IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

NATIONAL PARKS CONSERVATION ASSOCIATION, MONTANA ENVIRONMENTAL INFORMATION CENTER, GRAND CANYON TRUST, SAN JUAN CITIZENS ALLIANCE, OUR CHILDREN'S EARTH FOUNDATION, PLAINS JUSTICE, POWDER RIVER BASIN RESOURCE COUNCIL, SIERRA CLUB, AND ENVIRONMENTAL DEFENSE FUND Plaintiffs, v. SCOTT PRUITT, in his official capacity as Administrator, United States Environmental Protection Agency, Defendant.	)	CIVIL ACTION NO. 1: 11-cv-01548 (ABJ)

PLAINTIFFS' STATEMENT OF POSITION AND MOTION TO ENFORCE DECREE

INTRODUCTION

The Court instructed the Plaintiffs to file a notice by October 13, 2017, stating their position on whether EPA's notice signed September 29, 2017 complies with the consent decree entered in this proceeding. *See* Oct. 6, 2017 Minute Order. For the reasons set forth below, Plaintiffs hereby state their position that EPA's action signed September 29, 2017 (Exhibit A hereto)[1] fails to comply with the consent decree. Plaintiffs further move the Court to order EPA to promulgate within 30 days a lawfully adopted final rule meeting the consent decree's requirements with respect to the Clean Air Act's best available retrofit technology ("BART")

[1] Exhibit to Joint Status Report (Oct. 2, 2017) (ECF Doc. No. 100-1) ("Prepublication Final Rule"). Because the document does not contain page numbers, Plaintiffs have added page numbers to the attached version to facilitate references to specific pages in the document.

requirements for Texas power plants.[2] Such a rule is long overdue to reduce the impact of haze-forming emissions from these plants across at least fifteen "Class I" national parks and wilderness, including such national treasures as Big Bend National Park in Texas, Carlsbad Caverns National Park in New Mexico, and Wichita Mountains National Wildlife Refuge in Oklahoma.[3]

EPA's September 29 action is a sham rule that flagrantly violates notice and comment procedures mandated by the Clean Air Act ("the Act"). Instead of finalizing a rule that was contemplated by the proposal, 82 Fed. Reg. 912 (Jan. 4, 2017) – a proposal that was the subject of extensive notice and comment (including a public hearing) – EPA has issued a drastically different rule that has never been subject to notice and comment. EPA's proposal specified source-specific pollution control requirements for Texas power plants subject to the Act's mandate for BART. The proposal set emission limits reflecting the use of modern pollution control technology. These limits would have cut haze-causing pollution from Texas power plants by more than 190,000 tons compared to recent emission levels.[4] But in the September 29 action, EPA abandoned its proposal to require source-specific pollution limits, and instead adopted an entirely new intrastate emissions trading program that did not appear in the proposal at all. That trading program will not require any individual power plant to reduce its emissions. And in contrast to the proposed rule, the trading rule is not expected to result in *any* reduction in

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[2] The parties have agreed that, given the particular nature of the disagreement between them, dispute resolution pursuant to paragraph 16 of the decree would not be fruitful.

[3] EPA, Technical Support Document for the Texas Regional Haze BART Federal Implementation Plan at 2 (Dec. 2016), *available at* https://www.regulations.gov/document?D=EPA-R06-OAR-2016-0611-0004 ("BART FIP TSD").

[4] BART FIP TSD at 2 ("Our proposed FIP to address Texas EGU BART is estimated to reduce annual emissions of SO2 by approximately 194,000 [tons per year], a larger reduction than projected under CAIR or CSAPR.").

haze-causing pollution below 2016 levels.[5] In fact the trading program would allow a potential *increase* of 74,813 tons above 2016 levels.[6]

The consent decree as amended required EPA to sign, by September 29, 2017, a notice or notices of "final rulemaking" that "collectively meet the regional haze implementation plan requirements" for BART for electric generating units ("EGUs") "that were due by December 17, 2007 under EPA's regional haze regulations." *See* Order Amending Consent Decree at ¶ 2(i) (Dec. 15, 2015) (ECF Doc. No. 86), amended Aug. 9, 2017 (ECF Doc. No. 91); *see also* Sept. 6, 2017 Minute Order (extending deadline to September 30, 2017). As further detailed below, an action taken in violation of notice and comment requirements is not a lawful final action and therefore does not comply with the decree.

BACKGROUND

Recognizing the "intrinsic beauty and historical and archaeological treasures" of the national parks and wilderness areas,[7] Congress established "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility" in the national parks and wilderness areas "which impairment results from manmade air pollution." 42 U.S.C. § 7491(a)(1). Sulfur dioxide pollution, nearly all of which comes from several dozen very large coal-burning power plants in Texas,[8] is one of the leading causes of visibility impairment in

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[5] EPA states that in 2016, the sources covered by the trading program emitted 218,291 tons of sulfur dioxide. Exhibit A at 133, Table 9. EPA states that the trading program limits annual emissions from covered sources to between 248,393 and 293,104 tons. *Id.* at 136-37. Therefore, the trading program authorizes covered sources to emit *more* than they actually emitted in 2016.

[6] Under the trading program, the maximum annual allowances are 293,104 tons, and actual emissions in 2016 were 218,291 tons. *See supra* note 5. 293,104 minus 218,291 is 74,813.

[7] H.R. Rep. No. 95-294, at 203-04 (1977), *reprinted in* 1977 U.S.C.C.A.N 1077, 1282.

[8] According to the 2011 National Emissions Inventory, 91% of all U.S. SO_2 emissions come from coal-fired electric power plants. Sierra Club Comments, Docket ID No. EPA-HQ-OAR-2014-0464-0420, at 3 (Mar. 31, 2016) ("Sierra Club Comments") (citing EPA, 2011 National Emissions Inventory (NEI) Data, https://www.epa.gov/air-emissions-inventories/2011-national-

numerous national parks and wilderness areas.[9] Sulfur dioxide also causes and exacerbates asthma and other respiratory diseases, leading to increased hospitalizations, and forms particulate matter that is linked to respiratory harms, heart diseases, and premature deaths.[10]

To implement the Clean Air Act's visibility protection mandate, EPA issued the Regional Haze Rule, which requires the states (or EPA where a state fails to act) to make "reasonable progress" toward eliminating human-caused visibility impairment at national parks and wilderness area by 2064. 40 C.F.R. § 51.308(d)(1), (d)(3). A key element of both the Clean Air Act and the Regional Haze Rule is the requirement to install best available retrofit technology at many of the nation's oldest and dirtiest sources. 42 U.S.C. § 7491(b)(2)(A); 40 C.F.R. § 51.308(e). Under the Regional Haze Rule, states were required to submit implementation plans addressing BART and ensuring reasonable progress toward the national visibility goal by December 2007. 40 C.F.R. § 51.308(b).

The Court has already noted the long history of failure by Texas and EPA to comply with the Clean Air Act's regional haze provisions.[11] In short, it has been 40 years since Congress first announced the requirement that states were to develop plans to install BART at large, aging pollution sources contributing significantly to impaired scenic views, 42 U.S.C. § 7491(b)(2). Ten years since EPA's due date for states to submit such plans came and went without Texas submitting a plan, 40 C.F.R. § 51.308(b); and five years have passed since the original deadline set forth in this Court's Consent Decree for EPA to take final action on a Texas haze plan. Consent Decree at 3-5. Since the Consent Decree was initially entered, the Plaintiffs have

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emissions-inventory-nei-data). At the time EPA developed the record for the final designations, 2011 was the most recent year for which data was available.

[9] 79 Fed. Reg. 74,818, 74,834 (Dec. 16, 2014)

[10] *See* 75 Fed. Reg. 35,520, 35,525 (June 22, 2010); 78 Fed. Reg. 3086, 3103 (Jan. 15, 2013).

[11] Order at 3-5 (Aug. 31, 2017) (ECF Doc. No. 96)

agreed to a number of extensions allowing EPA more time to finalize its Texas haze action due to EPA's claimed need for more time to address issues related to the details and technical soundness of its rulemaking. The longest single extension during this period was agreed upon in December 2015 after EPA had, in November 2014, issued a proposed plan to meet some of its statutory obligations for Texas regional haze. That proposal sought to address the BART requirement by relying on the Cross State Air Pollution Rule ("CSPAR") – an interstate pollution cap-and-trade program – as a substitute.[12] Under that program, an individual plant does not have to cut its emission of pollutants, and can even increase emissions, as long as it buys or trades for sufficient pollution "allowances" from other plants.

The December 2015 agreement allowed EPA to bifurcate finalization of the haze reduction requirements for Texas for two distinct elements required by the statute, one being the "reasonable progress" provisions, *see* 42 U.S.C. § 7491(b)(2), (g)(1), and the other being the plan to require aging power plants to meet limits corresponding to the installation of BART, *id.* § 7491(b)(2)(A), (g)(2).[13] Under the resulting Consent Decree amendment,[14] the final plan

[12] The proposal relied upon EPA's 2012 rule establishing that states with obligations under EPA's Cross State Air Pollution Rule for sulfur dioxide and/or nitrogen oxides need not implement "source-specific" emission limitations for the respective pollutants. 77 Fed. Reg. 33,642 (June 7, 2012). Plaintiffs Sierra Club and National Parks Conservation Association have challenged this rule in the D.C. Circuit. That challenge is pending. *See* Conservation Groups' Opening Brief, *Util. Air Regulatory Group v. EPA*, No. 12-1342 (D.C. Cir. Mar. 17, 2017) (ECF Doc. No. 1666640).

[13] Best Available Retrofit Technology is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility." 40 C.F.R. § 51.301.

[14] Order (Dec. 15, 2015) (ECF Doc. No. 86). *See also* June 20, 2014 Minute Order (ECF Doc. No. 82-C); EPA's Unopposed Motion to Amend the First Partial Consent Decree (June 18, 2015) (ECF Doc. No. 84); EPA's Unopposed Motion to Amend the First Partial Consent Decree (Dec. 7, 2015) (ECF Doc. No. 85).

addressing "reasonable progress" provisions remained due on December 9, 2015.[15] The second part of the amendment required EPA to take final action to promulgate and/or approve the BART portion of the plan by December 9, 2016, unless EPA proposed a *new* BART plan by that date, in which case the deadline for a final rule would be extended by another nine months to September 9, 2017.

The long-extended and tiered set of deadlines for the BART portion of EPA's obligations were grounded in EPA's representations to the Court that it needed to do additional analysis to promulgate a lawful plan. Previously, in a separate rulemaking, and pursuant to a different, now-invalidated analysis, EPA had proposed to rely on the Cross State Air Pollution Rule to satisfy the BART requirements for Texas, but the D.C. Circuit later invalided the Cross State Air Pollution Rule's sulfur dioxide trading program caps for Texas. *EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118 (D.C. Cir. 2015) ("*EME Homer II*"). The D.C. Circuit issued its decision after EPA's 2014 proposal to rely on the trading program as a substitute for BART in Texas. The court's decision was in response to a petition by the State of Texas and owners of large coal-fired power plants in Texas. As a result of *EME Homer II*, EPA determined it would have to evaluate whether Texas power plants would still be subject to the Cross State Air Pollution Rule for sulfur dioxide. If EPA could not simply finalize the 2014 proposal, EPA

[15] EPA promulgated a federal implementation plan ("FIP") for the "reasonable progress" portion of the plan, but that FIP was challenged in the Fifth Circuit and is now on remand to EPA. *See Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016). In the action dated September 29, 2017, EPA states that "the EPA is not determining at this time that this final action fully resolves the EPA's outstanding obligations with respect to reasonable progress that resulted from the Fifth Circuit's remand of our reasonable progress FIP. We intend to take future action to address the Fifth Circuit's remand." Exhibit A at 35. Thus, this element of EPA's mandatory duties under the Clean Air Act and the Consent Decree remains unfulfilled.

represented it would need even more time to finalize a rule because it would need to evaluate appropriate BART emission limits for each eligible source.[16]

Following this extension of time to complete the BART element of the Texas plan, on June 27, 2016, EPA issued a memorandum providing Texas the option of voluntarily adopting the Cross State Air Pollution Rule's pollution budgets as a way of avoiding the source-specific emission limits associated with Best Available Retrofit Technology.[17] Texas declined, unlike the other three states that were offered this option.[18]

Given that the *EME Homer II* decision effectively precluded EPA from imposing the Cross State Air Pollution Rule as a substitute for BART in Texas,[19] EPA proposed a new Best Available Retrofit Technology plan on December 9, 2016, published at 82 Fed. Reg. 912 (Jan. 4, 2017) (Exhibit C hereto) which triggered the Consent Decree's additional extension for finalizing the BART plan for Texas by September 9, 2017. That proposal found, among other things, that EPA could not continue to rely on the Cross State Air Pollution Rule's emission trading program to meet the BART requirements for sulfur dioxide emissions in Texas. 82 Fed.

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[16] EPA's Unopposed Motion to Amend the First Partial Consent Decree at 4-5 (Dec. 7, 2015) (ECF Doc. 85).

