fabric filter baghouse to ensure continued compliance with the unit’s PM emission limit.

**Task 2: Control System Modifications**

Without redesigning the entire SCR control system and BOP equipment, and without altering the unit’s planned maintenance cycle, the only options available to SRP to achieve lower NOx...
emissions on CGS Unit 2 include the installation of a low-load temperature control system, adding additional catalyst to the existing SCR reactor box, and increasing the NH₃ injection rate to provide additional NOx removal. This approach would maintain the current 25,000 hour catalyst design life and allow SRP to incorporate catalyst changes into its existing 3-year planned maintenance cycle.

Increasing the catalyst volume will result in increased SO₂ to SO₃ conversion across the SCR. SO₃ can react with water to form sulfuric acid mist (H₂SO₄) or with unreacted NH₃ to form ammonium salts. Sulfuric acid mist and ammonium salts are classified as condensable particulates, and can increase total PM emissions from the unit. The facility’s existing Title V Operating Permit requires that SRP conduct stack testing after installation of the Unit 2 SCR to determine if H₂SO₄ emissions are consistently less than or equal to 0.006 lb/MMBtu. If stack test results demonstrate that Unit 2 H₂SO₄ emissions exceed 0.006 lb/MMBtu, SRP must prepare an H₂SO₄ minimization analysis that evaluates further options, including but not limited to reagent/sorbent injection, to reduce emissions to 0.005 lb/MMBtu or less, while maintaining PM emissions within 80% of unit’s 0.030 lb/MMBtu limit.

Installation of the additional catalyst and the resulting increase in SO₂ to SO₃ conversion makes it significantly more likely that H₂SO₄ emissions from CGS Unit 2 will exceed 0.006 lb/MMBtu. Assuming H₂SO₄ emissions exceed 0.006 lb/MMBtu, SRP would be required to install a DSI control system to mitigate H₂SO₄ emission increases. The DSI control system would inject sorbent after the unit’s hot side electrostatic precipitators and air heater to capture the acid gas.

To ensure continued compliance with the unit’s PM emission limit, particulates generated in the SCR and DSI control systems would have to be collected in the unit’s existing wet FGD control system. If particulate matter emissions exceed the applicable permit limits, SRP’s only option would be to install a fabric filter baghouse upstream of the unit’s wet FGD. Conceptual design layouts show that the installation of a fabric filter baghouse on CGS Unit 2 would be a complicated retrofit project and would require significant modifications to the existing unit.

The need for DSI and fabric filter baghouse controls could only be determined after the SCR is installed and initial operating tests are performed. A detailed demonstration plan would be
required to determine \( \text{H}_2\text{SO}_4 \) emissions, demonstrate the effectiveness of the DSI control system, and determine whether a fabric filter baghouse would be required for PM control.

**Task 2: Control System Modifications - Capital Costs**

Capital costs associated with redesigning the SCR to achieve more aggressive NOx control include the cost of installing the low-load temperature control system, increased capital costs associated with the initial catalyst fill, and capital costs associated with SO\(_3\) and PM emission controls. The total increase in capital costs will range from a minimum of $8,350,000 (including the additional catalyst, low-load temperature control system, and DSI control system, but no fabric filter baghouse) to as much as $117,850,000 (including a fabric filter baghouse). Capital costs include the following:

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Additional Catalyst</td>
<td>$350,000 to $1,600,000</td>
</tr>
<tr>
<td>Low-Load Temperature Control System</td>
<td>$2,000,000 to $3,000,000</td>
</tr>
<tr>
<td>SO(_3) Control System</td>
<td>$6,000,000 to $7,000,000</td>
</tr>
<tr>
<td>Structural Modifications</td>
<td>Not Required</td>
</tr>
<tr>
<td>Fabric Filter Baghouse &amp; ID Fans(^{(1)})</td>
<td>$85,000,000 to $106,250,000</td>
</tr>
</tbody>
</table>

\(^{(1)}\) The new ID fans recently installed by SRP as part of the new FGD on CGS Unit 2 are unlikely to be sufficient to overcome the additional pressure drop associated with a new fabric filter baghouse.

The wide range additional catalyst cost shown above depends on project timing. The lower cost ($350,000) is associated with adding approximately 10% more catalyst to the existing reactor box during initial installation. This can be achieved by installing longer catalyst elements into the SCR reactor box, and can be implemented only if this change can be specified prior to commencing catalyst fabrication. However, once catalyst fabrication starts, the only option would be to add a partial fourth catalyst layer in the space currently reserved for a fourth catalyst layer as part of the initial fill. This option increases the initial capital cost to approximately $1,600,000, including installation costs.

Similarly, a range of costs is shown for the low-load temperature control system, the SO\(_3\) mitigation system, and the fabric filter baghouse. Additional engineering and design would be required for all of these systems to better define the costs.
Task 2: Control System Modifications - Operating & Maintenance Costs

O&M costs associated with the design and operating modifications described above include an incremental increase in the catalyst replacement cost to account for the additional catalyst, an incremental increase in the ammonia consumption rate based on the additional NOx removed, increased parasitic energy consumption associated with the increased pressure drop across the catalyst bed, sorbent consumed in the SO$_3$ control system, increased parasitic energy consumption and bag/cage replacement costs associated with the fabric filter baghouse (if required).

Total increased annual O&M costs will range from a minimum of $1,461,000/yr (without the fabric filter baghouse) to approximately $3,881,000/yr (with the fabric filter baghouse). Annual O&M costs include the following:

<table>
<thead>
<tr>
<th>Incremental Cost Description</th>
<th>Cost Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incremental Catalyst Replacement Cost$^{(1)}</td>
<td>$193,000 to $343,000</td>
</tr>
<tr>
<td>Incremental Ammonia Cost$^{(2)}</td>
<td>$28,000</td>
</tr>
<tr>
<td>Incremental Pressure Drop Across SCR$^{(3)}</td>
<td>$40,000 to $110,000</td>
</tr>
<tr>
<td>DSI Control System Operating Costs$^{(4)}</td>
<td>$1,200,000</td>
</tr>
<tr>
<td>Fabric Filter Baghouse Operating Costs$^{(5)}</td>
<td>$2,200,000</td>
</tr>
</tbody>
</table>

$^{(1)}$ The annual catalyst replacement cost will be a function of the approach taken to increase the volume of catalyst. Incremental catalyst replacement costs are based on the increased catalyst volume and assuming 11 replacements over the initial 20-operating years of the control system.

$^{(2)}$ Incremental ammonia costs reflect the increased ammonia consumption associated with additional NOx reduction, and is calculated based on 0.01 lb/MMBtu NOx removal @ $400/ton NH$_3$.

$^{(3)}$ Operating costs associated with increased pressure drop across the SCR depends on which catalyst option is implemented, and will range from 0.3” to approximately 0.8” w.c. across the catalyst.

$^{(4)}$ DSI control system operating costs include sorbent costs for acid gas control.

$^{(5)}$ Fabric Filter Baghouse operating costs include routine bag & cage replacement costs, auxiliary power costs, and fixed maintenance material and labor costs.

Schedule Impacts

The CGS Unit 2 SCR control system has been engineered and designed, and contracts have been awarded for control system fabrication. The current SCR control system design does not include a low-load temperature control system, an SO$_3$ mitigation system, or a fabric filter baghouse. Implementation of any of these systems would require additional engineering, design, procurement, and fabrication phases that would be difficult to complete in advance of the planned installation date.
for the Unit 2 SCR, with is scheduled to be completed during SRP’s next planned outage in Spring 2014. Typical project durations to bring these major pieces of equipment on-line would be:

- Low-Load Temperature Control System: 14 to 24 months
- SO$_3$ Mitigation System (DSI): 18 to 30 months
- Fabric Filter Baghouse & ID Fans: 36 to 42 months

A more detailed analysis of these control systems would need to be evaluated to determine their feasibility and to define an achievable implementation schedule.

In addition, there are current significant scheduling constraints that could affect costs associated with re-designing the Unit 2 SCR. As noted above, once fabrication of the SCR catalyst system begins, design changes needed to increase the catalyst volume become much more expensive. At the time of this report, it is our understanding that the catalyst supplier has been issued a purchase order and is free to begin fabrication at any time.
Salt River Project  
Coronado Generating Station  
Coronado Generating Station Unit 2 SCR Review  
August 24, 2012  

ATTACHMENTS

<table>
<thead>
<tr>
<th>Attachment</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1a</td>
<td>Unit 1 Load Profile (1/11 – 7/12)</td>
</tr>
<tr>
<td>1b</td>
<td>Unit 2 Load Profile (1/11 – 6/12)</td>
</tr>
<tr>
<td>2</td>
<td>Unit 2 Load Cycling</td>
</tr>
<tr>
<td>3</td>
<td>Unit 2 High-Load Cycling Model (60% - 100% Gross Load Cycling)</td>
</tr>
<tr>
<td>4</td>
<td>Unit 2 Low-Load Cycling Model (40% to 100% Gross Load Cycling)</td>
</tr>
<tr>
<td>5a</td>
<td>30-Day Rolling Average Model (Dates from Unit 1 Load Profile)</td>
</tr>
<tr>
<td>5b</td>
<td>30-Day Rolling Average Model (Dates from Unit 2 Load Profile)</td>
</tr>
<tr>
<td>6</td>
<td>Unit 2 Startup Data from 5/1/3/2012</td>
</tr>
<tr>
<td>7</td>
<td>Unit 2 Shutdown Data from 5/3 to 5/5/2012</td>
</tr>
</tbody>
</table>
Attachment 1a - Unit 1 Load Profile (1/11-7/12)
Attachment 4 - Unit 2 Low Load Cycling Model
(40-100% Gross Load Cycling)
Attachment 5b - 30-Day Rolling Average Model
(Dates from Unit 2 Load Profile)

- SCR, No Low Load Temperature Control System
- SCR, Low Load Temperature Control System
Supplemental Petition of Salt River Project Agricultural Improvement and Power District for Partial Reconsideration and Stay of EPA’s Final Rule: “Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans”

Attachment B
DECLARATION OF THOMAS COOPER
IN SUPPORT OF THE SUPPLEMENTAL PETITION OF
SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER
DISTRICT FOR PARTIAL RECONSIDERATION AND STAY OF
EPA'S FINAL RULE: "APPROVAL, DISAPPROVAL AND PROMULGATION
OF AIR QUALITY IMPLEMENTATION PLANS; ARIZONA;
REGIONAL HAZE STATE AND FEDERAL IMPLEMENTATION PLANS"

I, Thomas Cooper, having first been duly sworn upon my oath, declare and state as follows:

1. My name is Thomas Cooper, and I am the Director of Resource Planning & Development for Salt River Project Agricultural Improvement and Power District ("SRP"). My business address is ISB669, 1600 N. Priest Drive, Tempe, Arizona 85281. I am competent to testify concerning the matters in this declaration. I received a Bachelor of Science degree in Economics from Arizona State University in 2001 and a Master of Business Administration degree from Arizona State University’s W. P. Carey School of Business in 2006. I have more than 14 years of experience in the electric utility industry. I worked for New West Energy, SRP’s affiliate that competed in the deregulated market, starting in 2000, and I moved to SRP in 2001. Since joining SRP, I have held a variety of positions in corporate finance, retail pricing, emissions trading, merchant transmission, natural gas trading and scheduling, operations, resource planning, asset acquisition, and contract development.