[17] Mem. from J. McCabe, Acting Assistant Administrator, EPA to Regional Air Division Directors, Re: The USEPA's Plan for Responding to the Remand of the Cross-State Air Pollution Rule Phase 2 SO_2 Budgets for Alabama, Georgia, South Carolina, and Texas (June 27, 2016), Docket ID No. EPA-HQ-OAR-2016-0598-0003; *see also* 81 Fed. Reg. 78,954, 78,959 n.35 (Nov. 10, 2016).

[18] Supplemental Notice by EPA Regarding EPA's Schedule For Completing Final Action On A Good Neighbor Federal Implementation Plan For Texas With Respect To The 1997 $PM_{2.5}$ Standards at 3, *Sierra Club v. EPA*, No. 1:10-cv-01541 (CKK) (D.D.C. Dec. 5, 2016) (ECF Doc. No. 87) (attached as Exhibit B). EPA proceeded to formally withdraw the federal implementation plan that had implemented the 2011 Cross State Air Pollution Rule's trading budgets for Texas. 82 Fed. Reg. 45,481, 45,487 (Sept. 29, 2017).

[19] *See, e.g.*, 81 Fed. Reg. 296, 302 (Jan. 5, 2016) ("Given the uncertainty arising from the remand of Texas' CSAPR budgets, we have concluded that it would not be appropriate to finalize our proposed determination to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas at this time.").

Reg. at 914-15. So the proposal instead set source-specific emission limits on sulfur dioxide for fourteen coal-fired boilers at Texas power plants. *E.g.*, 82 Fed. Reg. at 946-47 (Tables 33 and 34). The limits in the proposal reflected the pollution reductions that can be achieved with the best retrofit pollution control technology at each boiler. *See, e.g.*, *id.* at 939-46 (proposing BART determinations based on the use of new scrubbers or upgrades to existing scrubbers). EPA supported the proposed rule with extensive technical and legal documentation of its analysis of each of the five factors used to determine "best available retrofit technology," as required in the statute, 42 U.S.C. § 7491(g)(2), and applicable regulations, 40 C.F.R. § 51.308(e)(1)(ii)(A). Plaintiffs commented in strong support of this proposal, providing detailed technical analyses and additional legal support for EPA's conclusions,[20] in addition to evidence that the proposed rule would prevent tens of thousands of asthma attacks, 677 or more premature deaths, more than 105,000 lost work days every year, and would save more than $6.7 billion in public health and lost productivity costs annually.[21]

Twenty-two days before the September 9, 2017 deadline, EPA requested that this Court provide another lengthy delay to allow time for the State of Texas to develop a new state plan and for EPA to review and approve that hypothetical plan. The primary reason offered for the request was that the State of Texas "indicated that it still prefers the flexibilities inherent in a trading program and believes that it can develop an intrastate trading program that will succeed. . . ." EPA Br. at 11 (ECF Doc. No. 93-1). The Court rejected this request and required EPA to issue a federal plan by September 9, 2017 to the extent it had not approved a state plan by then.

[20] Earthjustice. National Parks Conservation Association, and Sierra Club Comments and Attachments (May 5, 2017), *available at* https://www.regulations.gov/document?D=EPA-R06-OAR-2016-0611-0083.

[21] Written Report of George D. Thurston Regarding the Public Health Benefits of EPA's Proposed Rulemaking at 18-19 (May 4, 2017), *available at* https://www.regulations.gov/document?D=EPA-R06-OAR-2016-0611-0072.

That deadline was later extended to September 30, 2017 in connection with Hurricane Harvey. Sept. 6, 2017 Minute Order.

In the notice dated September 29, 2017, EPA attempts another end-run around this Court's Order. Instead of finalizing the source-specific pollution control plan in the 2016 proposal, or a rule that is a logical outgrowth of the proposal, EPA creates out of whole cloth an intrastate pollution credit trading program – just as it sought to allow Texas to do in its previous, rejected, request to the Court – with the only explanation given that Texas and industry had requested this course of action in comments. Exhibit A at 15. As further detailed below, this attempt to adopt a rule entirely different from what was proposed flagrantly violates requirements for notice and comment rulemaking and renders EPA's action invalid.

ARGUMENT

I. EPA'S ACTION IS LEGALLY INVALID DUE TO VIOLATION OF NOTICE AND COMMENT REQUIREMENTS.

The core of EPA's September 29 action is adoption of a federal implementation plan pursuant to 42 U.S.C. § 7410(c) that consists of an intrastate pollution trading program for certain Texas sources. Under the Clean Air Act, a federal implementation plan cannot be adopted without following public notice and comment procedures set forth in 42 U.S.C. § 7607(d). *See* 42 U.S.C. § 7607(d)(1)(B), (d)(2)-(6). Among other things, EPA must first publish a proposed rule in the *Federal Register* that is accompanied by a statement of basis and purpose and specifies a comment period. *Id.* § 7607(d)(3). The statement of basis and purpose must include a summary of the factual data on which the proposed rule is based, the methodology used in obtaining and analyzing the data, and the major legal interpretations and policy considerations underlying the proposed rule. *Id.* EPA must allow any person to submit comments, and in addition, shall give interested persons an opportunity for the oral presentation of data, views, or arguments. *Id.* § 7607(d)(5). These and other public participation requirements in §7607(d) build on those in the Administrative Procedure Act, and are even more protective of notice and comments rights.

EPA did not follow these procedures with respect to the central component of its September 29 action – the intrastate trading program it invented for Texas after the Court would not allow EPA to put off its deadline to allow Texas to develop such a plan. The proposed rule contained no mention whatsoever of such a program, much less a summary of the factual data and new legal interpretations on which EPA ultimately relied to justify that program. Indeed, the word "trading" appears nowhere in the proposal at all. Nor was there even the slightest suggestion in the proposed rule that EPA might consider adopting an intrastate trading program for Texas in lieu of the source-specific retrofit controls that the proposal set out in detail with extensive justification. *See* 82 Fed. Reg. 912. Because EPA did not follow the required rulemaking procedures, its September 29 action is void and cannot serve as a basis for complying with the decree. *See, e.g.*, Memorandum Opinion at 7-9, *Sierra Club v. Whitman*, No. 1:00-cv-02206 (CKK) (D.D.C. July 10, 2002) ("July 10, 2002 Mem. Op."), *affirming in relevant part* 2002 WL 393069 (D.D.C. Mar. 11, 2002) (Attached as Exhibits D & E). As the Court in *Whitman* held, a rule issued without following adequate notice and comment procedures – including the requirement to adequately alert commenters of options being considered - does not qualify as a "final" rule sufficient to satisfy a nondiscretionary duty. *Id.* July 10, 2002 Mem. Op. at 6-9.

Although courts sometimes allow a rule to differ in limited ways from the proposal, they do so only where the rule can fairly be viewed as a "logical outgrowth" of the proposal. The logical outgrowth doctrine applies where the rule merely clarifies the proposal, or where the agency put commenters on notice that it was considering approaches different from the proposal. *See, e.g.*, *Daimler Trucks N. Am. v. EPA*, 737 F.3d 95 (D.C. Cir. 2013) (no logical outgrowth where proposal offered no indication agency was considering change that was ultimately adopted, and where change went beyond mere clarification). Here, EPA provided no notice that it was considering an intrastate trading program instead of source-specific emission limits.

EPA does not, and cannot, suggest that its trading program is just a clarification of the proposal. The central thrust of the proposal was to require source-specific pollution limits based on the best available retrofit technology for each source. In order to adopt its wholly different trading program, EPA had to add more than 60 pages of regulatory text that appeared nowhere in the proposal, and more than 20 pages of explanatory text. *See, e.g*, Exhibit A at 117-142, 156-221. And the program is dramatically different in substance from the proposal, so much so, in fact, that EPA said it was "not necessary to respond" to comments on the proposed source-specific rule. *See* Exhibit A at 39. Moreover, instead of requiring limits for each of the relevant plants reflective of the best available retrofit controls, which EPA anticipated would reduce sulfur dioxide emissions by more than 194,000 tons per year below 2016 levels,[22] EPA is instituting a trading program in which the emissions cap is *above* the plants' 2016 emissions.[23] Simply put, EPA proposed a rule that would cut emissions by nearly 200,000 tons per year,[24] and issued a rule that allows a net <u>increase</u> in emissions.

EPA's adoption of an entirely new program that was not even suggested in the proposal plainly does not qualify as a logical outgrowth. *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005) (logical outgrowth doctrine did not apply where rule was "surprisingly

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[22] *See supra* note 4.
[23] *See supra* note 5.
[24] *See supra* note 4.

distant" from proposal, as the court has "refused to allow agencies to use the rulemaking process to pull a surprise switcheroo on regulated entities"); *Int'l Union v. Mine Safety and Health Admin.*, 407 F.3d 1250, 1259-60 (D.C. Cir. 2005) ("The logical outgrowth doctrine does not extend to a final rule that is a brand new rule . . . nor does it apply where interested parties would have had to divine the Agency's unspoken thoughts."). EPA implies that its adoption of the trading program was justified because two Texas state agencies and two power companies filed comments advocating such an approach. Exhibit A at 15. But the fact that commenters advocated for a wholly different approach than proposed hardly gave notice to the public that the agency itself was proposing or even considering such an approach. The D.C. Circuit has "made clear that the fact that some commenters actually submitted comments addressing the final rule is of little significance. The agency must *itself* provide notice of a regulatory proposal." *Ass'n of Private Sector Colleges v. Duncan*, 681 F.3d 427, 462 (D.C. Cir. 2012) (emphasis in original).[25]

EPA might try to claim that Plaintiffs should file a petition for reconsideration with the agency pursuant to 42 U.S.C. § 7607(d)(7)(B), but that provision is merely an exhaustion requirement that parties sometimes need to follow in order to preserve an argument for presentation in a petition for review in the circuit court. It is hardly a license for EPA to knowingly violate notice and comment rulemaking requirements. Moreover, there is no statutory

[25] Nor is EPA's complete disregard of the required notice and comment procedures remedied by Plaintiffs Sierra Club and NPCA's comments against "relying on a BART alternative such as the C[ross] S[tate] A[ir] P[ollution] R[ule] trading program." Earthjustice. National Parks Conservation Association, and Sierra Club Comments and Attachments (May 5, 2017), *available at* https://www.regulations.gov/document?D=EPA-R06-OAR-2016-0611-0083, *supra* note 20, at 17. Plaintiffs submitted comments on this topic solely in response to industry comments at the January 10, 2017 public hearing, and to industry comments on the proposal to withdraw Texas from the Cross State Air Pollution Rule. *See, e.g.*, Transcript of January 10, 2017 Public Hearing on EPA's Clean Air Plan Proposal for Texas Regional Haze, Docket ID No. EPA-R06-OAR-2016-0611-0057, at 22. The comments were not based on, or responding to any actual or implied proposal by EPA itself to adopt such an alternative.

deadline for EPA's commencement or completion of reconsideration under 42 U.S.C. § 7607(d)(7)(B). The consent decree deadline would be effectively nullified if EPA could adopt a non-final or otherwise facially defective rule by the decree deadline and then stall or avoid adopting a lawful rule via a deadline-free reconsideration process. And even if there were a date-certain endpoint, resorting to the reconsideration process here would reward with further delay EPA's flagrant failure to follow the rulemaking timetable and procedures contemplated by the consent decree. The Court has already rejected EPA's request to amend the consent decree deadlines and should not countenance a *de facto* amendment due to EPA's noncompliance.

EPA's failure to provide notice of its major change in approach severely prejudices Plaintiffs and the public. Had EPA revealed a proposal to adopt the intrastate trading program at the time of proposal, Plaintiffs would have vigorously opposed that proposal. As noted above, the trading program is far weaker than the source-specific control proposal that EPA actually made. Moreover, Plaintiffs contend the trading program is unlawful and arbitrary on multiple grounds.

For example, in trying to demonstrate compliance with the Regional Haze Rule's strict analytical requirements for any BART alternative, EPA purports to rely on its "CSAPR better than BART" findings in a different rulemaking, Exhibit A at 49, even though EPA has explicitly noted that it can no longer lawfully rely on that finding. 82 Fed. Reg. at 45,487. Moreover, any reliance on the factual analysis underlying CSAPR would be arbitrary, because the Texas trading program excludes dozens of sources that had been subject to CSAPR. Exhibit A at 133-35. In 2016, those sources accounted for approximately 27,000 tons of sulfur dioxide pollution, *id*. at 135 – pollution that will be essentially uncontrolled under the new, less stringent trading program. Further, EPA's now-defunct CSAPR better than BART finding for Texas was predicated on emissions not exceeding 317,000 tons per year for the state. But according to EPA's own assessment, total allowable Texas sulfur dioxide emissions could exceed the CSAPR budget for the state.[26] Also, as noted, the trading rule is not expected to result in *any* reduction in haze-causing pollution, but instead allows for a potential *increase* of 74,813 tons above 2016 levels.[27] These and other significant defects in EPA's intrastate trading plan show how EPA's failure to provide an opportunity to comment was a violation with major substantive impacts.