2. In my current position with SRP, I am responsible for the development of SRP’s Integrated Resource Plan ("IRP"). A key consideration in the development of the SRP IRP is the evaluation of SRP’s generating resources and their availability to serve the needs of SRP’s customers now and in the future. This includes evaluating the availability of the Coronado Generating Station ("Coronado"), a coal-fired electric generating facility owned and operated by SRP, as it is affected by environmental regulations and other impacts on operation. In addition, I
am responsible for conducting economic analyses of resource alternatives and for analyzing the economic and resource adequacy implications of constraints on the operation of SRP resources, including environmental regulations such as the U.S. Environmental Protection Agency’s ("EPA" or "Agency") proposed rule, titled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units." 79 Fed. Reg. 34,830 (June 18, 2014) ("111(d) Proposal").

3. This declaration is submitted in support of SRP’s supplemental petition for partial reconsideration and stay of the final rule issued by EPA, titled "Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Final Rule," 77 Fed. Reg. 72512 (December 5, 2012) ("Final Rule"), and for a stay of the effective date of the federal implementation plan ("FIP") promulgated as part of the Final Rule. SRP is challenging certain elements of EPA’s best available retrofit technology ("BART") determination affecting Coronado and seeks a stay of the effective date of the FIP for Coronado and a tolling of its compliance period.

4. SRP’s analysis shows that implementation of the 111(d) Proposal, if made final by EPA, almost certainly would result in the closure of Coronado. This is consistent with EPA’s own analysis. In the 111(d) Proposal, EPA determined that the best system of emissions reduction ("BSER") for greenhouse gas emissions from existing sources consists of four building blocks. After applying these building blocks to the State of Arizona, EPA established a final goal for Arizona in 2030 of 702 pounds of carbon dioxide per megawatt hour ("lb CO₂/MWh"), which represents a 52 percent reduction from 2012 levels. EPA also proposes an interim emission rate goal of 735 lb CO₂/MWh applicable on an average basis over the period of 2020 to 2029.
5. EPA calculated Arizona’s 2012 baseline fossil-fuel generation emission rate at 1,551 lb CO₂/MWh and then adjusted this baseline to include certain zero-carbon/renewable resources in place in Arizona in the baseline year. After that adjustment, EPA calculated Arizona’s baseline emission rate at 1,453 lb CO₂/MWh. As outlined in Table 1, EPA then applied each of the four building blocks to the adjusted baseline emissions rate to establish the emission rate goals for Arizona. A summary of how EPA applied the building blocks to the 2012 fossil-fuel generation emission rate to calculate Arizona’s 2030 emission rate goal is provided in the table below:

Table 1: EPA’s Determination of Arizona’s 2030 Emission Rate Goal

| Building Block 1 | 1,453 → 1,394 lb CO₂/MWh | Improve heat rate for coal-fired units by 6%. |
| Building Block 2 | 1,394 → 843 lb CO₂/MWh | Re-dispatch coal and oil/gas steam units by increasing existing natural gas combined cycle generation up to 70% capacity (53% for Arizona). |
| Building Block 3 | 843 → 814 lb CO₂/MWh | Avoid retirement of “at risk” nuclear capacity and add new nuclear capacity. Increase renewable energy capacity to reflect regional averaging of renewable portfolio standards. |
| Building Block 4 | 814 → 702 lb CO₂/MWh | Increase demand-side energy efficiency improvements to achieve 1.5% annual savings. |

6. The vast majority of the emission reductions EPA assigns to Arizona, as shown in Table 1 above, can be directly attributed to the application of Building Block 2, which replaces existing in-state coal generation with existing in-state natural gas combined cycle (“NGCC”) generation. See also “Building Block #2 Impacts on the Emission Rate Goals for Arizona under EPA’s Clean Power Plan Proposal” (Attachment B-1). EPA’s proposed rule sets an interim goal for Arizona based on the assumption that Building Block 2 can be implemented by the first year of the compliance timeframe, i.e., 2020. EPA appears to assume this is reasonable because Building Block 2 is based on redispetch from coal- and natural gas-fired generation to existing
NGCC generation, a measure that is purportedly more readily achievable than, for instance, the construction of new renewable generation. This is confirmed in the 111(d) Proposal, where EPA states that “building block 2, which represents shifting of generation from steam fossil EGUs [electric generating units] to existing NGCCs, is a viable method for providing CO₂ emission reductions at existing EGUs by the 2020 compliance start date.” 79 Fed. Reg. at 34,905-06. The net effect of this early resource shifting is that the 2020-2029 interim goal for Arizona is only 33 lb CO₂/MWh higher than the final goal. Having an interim goal so close to the final goal creates a situation in which, mathematically and pragmatically, Arizona has no choice but to rely on EPA’s Building Block 2 to achieve required progress toward the 2030 goal. In this case, almost all of the required reductions must occur in 2020.