II. BY ISSUING A RULE IN VIOLATION OF THE NOTICE AND COMMENT REQUIREMENTS, EPA VIOLATED THE DECREE

EPA's failure to observe the notice and comment requirements in the Clean Air Act means that the agency has failed to comply with the consent decree requirement that EPA sign a "notice of final rulemaking" containing actions "that collectively meet the BART requirements for EGUs that were due by December 17, 2007 under EPA's regional haze regulations." Order Amending Consent Decree at ¶ 2 (Dec. 15, 2015) (ECF Doc. No. 86) (adding a new paragraph, 4(a)(i)-(ii) to the First Partial Consent Decree) (emphasis added). A person may bring suit in district court to compel EPA to perform a nondiscretionary duty, while a suit seeking review of final EPA action may be brought in the circuit court. 42 U.S.C. §§ 7604(a), 7607(b)(1). Thus, the District Court has jurisdiction to determine whether EPA's nondiscretionary duties "have been performed in the first place." *Sierra Club v. Whitman*, No. 1:00-cv-02206 (CKK), 2002

[26] *See* Exhibit A at 136-37 (noting that the total allowable emissions that can be allocated to sources subject to the trading program is 293,104). This does not include the sources that had been subject to control under CSAPR, but are not subject to the new trading program. Based on 2016 emissions, those sources are expected to emit at least another 27,500 tons per year, *id.* at 133-34. Thus, the total allowable emissions for all Texas sources could exceed EPA's own 317,100 threshold for remaining better than BART.

[27] EPA states that in 2016, the sources covered by the trading program emitted 218,291 tons of sulfur dioxide. Exhibit A at 133, Table 9. EPA states that the trading program limits annual emissions from covered sources to between 248,393 and 293,104 tons. *Id.* at 137. Therefore, the trading program authorizes covered sources to emit up to 74,813 tons per year *more* than they actually emitted in 2016.

WL 393069, at *4, *adopted in relevant part*, July 10, 2002 Mem. Op. And where, as here, the EPA duty must be performed via notice and comment rulemaking, the District Court must determine whether the proper notice and comment procedures were correctly followed. July 10, 2002 Mem. Op. at 9.

Courts in this Circuit have held that an agency fails to perform a non-discretionary duty to adopt a final rule when it issues a purported rule in violation of notice and comment requirements. In *Sierra Club v. Whitman*, the Court held that EPA had failed to perform the mandatory duty at issue because EPA's proposal notice did not provide adequate notice to the public of the agency's intended action. *Id.* The notice was deficient because, among other things, "'[i]t would take no one less than a mindreader" to guess what EPA intended to do. *Id.* at 11 (citation omitted). So too here. *See also Sierra Club v. McCarthy*, 61 F. Supp. 3d 35, 41 (D.D.C. 2014) (holding that district court's order for EPA to take nondiscretionary action "remains unsatisfied" due to EPA's failure to follow notice and comment requirements). In sum, by signing a rule that violates the Clean Air Act's notice and comment requirements, EPA failed to perform the non-discretionary duty required by the consent decree.[28]

III. REMEDY

[28]In addition, EPA has not posted all of the record documents on its public web docket for this action, including important documents cited in the Prepublication Final Rule, such as legal and technical responses to comments. Plaintiffs reserve the right to raise any additional defects in EPA's action that might be revealed by such records or further review of the 9/29/2017 action. EPA's Prepublication Final Rule also does not yet meet the requirements of the decree because, as stated on the bottom of each page of that notice, it is "not the official version." An unofficial notice can hardly qualify as a "notice of final rulemaking." Further, because the Consent Decree requires EPA to finalize plans "*that collectively meet the BART requirements* that were due by December 17, 2007 under EPA's regional haze regulations," Plaintiffs reserve the right to raise any failure to meet these requirements as may be determined by a Court of Appeals in seeking to enforce the Consent Decree at a later date. *See* Order Amending Consent Decree ¶ 2(i) (Dec. 15, 2015) (ECF Doc. No. 86), as amended ECF Doc. No. 91 (emphasis added). EPA will not have fully complied with its obligations under the consent decree until the appropriate courts complete their review, ensuring that the rules signed by EPA meet those requirements.

"District courts have the authority to enforce the terms of their mandates." *Sierra Club v. McCarthy*, 61 F. Supp. 3d at 39 (citation omitted). The Court "should grant a motion to enforce if a 'prevailing plaintiff demonstrates that a defendant has not complied with a judgment entered against it.'" *Id.* For all the foregoing reasons, EPA has failed to comply with this Court's order for promulgation of a notice of final rulemaking meeting the BART requirements for Texas power plants in EPA's rules, and an enforcement order is warranted.[29]

As a remedy, Plaintiffs respectfully request that the Court order EPA to complete promulgation of a final rule that complies with all notice and comment procedures within 30 days. This time frame is justified because EPA already has a BART rule proposal that that has undergone an extensive notice and comment process, namely the proposed rule published on January 4, 2017. Thirty days should be ample time for EPA to adopt a final rule based on that proposal, particularly given that the agency has had more than five months to review and address comments.[30] To give EPA more time to go through a <u>new</u> notice and comment process on a <u>different</u> proposal – namely, EPA's intrastate trading plan – would severely flout the consent decree deadlines. The decree provided for the proposed rule to be signed no later than December 9, 2016, ECF Doc. No. 86 at ¶ 2(ii)(a), and the final rule to be signed by September 9, 2017, *id.* at ¶ 2(ii)(b), which was extended to September 30, 2017, *see* Sept. 6, 2017 Minute Order. There is no provision in the decree for giving EPA more time to start the whole process over again.

[29] This motion addresses only the BART plan requirements of the decree. The "reasonable progress" plan has been stayed by the Fifth Circuit and is under review by EPA on voluntary remand. Plaintiffs reserve the right to seek separate relief with respect to that portion of the plans required by the decree.

[30] The comment period on the proposal closed on May 5, 2017. EPA would have had 7 months to review and address comments had the agency not granted a 60-day extension of its initial comment period, which ended March 5, 2017

Moreover, the BART rule was bifurcated and delayed past the 2015 deadline for the other portions of the Texas regional haze program only upon EPA's representation that it would need extra time to issue a new proposal for BART. EPA earned an additional year of delay by issuing a new proposal, then proceeded to scrap that proposal. The Court should not reward EPA's bait and switch with further delay.

An extension for a new notice and comment rulemaking also would exacerbate the decade of delay by Texas and EPA in finalizing a BART rule for Texas. Under the statutory timetables, BART limits should have been not only adopted but all pollution controls should have been installed and operating in Texas by June 17, 2015. This would have achieved cleaner air in the parks much sooner, and would likely have saved many lives. Further delay at this stage would flout the statute, and leave parks and wilderness areas without the protection Congress mandated.

DATED October 13, 2017.

Respectfully submitted,

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

NATIONAL PARKS CONSERVATION ASSOCIATION, MONTANA ENVIRONMENTAL INFORMATION CENTER, GRAND CANYON TRUST, SAN JUAN CITIZENS ALLIANCE, OUR CHILDREN'S EARTH FOUNDATION, PLAINS JUSTICE, POWDER RIVER BASIN RESOURCE COUNCIL, SIERRA CLUB, AND ENVIRONMENTAL DEFENSE FUND Plaintiffs, v. SCOTT PRUITT, in his official capacity as Administrator, United States Environmental Protection Agency, Defendant.	CIVIL ACTION NO. 1: 11-cv-01548 (ABJ)

[PROPOSED] ORDER

On Plaintiffs' motion of October 13, 2017 for enforcement of the first partial consent decree as amended, and based on review of the other filings related thereto, it is hereby ORDERED that the motion is granted.

The defendant Scott Pruitt, Administrator of the United States Environmental Protection Agency, is hereby ORDERED to, no later than 30 days of the date of this order, promulgate a final rule adopting a federal implementation plan for Texas to meet the BART requirements for EGUs that were due by December 17, 2007 under EPA's regional haze regulations, except where, by such deadline EPA has, for Texas, promulgated a notice of final rulemaking unconditionally approving a SIP or promulgating a partial FIP and unconditional approval of a portion of a SIP, that collectively meet the regional haze implementation plan requirements that were due by December 17, 2007 under EPA's regional haze regulations. The foregoing actions shall be completed in full compliance with all applicable notice and comment rulemaking requirements under statute and caselaw, and must be limited to actions of which the public was given ample notice in the notice(s) of proposed rulemaking required by the Consent Decree.

DATED____________

____
HON. AMY BERMAN JACKSON
United States District Judge

Exhibit A

* Because the document does not contain page numbers, Plaintiffs have added page numbers to the attached version to facilitate references to specific pages in the document.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA-R06-OAR-2016-0611; FRL-___________Region 6]

Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or Act), the Environmental Protection Agency (EPA) is finalizing a partial approval of the 2009 Texas Regional Haze State Implementation Plan (SIP) submission and a Federal Implementation Plan (FIP) for Texas to address certain outstanding requirements. Specifically, the EPA is finalizing determinations regarding best available retrofit technology (BART) for electric generating units (EGUs) in the State of Texas. To address the BART requirement for sulfur dioxide (SO_2), the EPA is finalizing an alternative to BART that consists of an intrastate trading program addressing the SO_2 emissions from certain EGUs. To address the BART requirement for oxides of nitrogen (NO_X), we are finalizing our proposed determination that Texas' participation in the Cross-State Air Pollution Rule's (CSAPR) trading program for ozone-season NO_X qualifies as an alternative to BART. We are approving Texas' determination that its EGUs are not subject to BART for particulate matter (PM). Finally, we are disapproving portions of several SIP revisions submitted to satisfy the CAA requirement to address interstate visibility transport for six national ambient air quality standards (NAAQS): (1) 1997 8-hour ozone, (2) 1997 fine particulate matter ($PM_{2.5}$) (annual and 24-hour), (3) 2006 $PM_{2.5}$ (24-hour), (4) 2008 8-hour ozone, (5) 2010 1-hour nitrogen dioxide (NO_2) and (6) 2010 1-hour SO_2. We are finding that the BART alternatives to address

SO_2 and NO_X BART at Texas' EGUs meet the interstate visibility transport requirements for these NAAQS.

DATES: This final rule is effective on [**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER**].

ADDRESSES: The EPA has established a docket for this action under Docket ID No. . EPA-R06-OAR-2016-0611. All documents in the docket are listed on the *http://www.regulations.gov* web site. Although listed in the index, some information is not publicly available, *e.g.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute therefore is not posted to regulations.gov. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at EPA Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202-2733.

FOR FURTHER INFORMATION CONTACT: Michael Feldman at Feldman.Michael@epa.gov or 214-665-9793

SUPPLEMENTARY INFORMATION: Throughout this document wherever "we," "us," or "our" is used, we mean the EPA.

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I. Background

A. Regional Haze

Regional haze is visibility impairment that is produced by a multitude of sources and activities that are located across a broad geographic area and emit $PM_{2.5}$ (e.g., sulfates, nitrates, organic carbon (OC), elemental carbon (EC), and soil dust), and its precursors (e.g., SO_2, NO_X, and, in some cases, ammonia (NH_3) and volatile organic compounds (VOCs)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that can be seen. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects, such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the "Interagency Monitoring of Protected Visual Environments" (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national parks and wilderness areas. In 1999, the average visual range[1] in many Class I areas (i.e., national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States was 100-150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range was less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions.[2] CAA programs have reduced some haze-causing pollution, lessening some visibility impairment and resulting in partially improved average visual ranges.[3]

CAA requirements to address the problem of visibility impairment are continuing to be addressed and implemented. In Section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the prevention of any future, and the remedying of any existing man-made impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I Federal areas.[4] On December 2, 1980, EPA promulgated regulations to address visibility impairment in Class I areas that is "reasonably attributable" to a single source or small group of sources, i.e., "reasonably attributable visibility

[1] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.
[2] 64 FR 35715 (July 1, 1999).
[3] An interactive "story map" depicting efforts and recent progress by EPA and states to improve visibility at national parks and wilderness areas may be visited at: http://arcg.is/29tAbS3.
[4] Areas designated as mandatory Class I Federal areas consist of National Parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to "mandatory Class I Federal areas." Each mandatory Class I Federal area is the responsibility of a "Federal Land Manager." 42 U.S.C. 7602(i). When we use the term "Class I area" in this action, we mean a "mandatory Class I Federal area."

impairment."[5] These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling, and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues, and we promulgated regulations addressing regional haze in 1999.[6] The Regional Haze Rule revised the existing visibility regulations to integrate into the regulations provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in our visibility protection regulations at 40 CFR 51.300–309. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. States were required to submit the first implementation plan addressing regional haze visibility impairment no later than December 17, 2007.[7]

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often under-controlled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress toward the natural visibility goal, including a requirement that certain categories of existing major stationary sources[8] built between 1962 and 1977 procure, install and operate the "Best Available Retrofit Technology" (BART). Larger "fossil-fuel fired steam electric plants" are included among the

[5] 45 FR 80084 (Dec. 2, 1980).
[6] 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P (Regional Haze Rule).
[7] *See* 40 CFR 51.308(b). EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).
[8] *See* 42 U.S.C. 7491(g)(7) (listing the set of "major stationary sources" potentially subject-to-BART).