7. Based on SRP’s analysis, the dramatic decrease in emissions that would be required by the 111(d) Proposal would likely require the retirement by the year 2020 of all coal-fired generation that is subject to the State of Arizona’s regulatory jurisdiction. As explained further below, even if some Arizona coal-fired generation could be maintained by relying more extensively on other building blocks, the Coronado units would not remain operating in any of those circumstances. If all of the coal-fired generation in Arizona is shut down by 2020, the state’s CO₂ intensity measure drops from 1,453 lb CO₂/MWh in 2012 to 843 lb CO₂/MWh in 2020. This level of reduction would be required in 2020 for Arizona to be able to comply with the interim target of 735 lb CO₂/MWh, assuming the same expansion of renewables and energy efficiency programs contemplated in EPA’s goal-setting analysis. This finding is consistent with EPA’s own goal-setting computations for the 111(d) Proposal. See Technical Support Document: Goal Computation, Appendix 1, Docket ID No. EPA-HQ-OAR-2013-0602 (indicating that Arizona is left with zero coal-fired generation after re-dispatch to NGCC units). EPA calculated that the capacity factor for the NGCC fleet would need to be 53% for Arizona to provide the same total generation as it did in 2012. At this level, NGCC generation entirely displaces coal-fired and oil- and gas-fired steam generation. This re-dispatch of generation, as assumed by EPA, is summarized in Table 2:
Table 2: Generation Adjustments Resulting from Re-Dispatch

<table>
<thead>
<tr>
<th>Generation Type</th>
<th>Total Generation in 2012 (MMWh)</th>
<th>Total Generation EPA Assumed in Developing State Emission Rate Goal (MMWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Generation</td>
<td>24.3</td>
<td>0</td>
</tr>
<tr>
<td>Natural Gas Combined Cycle Generation</td>
<td>26.8</td>
<td>52.1</td>
</tr>
<tr>
<td>OG Steam Generation</td>
<td>1.0</td>
<td>0</td>
</tr>
<tr>
<td>“Other” Generation¹</td>
<td>0.02</td>
<td>0.02</td>
</tr>
</tbody>
</table>

¹ “Other” generation includes 17,227,768 pounds of CO₂ from Yuma Cogeneration Associates

Based on EPA’s assumed emission rate for the NGCC generation (i.e., 900 lb CO₂/MWh), applying Building Block 2 to the emission rate established under Building Block 1 reduces Arizona’s emission rate goal from 1,394 lb CO₂/MWh to 843 lb CO₂/MWh. That level of immediate reduction can be met only by shutting down all of the Arizona coal-fired generation.

8. In an attempt to evaluate possible alternatives, SRP considered the effect of increasing the use of renewable energy and energy efficiency programs (as contemplated in Building Blocks 3 and 4) as a means to offset coal-fired plant emissions under the 111(d) Proposal. Our analysis indicates that by nearly doubling the use of renewable energy resources and energy efficiency programs, the state might be able to preserve about 400 MW of coal-fired capacity operating in an economically reasonable fashion. However, in doing so, Arizona would end up with a final intensity measure significantly below the 111(d) Proposal’s 2030 target for Arizona. SRP’s calculations indicate that Arizona would be at 647 lb CO₂/MWh in 2030, which is 55 lb CO₂/MWh below the final target for Arizona of 702 lb CO₂/MWh. That 400 MW is only 11 percent of the existing coal-fired capacity subject to the state’s jurisdiction, as defined by the 111(d) Proposal.

9. If increased use of renewable energy were chosen as the means to save these 400 MW of coal-fired generation, it would require the equivalent of approximately 3,600 MW of
single-axis tracking solar photovoltaic generation, assuming a gradual phase-in between 2020 and 2030. Solar generation would be the most likely renewable resource to be selected due to its favorable economic profile compared to other in-state renewable energy alternatives and the uncertainty surrounding the ability to count out-of-state renewable generation towards compliance with a section 111(d) rule. And, while such an expansion of solar generation may not be impossible, it would constitute a very significant undertaking within the timeframe that would be necessary, due both to the construction of the generating facilities and to the construction of the associated infrastructure that likely would be required.

10. More importantly, Coronado Unit 1 would be quite far down the list of Arizona coal-fired capacity likely to be preserved, given its vintage and the current requirement in EPA’s BART FIP to install selective catalytic reduction (“SCR”) at Coronado Unit 1 for that unit to remain operational. If Arizona were able to keep any coal-fired units operating, it is most likely that those units would be Springerville Generating Station (“Springerville”) Units 3 and 4. Those two units are the newest coal-fired units in the state, having come on-line less than 10 years ago, and they also are two of the best-controlled coal-fired units, in terms of air emissions, in the state. Both Springerville Units 3 and 4 have installed the best available control technology, including low NOx burners and SCR for nitrogen oxide (“NOx”) emission control, dry flue gas desulfurization (“DFGD”) systems for sulfur dioxide (“SO2”) control, and pulse jet baghouses for particulate-matter control, with continuous 24-hour emissions monitoring. As new, highly-controlled coal-fired units, Springerville Units 3 and 4 would be the mostly likely to be preserved for two primary reasons. First, the remaining book value of these units is high relative to that of other units. Second, the risk of incurring significant expense for installing additional pollution control equipment is much lower at these Springerville units than at other Arizona units, which are less highly-controlled. Together, Springerville Units 3 and 4 represent 834 MW of coal-fired generating capacity, and in order to preserve even these two units, an even further and more onerous expansion of variable renewable generation and energy efficiency programs would be required in Arizona. For this reason, SRP’s evaluation leads SRP to conclude that continued
operation of Coronado is an unreasonable expectation if EPA were to finalize the 111(d) Proposal.

11. Taking action to comply with the BART FIP for Coronado is unreasonable in light of the outcomes that would result from finalization of the 111(d) Proposal. Indeed, compliance with the 111(d) Proposal would create a situation that differs fundamentally from that reflected in the information and assumptions that EPA used when it published the BART FIP for Coronado in 2012, and such a BART determination would not be made today. See Declaration of James M. Pratt ¶ 12.

Executed on November 11, 2014

Thomas Cooper
Attachment B-1
Executive Summary

On June 2, 2014, the U.S. Environmental Protection Agency (EPA) issued its proposed Clean Power Plan, which included interim and final carbon dioxide (CO₂) emission rate goals for each state. EPA developed these goals using a prescribed formula in which they applied four “building blocks” that each reflect measures a state can take to reduce CO₂ emissions. EPA states these four building blocks comprise EPA’s determination of the “Best System of Emissions Reduction” (BSER) for existing power plants under the provisions of Section 111(d) of the Clean Air Act.