BART source categories. Under the Regional Haze Rule, states are directed to conduct BART determinations for "BART-eligible" sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. The evaluation of BART for EGUs that are located at fossil-fuel-fired power plants having a generating capacity in excess of 750 megawatts must follow the "Guidelines for BART Determinations Under the Regional Haze Rule" at appendix Y to 40 CFR Part 51 (hereinafter referred to as the "BART Guidelines"). Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or alternative program as long as the alternative provides greater reasonable progress towards improving visibility than BART. 40 CFR 51.308(e)(2) specifies how a state must conduct the demonstration to show that an alternative program will achieve greater reasonable progress than the installation and operation of BART. 40 CFR 51.308(e)(2)(i)(E) requires a determination under 40 CFR 51.308 (e)(3) or otherwise based on the clear weight of evidence that the trading program or other alternative measure achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources. Specific criteria for determining if an alternative measure achieves greater reasonable progress than source-specific BART are set out in 40 CFR 51.308(e)(3). Finally, 40 CFR 51.308(e)(4) states that states participating in CSAPR need not require BART-eligible fossil fuel-fired steam electric plants to install, operate, and maintain BART for the pollutant covered by CSAPR.

Under section 110(c) of the CAA, whenever we disapprove a mandatory SIP submission in whole or in part, we are required to promulgate a FIP within two years unless the state corrects the deficiency and we approve the new SIP submittal.

B. Interstate Transport of Pollutants that Affect Visibility

Section 110(a) of the CAA directs states to submit a SIP that provides for the implementation, maintenance, and enforcement of each NAAQS, which is commonly referred to as an infrastructure SIP. Among other things, CAA section 110(a)(2)(D)(i)(II) requires that SIPs contain adequate provisions to prohibit interference with measures required to protect visibility in other states. This is referred to as "interstate visibility transport." SIPs addressing interstate visibility transport are due to the EPA within three years after the promulgation of a new or revised NAAQS (or within such shorter period as we may prescribe). A state's failure to submit a complete, approvable SIP for interstate visibility transport creates an obligation for the EPA to promulgate a FIP to address this requirement.

C. Previous Actions Related to Texas Regional Haze

On March 31, 2009, Texas submitted a regional haze SIP to the EPA that included reliance on Texas' participation in the Clean Air Interstate Rule (CAIR) as an alternative to BART for SO_2 and NO_X emissions from EGUs.[9] This reliance was consistent with the EPA's regulations at the time that Texas developed its regional haze plan,[10] but at the time that Texas submitted this SIP to the EPA, the D.C. Circuit had remanded CAIR (without vacatur).[11] The court left CAIR and our CAIR FIPs in place in order to "temporarily preserve the environmental values covered by CAIR" until we could, by rulemaking, replace CAIR consistent with the court's opinion. The EPA promulgated CSAPR, a revised multi-state trading program to replace

[9] CAIR required certain states, including Texas, to reduce emissions of SO_2 and NOx that significantly contribute to downwind nonattainment of the 1997 NAAQS for fine particulate matter and ozone. See 70 FR 25152 (May 12, 2005).
[10] S*ee* 70 FR 39104 (July 6, 2005).
[11] *See North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008), *modified*, 550 F.3d 1176 (D.C. Cir. 2008).

CAIR, in 2011[12] (and revised it in 2012[13]). CSAPR established FIP requirements for a number of states, including Texas, to address the states' interstate transport obligation under CAA section 110(a)(2)(D)(i)(I). CSAPR requires affected EGUs in these states to participate in the CSAPR trading programs and establishes emissions budgets that apply to the EGUs' collective annual emissions of SO_2 and NO_X, as well as seasonal emissions of NO_X. Following issuance of CSAPR, the EPA determined that CSAPR would achieve greater reasonable progress towards improving visibility than would source-specific BART in CSAPR states.[14] We revised the Regional Haze Rule to allow states that participate in CSAPR to rely on participation in the trading programs in lieu of requiring EGUs in the state to install BART controls.

In the same action that EPA determined that states could rely on CSAPR to address the BART requirements for EGUs, EPA issued a limited disapproval of a number of states' regional haze SIPs, including the 2009 SIP submittal from Texas, due to the states' reliance on CAIR, which had been replaced by CSAPR.[15] The EPA did not immediately promulgate a FIP to address the limited disapproval of Texas' regional haze SIP in order to allow more time for the EPA to assess the remaining elements of the 2009 Texas SIP submittal. In December 2014, we proposed an action to address the remaining regional haze obligations for Texas.[16] In that action, we proposed, among other things, to rely on CSAPR to satisfy the NO_X and SO_2 BART requirements for Texas' EGUs; we also proposed to approve the portions of the SIP addressing PM BART requirements for the state's EGUs. Before that rule was finalized, however, the D.C.

[12] 76 FR 48207 (Aug. 8, 2011).
[13] CSAPR was amended three times in 2011 and 2012 to add five states to the seasonal NO_X program and to increase certain state budgets. 76 FR 80760 (December 27, 2011); 77 FR 10324 (February 21, 2012); 77 FR 34830 (June 12, 2012).
[14] 77 FR 33641 (June 7, 2012).
[15] *Id*.
[16] 79 FR 74818 (Dec. 16, 2014).

Circuit issued a decision on a number of challenges to CSAPR, denying most claims, but remanding the CSAPR emissions budgets of several states to the EPA for reconsideration, including the Phase 2 SO_2 and seasonal NO_X budget for Texas.[17] Due to potential impacts of the remanded budgets on the EPA's 2012 determination that CSAPR would provide for greater reasonable progress than BART, we did not finalize our decision to rely on CSAPR to satisfy the SO_2 and NO_X BART requirements for Texas EGUs.[18] Additionally, because our proposed action on the PM BART provisions for EGUs was dependent on how SO_2 and NO_X BART were satisfied, we did not take final action on the PM BART elements of Texas' regional haze SIP. In January 2016, we finalized action on the remaining aspects of the December 2014 proposal. That rulemaking was challenged, however, and in December 2016, following the submittal of a request by the EPA for a voluntary remand of the parts of the rule under challenge, the Fifth Circuit Court of Appeals remanded the rule in its entirety.[19]

On October 26, 2016, the EPA finalized an update to CSAPR to address the interstate transport requirements of CAA section 110(a)(2)(D)(i)(I) with respect to the 2008 ozone NAAQS (CSAPR Update).[20] The EPA also responded to the D.C. Circuit's remand of certain CSAPR seasonal NO_X budgets in that action. As to Texas, the EPA withdrew Texas's seasonal NO_X budget finalized in CSAPR to address the 1997 ozone NAAQS. However, in that same action, the EPA promulgated a FIP with a revised seasonal NO_X budget for Texas to address the

[17] *EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118, 132 (D.C. Cir. 2015).
[18] 81 FR 296 (Jan. 5, 2016).
[19] *Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016).
[20] 81 FR 74504 (Oct. 26, 2016).

2008 ozone NAAQS.[21] Accordingly, Texas remains subject to the CSAPR seasonal NO_X requirements.

On November 10, 2016, in response to the D.C. Circuit's remand of Texas's CSAPR SO_2 budget, we proposed to withdraw the FIP provisions requiring EGUs in Texas to participate in the CSAPR trading programs for annual emissions of SO_2 and NO_X.[22] We also proposed to reaffirm that CSAPR continues to provide for greater reasonable progress than BART following our actions taken to address the D.C. Circuit's remand of several CSAPR emissions budgets. On September 21, 2017, we finalized the withdrawal of the FIP provisions for annual emissions of SO_2 and NO_X for EGUs in Texas[23] and affirmed our proposed finding that the EPA's 2012 analytical demonstration remains valid and that participation in CSAPR as it now exists meets the Regional Haze Rule's criteria for an alternative to BART.

II. Our Proposed Actions

A. Regional Haze

On January 4, 2017, we proposed a FIP to address the BART requirements for Texas' EGUs. In that action, we proposed to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs.[24] This portion of our proposal was based on the CSAPR Update and our separate November 10, 2016 proposed finding that the EPA's actions in response to the D.C. Circuit's remand would not adversely impact our 2012

[21] 81 FR 74504, 74524-25.
[22] 81 FR 78954.
[23] Texas continues to participate in CSAPR for ozone season NO_X. See final action signed September 21, 2017 available at *regulations.gov* in Docket No. EPA-HQ-OAR-2016-0598
[24] 82 FR 912, 914-15 (Jan. 4, 2017).

demonstration that participation in CSAPR meets the Regional Haze Rule's criteria for alternatives to BART.[25] We noted that we could not finalize this portion of our proposed FIP unless and until we finalized our proposed finding that the set of actions taken by the EPA in response to the D.C. Circuit's remand of certain CSAPR budgets would not adversely impact our prior determination that CSAPR provides for greater reasonable progress than BART. As noted in section I.C, on September 21, 2017, we finalized our proposed finding that EPA's 2012 analytical demonstration remains valid and that participation in CSAPR as it now exists meets the Regional Haze Rule's criteria for an alternative to BART.

Also as noted in section I.C, as part of our November 10, 2016 proposed action in response to the D.C. Circuit's remand of Texas' SO_2 CSAPR budget, we also proposed to withdraw the FIP provisions requiring EGUs in Texas to participate in the CSAPR trading programs for annual emissions of SO_2 and NO_X.[26] In our January 4, 2017 proposed action on BART requirements for Texas EGUs, we accordingly proposed that because Texas would no longer be participating in the CSAPR program for SO_2, and thus would no longer be eligible to rely on participation in CSAPR as an alternative to source-specific EGU BART for SO_2 under 40 CFR 51.308(e)(4), our regional haze FIP would need to include the identification of BART-eligible EGU sources, screening of sources to identify subject-to-BART sources, and source-by-source determinations of SO_2 BART controls as appropriate. For those EGU sources we proposed to find subject to BART, we proposed to promulgate source-specific SO_2 requirements. We also proposed to disapprove Texas' BART determinations for PM from EGUs. In place of these determinations, we proposed to promulgate source-specific PM BART requirements for

[25] 81 FR 74504 (Nov. 10, 2016).
[26] 81 FR 78954.

EGUs that we proposed to find subject to BART. Previously, we proposed to approve the EGU BART determinations for PM in the Texas regional haze SIP and this proposal has never been withdrawn.[27] At that time, CSAPR was an appropriate alternative for SO_2 and NO_X BART for EGUs. The Texas Regional Haze SIP included a pollutant-specific screening analysis for PM to demonstrate that Texas EGUs were not subject to BART for PM. In a 2006 guidance document,[28] the EPA stated that pollutant-specific screening can be appropriate where a state is relying on a BART alternative to address both NO_X and SO_2 BART.

B. Interstate Transport of Pollutants that Affect Visibility

In our January 5, 2016 final action[29] we disapproved the portion of Texas' SIP revisions intended to address interstate visibility transport for six NAAQS, including the 1997 8-hour ozone and 1997 $PM_{2.5}$.[30] That rulemaking was challenged, however, and in December 2016, following the submittal of a request by the EPA for a voluntary remand of the parts of the rule under challenge, the Fifth Circuit Court of Appeals remanded the rule in its entirety without vacatur.[31] In our January 4, 2017 proposed action we proposed to reconsider the basis of our prior disapproval of Texas' SIP revisions addressing interstate visibility transport under CAA section 110(a)(2)(D)(i)(II) for six NAAQS. We proposed that Texas' SIP submittals addressing interstate visibility transport for the six NAAQS were not approvable because they relied solely

[27] 79 FR 74817, 74853-54 (Dec. 16, 2014).
[28] *See* discussion in Memorandum from Joseph Paisie to Kay Prince, "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations," July 19, 2006.
[29] 81 FR 296 (Jan. 5, 2016).
[30] Specifically, we previously disapproved the relevant portion of these Texas' SIP submittals: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). 79 FR 74818, 74821; 81 FR 296, 302.
[31] *Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016).

on Texas' 2009 Regional Haze SIP to ensure that emissions from Texas did not interfere with required measures in other states. Texas' Regional Haze SIP, in turn, relied on the implementation of CAIR as an alternative to EGU BART for SO_2 and NO_X.[32] We proposed a FIP to fully address Texas' interstate visibility transport obligations for: (1) 1997 8-hour ozone, (2) 1997 $PM_{2.5}$ (annual and 24-hour), (3) 2006 $PM_{2.5}$ (24-hour), (4) 2008 8-hour ozone, (5) 2010 1-hour NO_2 and (6) 2010 1-hour SO_2. The proposed FIP was based on our finding that our proposed action to fully address the BART requirements for Texas EGUs was adequate to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states in accordance with CAA section 110(a)(2)(D)(i)(II).

III. Summary of Our Final Decisions

A. Regional Haze

When we finalized a limited disapproval of Texas' 2009 regional haze SIP for its reliance on CAIR participation as a BART alternative, we did not immediately finalize a CSAPR-better-than-BART FIP for Texas, as we had proposed for Texas and ultimately finalized for twelve other states. Instead of finalizing a CSAPR-better-than-BART FIP for Texas, the EPA acknowledged that we needed more time to assess the Texas regional haze SIP in regard to aspects other than its reliance on CAIR as an alternative to BART.[33] As the EPA has continued to assess how best to address the regional haze obligations for Texas, Texas has not submitted a SIP revision to address the prior disapproval, so the EPA has a remaining obligation to address BART requirements for Texas EGUs.