In Arizona, EPA’s application of Building Block #2 (BB2), which re-dispatches coal and oil/gas (OG) steam generation to natural gas combined cycle (NGCC) generation, accounts for more than 80% of the total reductions associated with the proposed rule. The fact that EPA established the interim goal assuming that BB2 is fully implemented by 2020 means these reductions must take place by 2020 in order to meet the interim CO₂ emission rate goal, which is simply not possible.

Furthermore, the level of reduction assumed by the application of BB2 cannot be made up with Building Blocks 3 and 4. If the state were to increase implementation of renewable energy and energy efficiency measures in an attempt to retain a portion of the existing coal generation, it would be impossible to meet the interim target proposed by EPA.

In fully considering the assumptions and application of BB2, there are three primary issues that need to be addressed in the development of a final rule:

- **Existing NGCC generation cannot replace coal capacity over peak demand hours.**
  - EPA bases the re-dispatch potential on the average annual capacity factor, rather than accounting for peak capacity needs. During peak periods, all existing NGCC resources within Arizona are in use, leaving no available existing NGCC generation capacity to replace the existing coal and OG steam generation during these periods. Moreover, a neighboring state could purchase the output of the NGCC units, thereby reducing capacity available for Arizona redispersal while increasing the state’s carbon emissions.

  Arizona is home to more than 5,000 megawatts of merchant gas generation. This generation currently helps to meet peak summer demand not only in Arizona, but in neighboring states as well. The BB2 formula does not address the realities of the wholesale power market.
and inappropriately assumes that all of this merchant gas generation would only be sold to in-state entities over peak demand hours.

- To replace lost coal and OG steam generation, Arizona would need to construct new NGCC plants to ensure adequate system reliability during peak demand periods, which is not possible within the tight compliance timeline proposed by EPA. Partial shutdown of coal units is not an option for meeting Arizona goals as the state’s coal plants cannot be run for a few hours a day to meet peak load, and running them as baseload units in only the summer months to meet peak demand does not allow the state to meet its interim goal.

- There is also strong evidence from recent modeling work done in the region that retirement of all existing Arizona coal generation by 2020 would have significant adverse affects on the reliability and load serving capability of the state’s transmission system. Arizona is further investigating this issue and plans to address it in future comments to EPA.

- **Application of an inappropriate emission factor for NGCC generation.** In calculating the emission rate targets for Arizona, EPA assumed that NGCC units would operate in future years at a CO₂ emission rate of 900 pounds per Megawatt-hour (lb/MWh). This value is the combined average annual emissions rate for the NGCC units in Arizona during 2012. However, this emission factor is not consistent with EPA’s analysis regarding emission rate capabilities for new, highly efficient units under Section 111(b).\(^1\)

- **Failure to properly account for remaining useful life for coal-fired units.** EPA contends that states were provided with flexibility to deploy the identified building blocks to address key issues such as remaining useful life. However, if Arizona increases implementation of Building Blocks 3 and 4, Arizona is still not able to retain coal generation and meet the proposed EPA targets. This is a clear demonstration that the state does not have the flexibility assumed by EPA to factor remaining useful life into the state’s compliance plan. In the absence of state flexibility, EPA should incorporate remaining useful life into the goal-setting analysis for Arizona to ensure the state is able to retain important baseload generation resources.

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\(^1\) In EPA’s January 2014 proposal, CO₂ emission rates for new units were proposed at 1,000 lb/MWh for NGCC units with a capacity greater than 850 MMBtu/hour and 1,100 lb/MWh for NGCC units with a capacity of 850 MMBtu/hour or less. Refer to 79 Fed Reg. at 1,433.
Given that BB2 accounts for more than 80% of the emission reductions required for Arizona, these issues must be addressed to ensure Arizona is not disproportionately and unfairly impacted by the proposed rule.

1.0 Introduction

On June 2, 2014, EPA issued its proposed Clean Power Plan, which includes mandatory CO₂ emission rate goals for each state. The proposed rule does not require uniform reductions across the country; rather each state has different emission rate goals. Some state goals, such as those for Arizona, establish greater emissions reduction burdens than others.

EPA developed these goals using a prescribed formula in which they applied four “building blocks” that each reflect measures a state can take to reduce CO₂ emissions. The building blocks EPA adopted include:

- **Building Block #1**: Heat rate improvements at coal-fired units;
- **Building Block #2**: Re-dispatch of coal and OG steam generation to NGCC generation;
- **Building Block #3**: Retention of at-risk nuclear generation and addition of new renewable generation; and
- **Building Block #4**: Implementation of end-use efficiency measures.

EPA states these four building blocks comprise EPA’s determination of BSER for existing power plants under the provisions of Section 111(d) of the Clean Air Act.

EPA applied the building blocks to calculate two emission rate goals for each state: 1) an “interim” 10-year average goal that must be met from 2020 through 2029; and 2) a final goal in 2030. For Arizona, the proposed interim emission rate goal is 735 lb CO₂/MWh and the 2030 emission rate goal is 702 lb CO₂/MWh.

Of the four building blocks, the application of BB2 results in the most significant projected reduction in CO₂ emissions for Arizona. Specifically, the application of BB2, accounts for more than 80% of the total reductions associated with the proposed rule for Arizona.

EPA’s reliance on BB2 to achieve dramatic emissions reductions in Arizona by 2020 has significant implications for reliability and economics. In establishing the emissions target for Arizona, EPA assumed that all coal and OG steam generation in the state

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2 This reduction is calculated considering the change in emissions from the 2012 baseline emissions rate to the emissions rate after BB2 is applied. This value includes the assumed reductions from Building Block 1 since there is no real reduction from Building Block 1 with all coal eliminated under BB2.
would be replaced with NGCC generation by 2020. Figure 1 demonstrates the dramatic impact that BB2 has on the compliance glide path for Arizona.

Figure 1. Impact of EPA’s Interim and Final Goals in Arizona

This impact is further amplified when considering the schedule that has been established for approval of state plans. At best, the state will have 2 ½ years to implement its compliance plan for the Clean Power Plan. If the state requests an extension for plan submittal, it is possible that Arizona will have only 6 months to implement its plan. Given that EPA assumes the state must focus on BB2 to achieve compliance, Arizona could have as little as 6 months to shift the entirety of coal generation to NGCC generation to supply electric power to the state’s residents and businesses. EPA simply does not provide the state enough time to complete such a dramatic shift in Arizona’s energy supply.

3 Within the Presidential Memorandum regarding Power Sector Carbon Pollution Standards issued on June 25, 2013, the President outlines expected targets for completion of major milestones under the rule including issuing final standards no later than June 1, 2015 and state plan submittal no later than June 30, 2016. Within the rule proposal, EPA indicates they will take one year to review those plans so that states have a final determination by June 2017; hence, 2 ½ years to implement in accordance with the 2020-2029 interim goal. This timeframe does not contemplate the potential for an additional 1-2 year extension to submit compliance plans if requested by the state per the extension options provided in the proposed rule. While the extension gives more time to complete the plan, it does not delay the rule’s compliance obligations, which begin in 2020.
Unfortunately, EPA’s calculation methodology for BB2 is based on a number of underlying assumptions that are inaccurate for Arizona, which are outlined in the following sections.

2.0 EPA’s Calculation Methodology for BB2

In its application of BB2, EPA re-dispatches a state’s existing NGCC generation to replace coal-fired and OG steam generation.

In applying BB2 to Arizona, EPA first calculated Arizona’s annual generation rate from coal and OG steam plants using data from 2012. Next, EPA determined the amount of existing NGCC capacity in use in the state in 2012 (27%), and determined the total annual generation that the NGCC plants could produce at a 70% capacity factor. If the annual generation at 70% capacity factor was sufficient to equal or exceed the generation from coal and OG steam plants, EPA’s calculation assumed that NGCC generation would replace coal and OG steam generation beginning in 2020. The emission rate that EPA applied to the NGCC generation used in this calculation was the combined average annual emission rate from those resources in 2012 (900 lb CO₂/MWh).

For Arizona, EPA’s calculation results in the total displacement of coal and OG steam generation by increasing the annual average capacity factor of existing NGCC plants from 27% to 53% by 2020, as shown in Figure 2. When this building block is applied to Arizona’s 2012 adjusted baseline emissions rate of 1,453 lb CO₂/MWh, it drops the state emission rate to 843 lb CO₂/MWh.⁴

Figure 2: Snapshot of EPA’s Re-Dispatching Approach

<table>
<thead>
<tr>
<th>State</th>
<th>Hist Coal Gen. (MWh)</th>
<th>Hist NGCC Gen. (MWh)</th>
<th>Historic OG steam Gen. (MWh)</th>
<th>NGCC Capacity (MWh)</th>
<th>Redispatched Coal Gen. (MWh)</th>
<th>Redispatched OG steam Gen. (MWh)</th>
<th>Redispatched NGCC Gen. (MWh)</th>
<th>2012 NGCC Capacity Factor</th>
<th>Post Redispatch Assumed NGCC Capacity Factor for Existing Fleet</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>46,045,176</td>
<td>53,492,096</td>
<td>10,339</td>
<td>36,001,107</td>
<td>0</td>
<td>61,536,165</td>
<td>59%</td>
<td>70%</td>
<td></td>
</tr>
<tr>
<td>Alaska</td>
<td>215,407</td>
<td>2,204,942</td>
<td>0</td>
<td>589</td>
<td>0</td>
<td>2,420,349</td>
<td>43%</td>
<td>47%</td>
<td></td>
</tr>
<tr>
<td>Arizona</td>
<td>24,335,930</td>
<td>26,782,325</td>
<td>1,033,871</td>
<td>11,202</td>
<td>0</td>
<td>52,152,127</td>
<td>27%</td>
<td>53%</td>
<td></td>
</tr>
</tbody>
</table>

It is important to note that the level of reduction assumed by the application of BB2 cannot be made up with Building Blocks 3 and 4. The level of additional renewable generation and energy efficiency measures required to avoid significant coal plant shutdowns in 2020 is not achievable.

⁴ Although EPA assumes Building Block #1 will contribute reductions to achievement of emissions rate goals, if all coal units are displaced by natural gas generation by 2020, there is no coal generation remaining and no emissions reductions would be achieved through this building block.
3.0 Issues with EPA Assumptions Under BB2 Related to NGCC Capacity

EPA’s application of BB2 to establish Arizona’s emissions rate goals suggests the agency has a fundamental misunderstanding of how utilities plan and operate to meet electricity demand. There are many factors that must be considered when assessing a unit’s capacity factor.

Utilities must ensure that sufficient resources are available to meet peak demand, not just annual average demand. Peak demand occurs when consumer demand for electricity is at its highest level, which for Arizona corresponds with the high temperatures in the summer months. During these months, temperatures regularly exceed 110 °F. EPA’s calculation does not account for the fact that demand for electricity in Arizona is much higher in the summer than in the winter. NGCC generation in the state is used heavily in the summer months and much less in the winter months when demand is very low. An NGCC resource could easily run at a 90% capacity factor during the peak summer hours, but have an annual capacity factor around 30%.