[32] *EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118, 133-34 (D.C. Cir. 2015) (holding that SIPs based on CAIR were unapprovable to fulfill good neighbor obligations).
[33] 77 FR 33641, 33654 (June 7, 2012).

After assessing how we should address BART for Texas EGUs, we believe that our initial 2011 proposal, to treat Texas like other similarly situated CSAPR states, was an appropriate and regionally consistent approach. As discussed above, in 2014, we proposed that CSAPR would satisfy the NO_X and SO_2 BART requirements for Texas EGUs. [34] However, we did not finalize this part of the 2014 proposal in the action taken on January 5, 2016. [35] Given EPA's response to the D.C. Circuit remand of certain CSAPR emission budgets, we can no longer rely on CSAPR for Texas' SO_2 BART requirements. Based on comments we received in response to our January 2017 proposal, and giving particular weight to the views expressed by Texas, we are finalizing various determinations to ensure satisfaction of the BART requirement for EGUs in Texas. Of particular note, in making our final decision for the SO_2 BART requirement for EGUs, we centered our focus on a timely comment letter received from the Texas Commission on Environmental Quality (TCEQ) and the Public Utility Commission of Texas (PUC). This comment urged us to consider as a BART alternative the concept of emission caps using CSAPR allocations. We also received similar comments from Luminant and American Electric Power (AEP). Based upon the comments, we are proceeding to address the SO_2 BART requirement for EGUs under a BART alternative. The EPA finds that, because this BART alternative will result in SO_2 emissions from Texas EGUs that will be similar to emissions anticipated under CSAPR, the alternative is an appropriate approach for addressing Texas' SO_2 BART obligations.

[34] 79 FR 74817, 74823 (December 16, 2014) ("We propose to replace Texas' reliance on CAIR to satisfy the BART requirement for EGUs with reliance on CSAPR."). This part of the 2014 proposal was not finalized in the action taken on January 5, 2016, that has since been remanded by the Fifth Circuit Court of Appeals. 81 FR 295.

[35] Final action taken on January 5, 2016, that has since been remanded by the Fifth Circuit Court of Appeals. 81 FR 295.

Specifically, the BART alternative is justified "based on the clear weight of the evidence" that the alternative achieves greater reasonable progress than would be achieved through BART. *See* 40 CFR 51.308(e)(2)(E). The program is designed to accomplish environmental and visibility results by achieving emission levels that will be the same as or better than the emission levels that would have been obtained by state participation in the interstate CSAPR program as finalized and amended in 2011 and 2012, which EPA first deemed to be better than BART for NO_X and SO_2 in a 2012 regulatory action.[36] The TCEQ and EPA recently signed a memorandum of agreement (MOA) to work together to develop a SIP revision addressing interstate visibility transport requirements and BART requirements for EGUs with a BART alternative trading program starting from CSAPR as allowed under the Regional Haze Rule (40 C.F.R. 51.308(e)).[37] Texas envisions that the FIP measures that serve to satisfy this BART requirement will be replaced by a future SIP submission following the approach described in the MOA that may be approved as meeting the requirements of the CAA and the Regional Haze Rule. EPA policy consistently favors that states will exercise their SIP authority to avoid need for promulgation and continued implementation of measures under FIP authority. In the absence of a SIP to address the SO_2 BART requirement for Texas EGUs, however, EPA finds it necessary to address the requirement under its FIP authority, and the details of how this is addressed and the accompanying justification are further discussed below under Section III.A.3, "SO_2 BART."

[36] 77 FR 33641 (June 7, 2012).
[37] See Memorandum of Agreement Between the Texas Commission on Environmental Quality and the Environmental Protection Agency Regarding a State Implementation Plan to Address Certain Regional Haze and Interstate Visibility Transport Requirements Pursuant to Sections 110 and 169A of the Clean Air Act, Signed August 14, 2017.

The Regional Haze Rule requires that SIP or FIP measures be in place to ensure that BART is satisfied for all subject-to-BART EGUs and all haze-causing pollutants. For ease of summarization, we will detail the relevant final decisions for each of the haze-causing pollutants: PM, NO_X, and SO_2.[38] In our final decisions today, the relevant BART requirement for all BART-eligible coal-fired units and a number of BART-eligible gas- or gas/fuel oil-fired units will be encompassed by BART alternatives for NO_X and SO_2 such that we do not deem it necessary to finalize subject-to-BART findings for these EGUs for these pollutants. The remaining BART-eligible EGUs not covered by the SO_2 BART alternative have been determined to be not subject to BART based on the methodologies utilizing model plants and CALPUFF modeling as described in our proposed rule and BART Screening technical support document (TSD). Therefore, we are approving the portion of the Texas Regional Haze SIP that addresses the BART requirement for EGUs for PM, we are relying upon Texas EGUs' continued participation in the CSAPR program to serve as a BART alternative for NO_X, and we are promulgating an intrastate trading FIP to address the SO_2 BART requirements for EGUs.

1. BART-Eligible Units

BART-eligible sources are those sources which have the potential to emit 250 tons per year or more of a visibility-impairing air pollutant, which were ”in existence” on August 7, 1977 but not ”in operation” before August 7, 1962, and whose operations fall within one or more of 26 specifically listed source categories.[39] As discussed in detail in our proposal and the BART FIP TSD, our analysis of BART-eligible EGUs started with the list of BART-eligible sources

[38] In this action, we did not consider VOCs and ammonia among visibility-impairing pollutants for several reasons, as discussed in the TSD.
[39] 40 CFR 51.301.

provided by TCEQ in the 2009 Texas Regional Haze SIP. Based on additional information from potential BART-eligible sources and the U.S. Energy Information Administration (EIA), we converted Texas' facility-specific BART-eligible EGU list to a unit-specific BART-eligible EGU list, eliminated those units that have retired, and verified the BART-eligibility of each remaining unit. We noted in our proposal that Texas' list omitted some sources that we had identified as BART-eligible. We are finalizing the identification of BART-eligible units as proposed. A "BART-eligible source" is the collection of BART-eligible units at a facility. Table 1 shows the list of EGUs in Texas that are BART-eligible:

Table 1. Summary of BART-Eligible Units

Facility	**Unit**
Barney M. Davis (Talen/Topaz)	1
Big Brown (Luminant)	1
Big Brown (Luminant)	2
Cedar Bayou (NRG)	CBY1
Cedar Bayou (NRG)	CBY2
Coleto Creek (Dynegy[40])	1
Dansby (City of Bryan)	1
Decker Creek (Austin Energy)	1
Decker Creek (Austin Energy)	2
Fayette (LCRA)	1
Fayette (LCRA)	2
Graham (Luminant)	2
Greens Bayou (NRG)	5

[40] Dynegy purchased the Coleto Creek power plant from Engie in February, 2017. Note that Coleto Creek may still be listed as being owned by Engie in some of our supporting documentation which was prepared before that sale.

Handley (Exelon)	3
Handley (Exelon)	4
Handley (Exelon)	5
Harrington Station (Xcel)	061B
Harrington Station (Xcel)	062B
J T Deely (CPS Energy)	1
J T Deely (CPS Energy)	2
Jones Station (Xcel)	151B
Jones Station (Xcel)	152B
Knox Lee Power Plant (AEP)	5
Lake Hubbard (Luminant)	1
Lake Hubbard (Luminant)	2
Lewis Creek (Entergy)	1
Lewis Creek (Entergy)	2
Martin Lake (Luminant)	1
Martin Lake (Luminant)	2
Martin Lake (Luminant)	3
Monticello (Luminant)	1
Monticello (Luminant)	2
Monticello (Luminant)	3
Newman (El Paso Electric)	2
Newman (El Paso Electric)	3
Newman (El Paso Electric)	4
Nichols Station (Xcel)	143B
O W Sommers (CPS Energy)	1
O W Sommers (CPS Energy)	2
Plant X (Xcel)	4
Powerlane (City of Greenville)	ST1
Powerlane (City of Greenville)	ST2

Powerlane (City of Greenville)	ST3
R W Miller (Brazos Elec. Coop)	1
R W Miller (Brazos Elec. Coop)	2
R W Miller (Brazos Elec. Coop)	3
Sabine (Entergy)	2
Sabine (Entergy)	3
Sabine (Entergy)	4
Sabine (Entergy)	5
Sim Gideon (LCRA)	1
Sim Gideon (LCRA)	2
Sim Gideon (LCRA)	3
Spencer (City of Garland)	4
Spencer (City of Garland)	5
Stryker Creek (Luminant)	ST2
Trinidad (Luminant)	6
Ty Cooke (City of Lubbock)	1
Ty Cooke (City of Lubbock)	2
V H Braunig (CPS Energy)	1
V H Braunig (CPS Energy)	2
V H Braunig (CPS Energy)	3
WA Parish (NRG)	WAP4
WA Parish (NRG)	WAP5
WA Parish (NRG)	WAP6
Welsh Power Plant (AEP)	1
Welsh Power Plant (AEP)	2
Wilkes Power Plant (AEP)	1
Wilkes Power Plant (AEP)	2
Wilkes Power Plant (AEP)	3

2. Subject-to-BART Sources

As discussed elsewhere, it is unnecessary to finalize the subject-to-BART determinations for BART-eligible sources that are covered by the BART alternatives for SO_2 and NO_X. The BART alternatives cover both BART-eligible and non-BART eligible sources. This combination provides for greater reasonable progress than source-specific BART. Even if a unit were individually found to not be subject to BART, its participation in the BART alternative contributes to the finding that the program provides greater reasonable progress than BART. We note that all BART-eligible EGUs in Texas are either covered by the BART alternative or have screened out of being subject to BART. The section below that discusses our final SO_2 BART determination lists those units covered by the BART alternative program and identifies which of those units are BART-eligible. As discussed in section III.A.4 below, we are approving the portion of the 2009 Texas Regional Haze SIP that determined that no PM BART determinations are needed for BART-eligible EGUs in Texas.

For those BART-eligible EGUs that are not covered by the BART alternative for SO_2, we are finalizing determinations that those EGUs are not subject-to-BART for NO_X, SO_2 and PM as proposed, based on the methodologies utilizing model plants and CALPUFF modeling as described in our proposed rule and BART Screening TSD.

The following sources are determined to be BART-eligible, but not subject-to-BART:

Table 2. Sources Determined to Be BART-Eligible But Not Subject-to-BART for NO_x, SO_2, and PM

Facility	Units
Barney M. Davis (Talen/Topaz)	1
Cedar Bayou (NRG)	CBY1 & CBY2
Dansby (City of Bryan)	1

Decker Creek (Austin Energy)	1 & 2
Greens Bayou (NRG)	5
Handley (Exelon)	3, 4 & 5
Jones (Xcel)	151B & 152B
Knox Lee (AEP)	5
Lake Hubbard (Luminant)	1 & 2
Lewis Creek (Entergy)	1 & 2
Nichols Station (Xcel)	143B
Plant X (Xcel)	4
Powerlane (City of Greenville)	ST1, ST2 & ST3
R W Miller (Brazos Elec. Coop)	1, 2 & 3
Sabine (Entergy)	2, 3, 4 & 5
Sim Gideon (LCRA)	1, 2 & 3
Spencer (City of Garland)	4 & 5
Trinidad (Luminant)	6
Ty Cooke (City of Lubbock)	1 & 2
V H Braunig (CPS Energy)	1, 2 & 3

3. SO_2 BART

The BART alternative will achieve SO_2 emission levels that are functionally equivalent to those projected for Texas' participation in the original CSAPR program. The BART alternative applies the CSAPR allowance allocations for SO_2 to all BART-eligible coal-fired EGUs, several additional coal-fired EGUs, and several BART-eligible gas-fired and gas/fuel oil-fired EGUs. In addition to being a sufficient alternative to BART, it secures reductions consistent with visibility transport requirements and is part of the long-term strategy to meet the reasonable progress requirements of the Regional Haze Rule.

The combination of the source coverage for this program, the total allocations for EGUs covered by the program, and recent and foreseeable emissions from EGUs not covered by the program will result in future EGU emissions in Texas that are similar to the SO_2 emission levels forecast in the 2012 better-than-BART demonstration for Texas EGU emissions assuming

CSAPR participation. In line with the comment from the TCEQ/PUC, we are finalizing a BART alternative that will encompass the SO_2 BART requirements for coal-fired EGUs and a number of gas- and gas/fuel oil-fired EGUs under a program that will include the sources in the following table. See Section V.B for a discussion on identification of participating sources.