For example, Figure 3 illustrates peak demand for electricity (“retail firm load”) from SRP’s system in 2012. Peak electricity demand can be more than twice as high as base demand in the off-peak months. Furthermore, while forecasted values trend well with actual values, utilities still cannot predict exactly when the highest peak will occur and how high that peak will be.

Figure 3: 2012 SRP Retail Firm Load Profile
In 2012, SRP reached its highest peak hourly load value of 6,663 megawatts on August 8. Figure 4 shows a breakdown of the generating resources that were operating during that peak hour to meet customer demand. During this hour, all available generation resources, including coal and OG steam plants, were being utilized at full capacity to meet that peak demand. Even with all SRP system resources being utilized at full capacity, SRP was still forced to purchase electricity on the open market to meet peak demand and Federally-required reserve requirements.

Figure 4: Resources Needed by SRP to Meet Peak Demand on August 8, 2012

* All available generation resources were operating at full capacity, except for a small portion held to meet reserve requirements.

It is clear that without coal and OG steam resources, SRP would not have been able to meet the peak electricity demand without purchasing a significant amount of electricity from the short-term market in addition to what is already being purchased, which is a costly and risky endeavor, assuming that such power is even available. Arizona is not the only state in the Western U.S. that experiences these high peaks in the summer. As such, other utilities are likely to be competing for that same power, at the same time, on the short-term market.

Electricity market prices are a strong and reliable indicator of available capacity. If the market price greatly exceeds the variable cost of NGCC generation that is evidence that all NGCC generation has been deployed and no available surplus remains. This is not an unusual occurrence in the summer months and is driven by high temperatures, transmission line outages, unplanned generation outages, or any combination of these events.
While Figure 4 shows a single peak hour, Figure 5 provides an annual look at how SRP’s generation resources would fall short if SRP were required to replace all existing coal and OG steam generation with NGCC generation. For illustrative purposes, SRP assumed a 100% NGCC capacity factor on an hourly basis, which equates to 84% on an annual average basis. This level of dispatch exceeds EPA’s assumption of 70% on an annual average basis.

**Figure 5: Potential Re-Dispatch of SRP Generation Resources**

As Figure 5 demonstrates, even with an extremely aggressive NGCC re-dispatch assumption, SRP would still have significant shortages in generation for several months in the summer. This lack of generation would be further aggravated if out-of-state coal resources also are eliminated due to compliance with the Clean Power Plan.

It is important to note that there are a number of merchant NGCC plants in Arizona that EPA included in the total capacity available for re-dispatch. Merchant plants differ from traditional rate-based power plants in (1) how they are financed and (2) where they sell the electricity they generate. A merchant plant is funded by investors and sells electricity in the competitive wholesale power market. Since a merchant plant is not required to serve any specific retail consumers, consumers are not obligated to pay for the construction, operation, or maintenance of the plant.
The nominal capacity available from merchant generators in Arizona is more than 5,000 megawatts, accounting for 53% of the NGCC capacity in the state. Arizona’s load serving entities purchase energy from merchant generators through long-term firm purchase agreements or through shorter term transactions. Aside from making such purchases, Arizona’s utilities have no control over the dispatch of merchant generation.

Setting aside constraints on merchant use posed by their business structure, SRP still investigated the availability of merchant NGCC plants within Arizona using data obtained from EPA’s Clean Air Markets Database, which was used to determine hourly generation loads. Figure 6 shows the level at which merchant NGCC plants were dispatched over the peak hour on each day in the summer of 2012. All of the merchant plants in Arizona often operate at full or nearly full output during peak months to meet demand not only in Arizona, but in neighboring states as well. As such, utilities cannot rely on any significant amount of merchant generation in long-term planning to meet system demand requirements during peak summer demand periods. It should further be recognized regional peak demands have been increasing and are projected to continue to increase. Therefore, even if there was currently a small surplus of regional capacity, it will quickly be absorbed by load growth and already announced coal and nuclear plant retirements, such as Units 1, 2 and 3 at the Four Corners Power Plant and all units at the San Onofre Nuclear Generating Station.

Figure 6: Merchant NGCC Plant Utilization in Arizona
SRP’s analysis indicates that Arizona cannot solely rely on existing NGCC capacity to meet peak demand because these facilities are already being fully utilized in certain hours of the year to serve regional loads. Coal and OG steam plants provide vital capacity during summer months, and that capacity must remain available to ensure system reliability during periods of peak demand. Coal plants cannot be run for a few hours a day to meet peak load; on the other hand, running them as baseload units in only the summer months to meet peak demand does not allow the state to meet its interim goal.

If Arizona’s emissions rate goals can only be met through retirement of all coal and OG steam plants, additional NGCC resources will be needed to cover state electricity demand. EPA did not presume that new resources would be needed to replace coal and OG steam in setting state emission rate goals. For states in such situations, EPA must provide adequate time to site, plan, design, permit, and construct new generation resources and the infrastructure that supports these resources (e.g., new electric and gas transmission).

There are several factors that complicate a utility’s ability to construct new generation resources to meet the requirements associated with this rule. One of the biggest issues is the lengthy timelines association with siting and permitting of new energy infrastructure.

The Western U.S. is unique in the amount of land owned by the military, federal government, state governments, and tribal nations. In Arizona, approximately 41% of land is owned by the federal government, almost 13% by the state, and about 27% belongs to tribal nations.⁵ Siting and permitting of transmission lines on federal land, for example, can take 10 years or more. In many cases, obtaining the permits necessary to construct a transmission line can take longer than constructing the line itself.

Another issue is added regulatory complexities associated with locating a facility within a nonattainment area. Maricopa County, which serves as the largest load pocket within Arizona, currently does not meet the EPA’s National Ambient Air Quality Standards for ozone or particulate matter. The ozone standards are expected to be lowered by EPA in the near future. As EPA is aware, to construct a source in a nonattainment area, the project developer would need to obtain emissions offsets, which are not readily available. Projects are often delayed to allow for development of needed offsets through other air quality control projects.

There is also strong evidence from recent modeling work done in the region that retirement of all existing Arizona coal generation by 2020 would adversely affect the reliability and load serving capability of the state’s transmission system. Arizona is further investigating this issue and plans to address it in future comments to EPA.

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EPA’s Clean Power Plan Proposal
BB2 Impacts on the Emission Rate Goals for Arizona 10
4.0 Issues with EPA Assumptions Under BB2 Related to NGCC Emission Factors

In calculating the emission rate targets for Arizona, EPA assumed that NGCC units would operate in future years at a CO$_2$ emission rate of 900 lb/MWh. This value is the combined average annual emissions rate of all NGCC units in Arizona during 2012.

However, the emissions rate applied by EPA to existing units is at odds with EPA’s proposed rule establishing standards of performance for CO$_2$ emissions for new NGCC units. Specifically, in EPA’s January 2014 proposal, CO$_2$ emission rates for new units were proposed at 1,000 lb/MWh for NGCC units with a capacity greater than 850 MMBtu/hour and 1,100 lb/MWh for NGCC units with a capacity of 850 MMBtu/hour or less.\(^6\) EPA asserts that these emission rates can be met over the lifetime of a modern, high efficiency NGCC unit and are representative of the emissions rates of the best performing NGCC units in the country.

Even at these higher limits, EPA still acknowledges in the preamble of the proposed rule that nearly 10% of units today could not achieve the standards they have proposed for new units.

“…because over 90 percent of small and large existing NGCC facilities are currently operating below the emissions rates of 1,100 lb CO$_2$/MWh and 1,000 lb CO$_2$/MWh, respectively, these rates are considered BSER for new NGCC facilities in those respective subcategories.”

In calculating state goals under 111(d), EPA has assigned a more stringent CO$_2$ emission rate to existing NGCC units than the agency is proposing to assign to new, higher efficiency NGCC units. The analysis EPA conducted under its 111(b) proposal should hold true under the current 111(d) proposal since EPA evaluated all existing NGCC generation before setting the emissions rate limit for new units.

5.0 Issues with EPA Assumptions Under BB2 Related to Remaining Useful Life

EPA does not adequately address “remaining useful life” in its BSER analysis. In the preamble of the proposed rule, EPA discusses how states can address remaining useful life:

“Importantly, the proposed BSER, expressed as a numeric goal for each state, provides states with the flexibility to determine how to achieve the reductions (i.e., greater reductions from one building block and less from another) and to adjust the timing in which reductions are achieved, in order to address key issues

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\(^6\) 79 Fed Reg. at 1,433.

\(^7\) See Id. at 1,487.
such as cost to consumers, electricity system reliability and the remaining useful life of existing generation assets.\textsuperscript{8}

EPA contends that states were provided with flexibility to determine how to achieve reductions from other building blocks to address key issues such as remaining useful life. However, if Arizona increases implementation of Building Blocks 3 and 4, Arizona is still not able to retain coal generation and meet the proposed EPA targets. This is a clear demonstration that the state does not have the flexibility assumed by EPA to factor remaining useful life into the state’s compliance plan. In the absence of state flexibility, EPA should incorporate remaining useful life into the goal-setting analysis for Arizona to ensure the state is able to retain important baseload generation resources.

For example, SRP owns Unit 4 at the Springerville Generating Station, which commenced operation in December 2009. The bond financing was approximately 30 years with final bond maturity occurring in 2038. SRP also recently completed air pollution control equipment upgrades on Units 1 and 2 at the Coronado Generating Station, which cost approximately $500 million. The bond financing for this project was likewise 30 years with final bond maturity occurring in 2041.\textsuperscript{9}

Investments in these units were substantial and are being recovered in the rates of the consumers they serve. Forcing accelerated depreciation of these assets as envisioned by EPA will also accelerate rate recovery, placing an unreasonable burden on electric consumers, who must now cover the cost of prematurely retiring the units and the new NGCC units needed to replace them.

6.0 Conclusion

In Arizona, EPA’s full application of BB2 accounts for more than 80% of the total reductions associated with the proposed rule. The fact that EPA established the interim goal assuming that BB2 is fully implemented by 2020 means these reductions must take place by 2020 in order to meet that interim target, which is simply not possible.

Furthermore, the level of reduction assumed by the application of BB2 cannot be made up with Building Blocks 3 and 4. Even if the state were to increase implementation of renewable energy and energy efficiency measures in an attempt to retain a portion of the existing coal generation, it would be impossible to meet the interim target proposed by the EPA.

In fully considering the assumptions and application of BB2, there are three primary issues that need to be addressed in the development of a final rule:

\textsuperscript{8} See Id. at 34,836.

\textsuperscript{9} In fact, EPA acknowledged that Units 1 and 2 had a remaining useful life of 20 years in its regional haze determination.
• Meeting the interim goal would implicitly require the retirement of all or nearly all coal generation in the state. Existing NGCC generation cannot replace coal capacity over peak demand hours for a variety of reasons including lack of NGCC capacity during peak periods and merchant generation complexities, as well as an inability to replace critical coal capacity within the short timeframe provided.

• The NGCC emission factor EPA uses in its analysis under Section 111(d) should be consistent with its analysis of emission rate capabilities for new, highly efficient units under Section 111(b).

• EPA should incorporate remaining useful life into the goal-setting analysis to ensure states do have some level of flexibility in achieving those goals.

Given that BB2 accounts for more than 80% of the emission reductions required for Arizona, these issues must be addressed to ensure Arizona is not disproportionately and unfairly impacted by the proposed rule.