Table 3. Texas EGUs Subject to the FIP SO_2 Trading Program

Owner/Operator	Units	BART-Eligible
AEP	Welsh Power Plant Unit 1	Yes
	Welsh Power Plant Unit 2	Yes
	Welsh Power Plant Unit 3	No
	H W Pirkey Power Plant Unit 1	No
	Wilkes Unit 1*	Yes
	Wilkes Unit 2*	Yes
	Wilkes Unit 3*	Yes
CPS Energy	JT Deely Unit 1	Yes
	JT Deely Unit 2	Yes
	Sommers Unit 1*	Yes
	Sommers Unit 2*	Yes
Dynegy	Coleto Creek Unit 1	Yes
LCRA	Fayette / Sam Seymour Unit 1	Yes
	Fayette / Sam Seymour Unit 2	Yes
Luminant	Big Brown Unit 1	Yes
	Big Brown Unit 2	Yes
	Martin Lake Unit 1	Yes
	Martin Lake Unit 2	Yes
	Martin Lake Unit 3	Yes
	Monticello Unit 1	Yes
	Monticello Unit 2	Yes
	Monticello Unit 3	Yes
	Sandow Unit 4	No
	Stryker ST2*	Yes
	Graham Unit 2*	Yes
NRG	Limestone Unit 1	No
	Limestone Unit 2	No

	WA Parish Unit WAP4*	Yes
	WA Parish Unit WAP5	Yes
	WA Parish Unit WAP6	Yes
	WA Parish Unit WAP7	No
Xcel	Tolk Station Unit 171B	No
	Tolk Station Unit 172B	No
	Harrington Unit 061B	Yes
	Harrington Unit 062B	Yes
	Harrington Unit 063B	No
El Paso Electric	Newman Unit 2*	Yes
	Newman Unit 3*	Yes
	Newman Unit 4*	Yes

* Gas-fired or gas/fuel oil-fired units

This BART alternative includes all BART-eligible coal-fired units in Texas, additional coal-fired EGUs, and some additional BART-eligible gas and gas/fuel oil-fired units. Moreover, we believe that the differences in source coverage between CSAPR and this BART alternative are either not significant or, in fact, work to demonstrate the relative stringency of the BART alternative as compared to CSAPR (See Section V of this notice for detailed information). This relative stringency can be understood in reference to the following points:

A. Covered sources under the BART alternative in this FIP represent 89%[41] of all SO_2 emissions from all Texas EGUs in 2016, and approximately 85% of CSAPR allocations for existing units in Texas.

B. The remaining 11 % (100 minus 89) of 2016 emissions from sources not covered by the BART alternative come from gas units that rarely burn fuel oil or coal-fired units that on

[41] In 2016, 218,291 tons of SO_2 were emitted from sources included in the program and 27,446 tons from other EGUs (11.1%).

average are better controlled for SO_2 than the covered sources and generally are less relevant to visibility impairment. (A fuller discussion of this point is provided in Section V of this notice.) As such, any shifting of generation to non-covered sources, as might occur if a covered source reduces its operation in order to remain within its SO_2 emissions allowance allocation, would result in less emissions to generate the same amount of electricity.

C. Furthermore, the non-inclusion of a large number of gas-fired units that rarely burn fuel oil reduces the amount of available allowances for units that would typically and collectively be expected to use only a fraction of CSAPR emissions allowances. Many of these sources typically emit at levels much lower than their allocation level. Sources not participating in the program may choose to opt in, thereby increasing the number of available allowances. This will serve to make the program more closely resemble CSAPR.

D. The BART alternative does not allow purchasing of allowances from out-of-state sources. Emission projections under CAIR and CSAPR showed that Texas sources were anticipated to purchase allowances from out-of-state sources.[42]

Based on these points, and borrowing to the greatest extent possible from the rules and program design of CSAPR, but applying them for Texas only, we are proceeding with the commenters', including the State of Texas', suggested consideration for SO_2 BART coverage for EGUs by means of a BART alternative under an intrastate trading program. As with any FIP, we

[42] See CAIR 2018 emission projections of approximately 350,000 tons SO_2 emitted from Texas EGUs compared to CAIR budget for Texas of 225,000 tons. See section 10 of the 2009 Texas Regional Haze SIP.

also would welcome Texas submitting a future SIP, as discussed in the MOA, that meets the Regional Haze Rule and the Act's requirements so as to enable future withdrawal of this FIP-based BART alternative.[43]

In 2014 we had originally proposed that CSAPR would satisfy the SO_2 BART requirement for Texas EGUs.[44] Although we never finalized that proposal, functionally, the final decision relies on substantially the same technical elements. In contrast to the 2014 proposal, however, we are not finalizing this SO_2 BART alternative as meeting the terms of 40 CFR 51.308(e)(4), as amended, because that regulatory provision, by its terms, provides BART coverage for pollutants covered by the CSAPR trading program in the State but on September 21, 2017, EPA finalized its proposed action to remove Texas from the CSAPR SO_2 trading program.[45] Instead we are relying on the BART alternative option provided under 40 CFR 51.308(e)(2). The BART alternative being finalized today is supported by our determination that the clear weight of the evidence is that the trading program achieves greater reasonable progress than BART. The BART alternative is designed to achieve SO_2 emission levels from Texas sources similar to the SO_2 emission levels that would have been achieved under CSAPR. By a quantitative and qualitative assessment of the operation of the BART alternative, we are able to conclude that emission levels will be on average no greater than the emission levels from Texas EGUs that would have been realized from the SO_2 trading program under CSAPR. (See Section V of this notice for detailed information). Accordingly, by the measure of CSAPR better than

[43] See Memorandum of Agreement Between the Texas Commission on Environmental Quality and the Environmental Protection Agency Regarding a State Implementation Plan to Address Certain Regional Haze and Interstate Visibility Transport Requirements Pursuant to Sections 110 and 169A of the Clean Air Act, signed August 14, 2017.

[44] 79 FR 74817, 74823 (December 16, 2014) ("We propose to replace Texas' reliance on CAIR to satisfy the BART requirement for EGUs with reliance on CSAPR."). This part of the 2014 proposal was not finalized in the action taken on January 5, 2016, that has since been remanded by the Fifth Circuit Court of Appeals. 81 FR 295.

[45] See final action signed September 21, 2017 available at *regulations.gov* in Docket No. EPA-HQ-OAR-2016-0598

BART, the SO_2 BART FIP for Texas' BART-eligible EGUs participating in the trading program will achieve greater reasonable progress than BART with respect to SO_2. BART-eligible EGUs not participating in the program are demonstrated to not cause or contribute to visibility impairment, and we are finalizing our determination in this action that these units are not subject to BART.

The Regional Haze Rule at 40 CFR 51.308(e)(2)(iii) requires that the emission reductions from BART alternatives occur "during the period of the first long-term strategy for regional haze." The SO_2 BART alternative that EPA is finalizing here will be implemented beginning in January 2019, and thus emission reductions needed to meet the allowance allocations must take place by the end of 2019. For the purpose of evaluating Texas's BART alternative, the end of the first planning period of the first long-term strategy for Texas is 2021. This is a result of recent changes to the regional haze regulation, revising the requirement for states to submit revisions to their long-term strategy from 2018 to 2021.[46] Therefore, the emission reductions from the Texas SO_2 trading program will be realized prior to that date and within the period of Texas' first long-term strategy for regional haze.

In promulgating the regulatory terms and rules for implementing the BART alternative, we are mindful of the minimally required elements for a BART alternative emissions trading program that are specified in the provisions of 40 CFR 51.308(e)(2)(vi)(A)-(L). In general, these types of provisions are foundational, in a generic sense, to the establishment of allowance markets. CSAPR is a prominent example of such an allowance market, and by transferring and generally incorporating program rules and terms from the well-tested provisions of CSAPR we have ensured that the BART alternative will conform in detail and coverage to the breadth of

[46] 82 FR 3078 (Jan. 10, 2017).

provisions that are needed for an emissions trading program covered by a cap (See Section V of this notice for additional discussion). To the extent that Texas would submit a future SIP revision under its SIP authority to implement SO_2 BART or an SO_2 BART alternative for its EGUs as described in the MOA to meet the Regional Haze Rule and CAA requirements, it may look to the provisions promulgated under FIP authority or it may examine its flexibilities and the extent of its discretion regarding essential provisions detailed at 40 CFR 51.308(e)(2)(vi).

4. PM BART

In our January 2017 proposal, we proposed to disapprove Texas' technical evaluation and determination that PM BART emission limits are not required for any of Texas' EGUs. The Texas Regional Haze SIP included a pollutant-specific screening analysis for PM to demonstrate that Texas EGUs were not subject to BART for PM. This approach was consistent with a 2006 guidance document[47] in which the EPA stated that pollutant-specific screening can be appropriate where a state is relying on a BART alternative to address both NO_X and SO_2 BART. Because we proposed to address SO_2 BART on a source-specific basis, however, Texas' pollutant-specific screening was not appropriate and we proposed source-specific PM BART emission limits consistent with existing practices and controls. In this final action, we are not finalizing source-specific SO_2 BART determinations. Instead, for the majority of Texas' BART-eligible EGUs, we are relying on BART alternatives for both SO_2 and NO_X emissions. Therefore, we now conclude that Texas' pollutant-specific screening analysis was appropriate. All of the BART-eligible sources participating in the intrastate trading program have visibility impacts

[47] *See* discussion in Memorandum from Joseph Paisie to Kay Prince, "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations," July 19, 2006.

from PM alone below the subject-to-BART threshold of 0.5 deciviews (dv).[48] Furthermore, the BART-eligible sources not participating in the intrastate trading program screened out of BART for all visibility impairing pollutants. As such, we are approving the portion of the Texas Regional Haze SIP that determined that PM BART emission limits are not required for any Texas EGUs.

As we explained in the January 2017 proposal, the Texas Regional Haze SIP did not evaluate PM impacts from all BART-eligible EGUs. We have evaluated and determined this omission does not affect Texas' conclusion that no BART-eligible EGUs should be subject-to-BART for PM emissions. In our proposal, we identified several facilities as BART-eligible that Texas did not identify as BART eligible in the Texas Regional Haze SIP. Specifically, we identified the following additional BART-eligible sources: Coleto Creek Unit 1 (Dynegy), Dansby Unit 1 (City of Bryan), Greens Bayou Unit 5 (NRG), Handley Units 3,4, and 5 (Excelon), Lake Hubbard Units 1 and 2 (Luminant), Plant X Unit 4 (Xcel), Powerlane Units ST1, ST2, and ST3 (City of Greenville), R W Miller Units 1, 2, and 3 (Brazos Elec.), Spencer Units 4 and 5 (City of Garland), and Stryker Creek Unit ST2 (Luminant). In our proposal, we used CALPUFF modeling and a model-plant analysis and found that all of these facilities except Coleto Creek and Stryker Creek had impacts from NOx, SO_2 and PM below the BART screening level.[49] CALPUFF modeling showed that Stryker Creek Unit ST2 had a visibility impact of 0.786 dv from NOx, SO_2 and PM. However, Stryker Creek Unit ST2 is now covered by a BART alternative for NO_X and SO_2, so we evaluated the visibility impact of Stryker Creek Unit ST2's

[48] Stryker Creek is covered by CSAPR for NOx and by the SO_2 trading program but was not included in the 2009 Regional Haze SIP. How Stryker Creek is screened out for PM is discussed below.
[49] EPA's Proposal screened out Dansby, Greens Bayou, Handley, Lake Hubbard, Plant X, Powerlane, R W Miller, and Spencer using CALPUFF direct modeling and Model Plants.

PM emissions alone. The CALPUFF modeling files and spreadsheets included in our proposal indicate that light extinction from PM (PM_{Fine} and PM_{Coarse}) is less than 1% of total light extinction at all Class I areas. Therefore, because the visibility impact of PM emissions from Stryker Creek Unit ST2 would be a small fraction of 0.786 dv (roughly 1%), the source is not subject to BART for PM under EPA's 2006 guidance.

We also evaluated the potential visibility impact of PM emissions from Coleto Creek Unit 1 using the CAMx modeling that Texas used for PM BART screening of its EGU sources in its SIP.[50] Specifically, we evaluated the modeling results for two facilities (LCRA Fayette and Sommers Deely) with stack parameters similar to Coleto Creek's, but which are located closer to Class I Areas than Coleto Creek. Texas grouped the LCRA Fayette Facility in Group 2 of their PM screening modeling along with other sources and found that their maximum aggregate impacts at all Class I areas were less than 0.25 deciviews (dv). Texas also explicitly modeled the City Public Service Sommers Deely Facility's PM impacts. Maximum impacts at all Class I areas from Sommers Deely were less than 0.32 dv. To extend these model results to Coleto Creek, we used the Q/D ratio where Q is the maximum annual PM emissions[51] and D is the distance to the nearest receptor of a Class I area. If the Q/D ratio of Coleto Creek is smaller than the ratios for the two modeling results (Fayette and Sommers Deely) then Coleto Creek impacts can be estimated as less than the impacts of these source(s) and thus be screened out. We evaluated the closest Class I Areas (Big Bend, Guadalupe Mountains, Carlsbad, Wichita Mountains, and Caney Creek)

[50] Environ Report – "Final Report Screening Analysis of Potential BART-Eligible Sources in Texas", September 27, 2006; "Addendum 1 – BART Exemption Screening Analysis", Draft December 6, 2006; and "BARTmodelingparameters V2.csv".

[51] This is calculated by using the maximum daily PM_{10} daily emission rate, adding the maximum daily $PM_{2.5}$ emission rate and then calculating the total emissions in tons per year if this max daily rate happened every day.

and the Q/D ratios were: Coleto Creek (0.59-0.86), Fayette (4.25-6.1), and Sommers Deely (6.0-10.05).[52] The Q/D ratio for Fayette is 6 to 8 times larger than for Coleto Creek, while the Q/D ratio for Sommers Deely is 9 to 11.6 times higher than for Coleto Creek. Therefore, if we were to model the PM impacts from Coleto Creek, they would be an order of magnitude smaller than the impacts from these facilities, which are well below the threshold of 0.5 dv. Therefore, Coleto Creek is not subject to BART for PM emissions.

In finalizing an approval of Texas' determinations regarding PM BART, we offer one additional note. We originally proposed to approve Texas' screening approach in 2014,[53] and our final action today essentially conforms to our technical evaluation in that proposal.

5. NO_X BART

We are finalizing our proposed determination that Texas EGUs' continued participation in the CSAPR program for interstate transport for ozone will serve as a BART alternative for NO_X for EGUs in the State of Texas. Our action to address NO_X BART for EGUs as it applies to Texas is based on two other recent rulemakings concerning CSAPR. The first is the rulemaking to update CSAPR to address interstate transport of ozone pollution with respect to the 2008 ozone NAAQS, which established a new ozone season budget for NO_X emissions in Texas.[54] The second is the determination that CSAPR continues to be a better than BART alternative, on a pollutant specific basis, for states that participate in the CSAPR program as it now exists.[55] Because our FIP relies on CSAPR as a BART alternative for NO_X for Texas EGUs, we are not

[52] *See* 'Coleto_Creek_Screen_analysis.xlsx'
[53] *See* 79 FR 74817, 74848 (Dec. 16, 2014).
[54] 81 FR 74504 (Oct. 16, 2016).
[55] See final action signed September 21, 2017 available at *regulations.gov* in Docket No. EPA-HQ-OAR-2016-0598

required in this action to promulgate source-specific NO_X BART determinations for those sources.

We note that Texas may opt to use its SIP planning authority, as was noted in its 2009 Regional Haze SIP in a similar context, to address the NO_X BART requirement for EGUs without relying on CSAPR. If Texas instead wishes to rely upon the CSAPR program to address the NO_X BART requirement, it may submit a SIP revision to establish its reliance on the program to satisfy the requirement for NO_X BART for EGUs. By using the SIP pathway, Texas would be exercising the primary responsibility for air pollution control that is embodied in the Act. *See* CAA section 101(a)(3). Recognizing that the 2009 Regional Haze SIP did not, by its terms, provide an approvable means to address the requirement, however, we are now required to exercise our FIP authority to address it.[56] We are therefore finalizing the determination as proposed.

B. Interstate Transport of Pollutants that Affect Visibility

We are finalizing our proposal to disapprove Texas' SIP revisions addressing interstate visibility transport under CAA section 110(a)(2)(D)(i)(II) for six NAAQS. As explained further in our proposal, Texas' infrastructure SIPs for these six NAAQS relied on the 2009 Regional Haze SIP, including its reliance on CAIR as an alternative to EGU BART for SO_2 and NO_X to meet the interstate visibility transport requirements.[57] We are finalizing a FIP to fully address

[56] As explained in our proposal, our ongoing authority and obligation to address the NOx BART requirement for Texas EGUs under CAA section 110(c) traces to EPA's limited disapproval of the 2009 Texas Regional Haze SIP in 2012 due to the State's reliance on the remanded and replaced CAIR as an alternative to NO_X BART. *See also EME Homer City Generation*, *L.P. v. EPA*, 795 F.3d 118, 133-34 (D.C. Cir. 2015) holding that SIPs based on CAIR were unapprovable to fulfill good neighbor obligations.

[57] 82 FR 912, 916 (Jan. 4, 2017).

Texas' interstate visibility transport obligations for the following six NAAQS: (1) 1997 8-hour ozone, (2) 1997 $PM_{2.5}$ (annual and 24 hour), (3) 2006 $PM_{2.5}$ (24-hour), (4) 2008 8-hour ozone, (5) 2010 1-hour NO_2 and (6) 2010 1-hour SO_2.

An EPA guidance document (2013 Guidance) on infrastructure SIP elements states that CAA section 110(a)(2)(D)(i)(II)'s interstate visibility transport requirements can be satisfied by approved SIP provisions that the EPA has found to adequately address a state's contribution to visibility impairment in other states.[58] The EPA interprets interstate visibility transport to be pollutant-specific, such that the infrastructure SIP submission need only address the potential for interference with protection of visibility caused by the pollutant (including precursors) to which the new or revised NAAQS applies.[59] The 2013 Guidance lays out two ways in which a state's infrastructure SIP submittal may satisfy interstate visibility transport. One way is through a state's confirmation in its infrastructure SIP submittal that it has an EPA approved regional haze SIP in place. In the absence of a fully approved regional haze SIP, a demonstration that emissions within a state's jurisdiction do not interfere with other states' plans to protect visibility meets this requirement. Such a demonstration should point to measures that limit visibility-impairing pollutants and ensure that the resulting reductions conform with any mutually agreed emission reductions under the relevant regional haze regional planning organization (RPO) process.[60]

To develop its 2009 Regional Haze SIP, TCEQ worked through its RPO, the Central Regional Air Planning Association (CENRAP), to develop strategies to address regional haze,

[58] *See* "Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and (2)" included in the docket for this action.
[59] *See Id.*, at 33.
[60] *See Id.*, at 34, and 76 FR 22036 (April 20, 2011) containing EPA's approval of the visibility requirement of 110(a)(2)(D)(i)(II) based on a demonstration by Colorado that did not rely on the Colorado Regional Haze SIP.

which at that time were based on emissions reductions from CAIR. To help states in establishing reasonable progress goals for improving visibility in Class I areas, the CENRAP modeled future visibility conditions based on the mutually agreed emissions reductions from each state. The CENRAP states then relied on this modeling in setting their respective reasonable progress goals.

This FIP is adequate to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states because the BART FIP emission reductions are consistent with the level of emissions reductions relied upon by other states during consultation. The 2009 Texas Regional Haze SIP relied on CAIR to meet SO_2 and NOx BART requirements. Under CAIR, Texas EGU sources were projected to emit approximately 350,000 tpy of SO_2. As discussed elsewhere, Texas EGU emissions for sources covered by the trading program will be constrained by the number of available allowances. Average annual emissions for the covered sources will be less than or equal to 248,393 tons with some year to year variability constrained by the number of banked allowances and number of allowances that can be allocated in a control period from the supplemental pool. Sources not covered by the program emitted less than 27,500 tons of SO_2 in 2016 and are not projected to significantly increase from this level. Any new units would be required to be well controlled and similar to the existing units not covered by the program, they would not significantly increase total emissions of SO_2. Additionally, this FIP relies on CSAPR as an alternative to EGU BART for NO_X, which exceeds the emissions reductions relied upon by other states during consultation. As such, this BART FIP is sufficient to address the interstate visibility transport requirement under CAA section 110(a)(2)(D)(i)(II) for the six NAAQS.

C. Reasonable Progress

This final action is part of the long-term strategy for Texas and will contribute to making reasonable progress toward natural visibility conditions at Texas' and downwind Class I areas. However, the EPA is not determining at this time that this final action fully resolves the EPA's outstanding obligations with respect to reasonable progress that resulted from the Fifth Circuit's remand of our reasonable progress FIP. We intend to take future action to address the Fifth Circuit's remand.

IV. Summary and Analysis of Major Issues Raised by Commenters

We received both written and oral comments at the public hearings we held in Austin. We also received comments by the internet and the mail. The full text of comments received from these commenters, except what was claimed as CBI, is included in the publicly posted docket associated with this action at www.regulations.gov. The CBI cannot be posted to www.regulations.gov, but is part of the record of this action. We reviewed all public comments that we received on the proposed action. Below we provide a summary of certain comments and our responses. First, we provide a summary of all of the relevant technical comments we received and our responses to these comments. We do not consider some of the technical comments as relevant to the final action. For these comments we provide a brief summary of the comments and a discussion as to why they are not relevant. Second, we provide a summary below of the more significant legal comments with a summary of our responses. All of the legal comments we received that are relevant to our final action are found in a separate document, titled the Legal Response To Comments (RTC) document. Therefore, if additional information is desired concerning how we addressed a particular legal comment, the reader should refer to the Legal RTC document. Third, we provide a summary of the more significant/relevant modeling related comments with a summary of our responses. The entirety of the modeling comments and our responses thereto are contained in a separate document titled the Modeling RTC document.

A. Comments on Relying on CSAPR for SO_2 BART or Developing an Intrastate SO_2 Trading Program

Comment: We received comments from TCEQ that our proposed SO_2 controls for the coal-fired power plants represents more control than is necessary to satisfy BART. The EPA should consider an alternate control approach for these BART-affected units using source or system caps. Because the CSAPR level of control is better than BART, the EPA should have considered an equivalent control level in its BART analysis. For example, a potential alternative is the concept of system-wide emission caps using CSAPR allocations. A SO_2 system-cap approach for BART would be based on establishing a cap on all the BART subject units under common ownership and control based on CSAPR allocations to those specific units. System-wide caps for these BART subject units based on CSAPR allocations would provide flexibility while actually being more stringent than CSAPR because the companies would not have the ability to trade allocations with non-BART facilities or with companies in other states. Furthermore, the EPA has approved system-cap approaches under the TCEQ's Chapter 117 rules for NO_X. If such an approach using CSAPR allocations or some other similar variation can be demonstrated to be more stringent than CSAPR itself, then the EPA's CSAPR-is-better-than-BART determination should satisfy some of the demonstration requirements for BART alternatives. Even if not based on CSAPR allocations, the EPA should consider a source-cap or system cap approach as an alternative to unit-by-unit rate-based standards. Source and system cap strategies achieve equivalent reductions by setting mass-based limits (e.g., ton per day) for a group of units derived from rate-based standards and baseline levels of activity for the units. In this context, the rate-based standards used to set the caps would be the emission rates determined to represent BART. These types of cap approaches allow companies to consider a broader range of alternative strategies. Under a FIP with only unit-by-unit rate-based limits, as proposed by EPA, such an alternative strategy would not be allowed and EPA would have to revise its FIP to allow the company to pursue the alternative. A similar approach using system-caps would provide additional flexibility for companies. If the EPA is averse to creating a system-cap trading program for a single state, an alternative would be to allow for a state system-cap trading program that would allow companies to trade between systems once the EPA has approved the state program.

We received a comment from American Electric Power (AEP) stating that in the proposed Texas BART FIP, EPA states that it encourages Texas to consider adopting SIP provisions that would allow EPA to fully approve the Regional Haze SIP with respect to Regional Haze and Interstate Visibility Transport. AEP also suggests that alternatively, Texas may also elect to satisfy its obligations by demonstrating an alternative. Although AEP views the most expeditious resolution for satisfying BART is finalization of CSAPR as a better-than-BART alternative, AEP would also welcome and support working with the State and EPA to develop a satisfactory BART compliance alternative. For example, AEP is open to consideration of a cap and trade program or other option for BART compliance. AEP is prepared to engage in such discussions as soon as possible.

We also received a comment from Luminant stating that the EPA can and should address BART for Texas, not through EPA-mandated controls on individual units but through one of several available BART alternatives that will ensure equivalent or greater benefits at far less costs, as demonstrated by EPA's own prior analyses of Texas EGUs' emissions. Among those available alternatives is EPA's original proposed BART plan for EGUs in Texas—reliance on Texas EGUs' participation in the CSAPR annual SO_2 and NO_X trading programs as BART compliance. Since CSAPR became effective in 2015, SO_2 emissions from Texas EGUs have declined substantially and are well below the levels that EPA previously determined are "better-than-BART." EPA itself calculated "major visibility improvements at Class I areas in and around Texas" from the CSAPR-for-BART alternative for Texas. The CSAPR-for-BART alternative remains the most expeditious and cost effective path for finalizing a BART solution for Texas EGUs. Indeed, EPA's only lawful path forward to finalize a BART FIP for Texas by the current September 9, 2017 deadline in EPA's consent decree with Sierra Club is to finalize a CSAPR-for-BART FIP for Texas EGUs, as EPA proposed to do in December 2014. That proposal was not withdrawn, remains a valid and defensible alternative, is supported by the record and prior EPA technical analyses, and has been fully vetted with substantial public review and comments.

Response: Due to these comments requesting a BART alternative in lieu of source-specific EGU BART, we are finalizing an intrastate SO_2 trading program as an alternative to source-by-source BART and to meet the interstate visibility transport requirements. This program will provide the commenters, and other owners of covered EGUs, with many of the benefits that they attributed to CSAPR. The premise in the comment that Texas EGUs are subject to CSAPR's SO_2 trading program is no longer true, given our recent action to remove Texas from that trading program.[61] Hence, we cannot take the commenter's recommended action of addressing SO_2 BART through reliance on CSAPR.

[61] See final action signed September 21, 2017 available at *regulations.gov* in Docket No. EPA-HQ-OAR-2016-0598

B. Comments on Source-Specific BART

Comment: We received a number of comments in favor or against our proposals regarding BART-eligibility status, subject-to-BART status, and source-specific BART technologies and emission limits. Some were general and some were very specific.

Response: Due to the comments we received requesting a BART alternative in lieu of source-specific BART determinations, we are finalizing an intrastate SO_2 trading program as an alternative to source-by-source BART and to meet the interstate visibility transport requirements. As a consequence, we believe that it is not necessary to respond to comments concerning the merits of the proposed source-specific BART technologies and emission limits. Comments related to BART-eligibility status and subject-to-BART status are addressed elsewhere in this notice.

C. Comments on EPA's Proposed SIP Disapprovals

Comment: The root of EPA's flawed proposal is EPA's departure from the cooperative federalism principles underlying the Clean Air Act. The State of Texas developed its regional haze SIP after years of work, technical analysis, and coordination with other States. For BART, Texas relied on the participation of Texas EGUs in CAIR and EPA's determination that CAIR was better-than-BART. EPA should have approved Texas's SIP at the time because it complied with all statutory requirements and was supported by EPA's own modeling. In no way does the Proposed Texas BART FIP—which starts over from scratch and creates an entirely new approach to BART for Texas EGUs—respect the State's primary role under the statute. At a minimum, to more closely align with the State of Texas's original choice to meet BART through a regional trading program, EPA should now finalize its prior proposal that CSAPR serve as a complete BART alternative for Texas EGUs.

Response: Our action in 2012 to disapprove Texas' 2009 SIP submission due to its reliance on CAIR is not the subject of this rulemaking and we do not address here the comment opposing that final action. We agree that CSAPR continues to be available on a pollutant-specific basis as a BART alternative for participating states for those pollutants subject to trading by CSAPR program participation; hence, we are finalizing a determination that CSAPR is better than BART for NO_X at Texas EGUs. However, the premise in the comment that Texas EGUs are subject to CSAPR's SO_2 trading program is no longer true, given our recent action to remove them from that trading program.[62] Hence, we cannot take the specific action recommended in this comment. Due to these comments requesting a BART alternative in lieu of source-specific EGU BART determinations, we are, however, finalizing a SO_2 trading program as an alternative to source-by-source BART and as meeting the interstate visibility requirements.

D. Legal Comments

We received comments addressing EPA's authority to promulgate a Federal Implementation Plan (FIP), the use of CSAPR as a better-than-BART alternative, cooperative federalism, deference to the State, the new Administration's policies, Executive Orders, and litigation. These comments, and the response to comments, can be found in the document titled Legal RTC in the docket for this action. Below is a summary of some of the more significant

[62] See final action signed September 21, 2017 available at *regulations.gov* in Docket No. EPA-HQ-OAR-2016-0598

comments we received. For a detailed review of all legal comments and responses, we refer the reader to this separate document.

1. EPA's Obligation and Authority to Promulgate a FIP

Comment: Texas' and industry's challenge to CSAPR does not relieve EPA of its mandatory duty to issue a source-specific BART FIP for Texas. Although EPA would have permitted Texas to rely on CSAPR's modest cap-and-trade program to avoid source-specific BART controls, Texas, Luminant, AEP, and Southwestern Public Service Company all chose to challenge CSAPR. They were ultimately successful in defeating EPA's inclusion of Texas in the program for SO_2 and ozone-season NO_X. Ever since the D.C. Circuit remanded the Texas NO_X and SO_2 budgets to EPA in July 2015, Texas has been on notice that source-specific BART could well be necessary to meet its BART obligations. Yet Texas has not put forward either a new interstate transport SIP to replace CSAPR or a new BART SIP to address the Regional Haze Rule.

Response: We agree that we have a mandatory duty to address the BART requirements for Texas EGUs but we do not agree that we must address these requirements through a FIP establishing source specific BART limits. We understand the comment to be referencing the court action, *EME Homer City Generation v. EPA*, 795 F.3d 118 (D.C. Cir., July 28, 2015). At all times since the original submission of the 2009 Regional Haze SIP, Texas has been entitled to submit updated or new SIP revisions to address BART or interstate transport. A State is also entitled to submit a SIP that may be approved to replace a FIP after a FIP's promulgation. When and whether Texas has been "on notice" regarding a potential need for source-specific BART is not material to the present need to address the EGU BART requirements through either a SIP or FIP. We do note that the 2009 Regional Haze SIP stated, "The TCEQ will take appropriate action if CAIR is not replaced with a system that the US EPA considers to be equivalent to BART." See 2009 SIP at 9-1. The 2009 SIP further acknowledged, "Some EGUs may become subject to BART pending resolution of the CAIR at the federal level." See 2009 SIP at 9-17. As circumstances now apply to Texas (and, as this comment suggests, may have been earlier projected), the State can take appropriate action to develop a SIP to address the EGU BART and interstate visibility transport requirements. The TCEQ and EPA recently signed a MOA to work together to develop a SIP revision addressing interstate visibility transport requirements and BART requirements for EGUs with a BART alternative trading program starting from CSAPR.[63] However, without such a SIP, the Clean Air Act requires a promulgation of a FIP to address the outstanding BART and interstate transport requirements.

Comment: Texas's decision to not meet the BART requirements for its EGUs through voluntary participation in CSAPR does not relieve EPA of its mandatory duty to issue a source-specific BART FIP for Texas. Even if Texas were willing to voluntarily incorporate EPA's invalidated CSAPR emission budgets into its SIP, the state cannot simply opt in and avoid source-specific BART. Because Texas cannot reverse course and adopt emissions budgets that it demonstrated were unnecessary, as a matter of law, and because the agency cannot achieve "all"

[63] See Memorandum of Agreement Between the Texas Commission on Environmental Quality and the Environmental Protection Agency Regarding a State Implementation Plan to Address Certain Regional Haze and Interstate Visibility Transport Requirements Pursuant to Sections 110 and 169A of the Clean Air Act, Signed August 14, 2017.

of the CSAPR reductions by 2018 (the end of the first planning period), it cannot voluntarily adopt CSAPR.

Response: We agree that we have a mandatory duty to address the BART requirement for Texas EGUs, but we do not agree that we must address it through a source-specific BART FIP. We understand this comment to refer to a hypothetical scenario based on the development and submission of a SIP by Texas providing for voluntary participation in CSAPR as a means of addressing the SO_2 and/or NO_X BART requirements for Texas EGUs. The possibility of such an option was detailed in a June 27, 2016 memorandum entitled, "The U.S. Environmental Protection Agency's Plan for Responding to the Remand of the Cross-State Air Pollution Rule Phase 2 SO_2 Budgets for Alabama, Georgia, South Carolina and Texas." That memorandum was provided and available to Texas and other states. Several other states have pursued this option, but Texas has not, and it is not within the scope of our proposal. We are not opining on the operation of state law or otherwise responding to this comment. We address the issue of whether emission reductions from a BART alternative must be achieved by 2018 in our response to another comment.

Comment: EPA withdrawal of Texas from CSAPR does not relieve EPA of its mandatory duty to issue a source-specific BART FIP for Texas. After having given Texas four months' notice of its intent to fully withdraw the state from the CSAPR program, and made clear the implication that there would no longer be any doubt that Texas sources would need to comply with source-specific BART obligations, EPA formally issued its proposal to withdraw its federal plan to include Texas in the CSAPR emissions trading program one month before issuing the

BART proposal. 81 Fed. Reg. 78,954 (Nov. 10, 2016). EPA again made clear the situation: "[I]f and when this [CSAPR withdrawal] proposal is finalized, Texas will no longer be eligible to rely on CSAPR participation as an alternative to certain regional haze obligations including the determination and application of source-specific SO_2 BART. Any such remaining obligations are not addressed in this proposed action and would be addressed through other state implementation plan (SIP) or FIP actions as appropriate." *Id.* at 78,956. EPA has informed the U.S. District Court for the District of Columbia that it intends to finalize this proposal by October 31, 2017.

After challenging the state's inclusion in CSAPR for years, industry has done an about face in response to EPA's Texas BART Proposal and now opposes EPA's withdrawal of Texas from CSAPR. But EPA has gone on record that the agency does not currently have an analytical basis to support new CSAPR budgets for Texas. As EPA has noted, there was no such thing as a legally compliant CSAPR budget for Texas following the remand. Texas has had many years to submit a state SIP equivalent to CSAPR or other BART alternative to avoid source-specific BART, but Texas has taken no action to address its contribution to interstate pollution or regional haze.

Response: We agree that we have a mandatory duty to address the BART requirement for Texas EGUs, but we do not agree that we must address it through a source-specific BART FIP. We also have a mandatory duty to address the interstate visibility transport requirements.

Comment: We have strongly opposed the CSAPR-Better-than-BART rule since its inception. It is unlawful and unsupported by the scientific record. Legal challenges to EPA's rule which purports to authorize reliance on CSAPR to satisfy BART are currently pending in the

D.C. Circuit Court of Appeals. Until the D.C. Circuit rules on the validity of the CSAPR-Better-than-BART rule, neither EPA nor Texas should assume that CSAPR is an appropriate substitute for BART.

Response: The legal and technical determinations of the CSAPR-Better-than-BART rule are subject to judicial review under existing challenges and a separate administrative record, as indicated by the comment. Any challenges raised with regard to the present rulemaking and outside that litigation may be time-barred or directed to the wrong forum. As such, we do not believe that the incorporation of arguments from a brief filed with the D.C. Circuit concerning a separate regulatory determination warrants responses here, in this rulemaking, and that to offer responses here would suggest some basis for collateral, time-barred arguments that are out of the scope of this action.

Comment: In addition to the legal uncertainty surrounding the national CSAPR-Better-than-BART rule, it is too late for Texas to rely on a BART alternative like CSAPR or any other program. Under EPA's Regional Haze Rule, any BART *alternative* must include a "requirement that all necessary emission reductions take place during the period of the first long-term strategy for regional haze"—*i.e.*, no later than 2018. There are no plans in place, or even in development, for any federal or state program that would ensure the necessary reductions take place by the end of the first planning period in 2018.

With the exception of a BART alternative approved for the Navajo Generating Station, which relied on the Tribal Authority Rule to provide additional flexibility, EPA has never proposed or approved a BART alternative that would allow the necessary emission reductions to be delayed past 2018. In *Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016), Texas and industry persuaded the Fifth Circuit of a likelihood that EPA could not require controls beyond the first planning period for reasonable progress. While neither the statute nor regulation precludes emission reductions relative to *reasonable progress requirements* to occur beyond the planning period deadline, the *BART alternative requirements* contain a provision directly on point. Accordingly, emission reductions under a BART alternative must be implemented by the end of the first planning period.

Response: The Regional Haze Rule at 40 CFR 51.308(e)(2)(iii) requires that the emission reductions from BART alternatives occur "during the period of the first long-term strategy for regional haze." The SO_2 BART alternative that EPA is finalizing here will be implemented beginning in January 2019, and thus emission reductions needed to meet the allowance allocations must take place by the end of 2019. For the purpose of evaluating Texas's BART alternative, the end of the first planning period of the first long-term strategy for Texas is 2021. This is a result of recent changes to the regional haze regulation, revising the requirement for states to submit revisions to their long-term strategy from 2018 to 2021.[64] Therefore, the emission reductions from the Texas SO_2 trading program will be realized prior to that date and within the period of Texas' first long-term strategy for regional haze. Moreover, we expect that source owners in 2018 will already be taking steps, including appropriate source-level compliance planning (e.g., purchase contracts for coal), to be ready for the compliance year beginning on January 1, 2019. Adding to this, the State has already experienced reductions in SO_2 emissions in response to market conditions and, to some extent, periods of compliance with

[64] 82 FR 3078 (Jan. 10, 2017).

CSAPR, including its allocations for SO_2, when those measures were in effect or otherwise part of source owner planning considerations.

We note that the BART alternative is projected to be implemented before any of the earlier-proposed compliance dates for source-specific SO_2 BART for coal-fired units.

The last year for which Texas EGUs must meet CSAPR requirements for SO_2 is 2016. We considered and decided not to make the Texas SO_2 trading program effective for 2017 because that would be unreasonably short notice to the affected EGUs in light of the late date in 2017 on which this action will become effective. We considered and decided not to make the program effective for 2018 because that also would be unreasonably short notice given that affected EGU owners should be allowed more than a few months to determine their strategy for compliance with the program in light of it having some features that are different from the CSAPR trading program they have been operating under until recently, for example the fact that they will no longer be able to purchase and use allowances from out-of-state EGUs.

Comment: Adopting an emissions trading program for Texas that allows anywhere close to the tonnage of SO_2 permitted by the emissions caps in CSAPR would also fail to meet the substantive requirements for a BART alternative. While the D.C. Circuit is considering whether CSAPR meets these substantive requirements in the CSAPR-Better-than-BART litigation, Texas's situation is unique in that EPA has actually completed a source-specific BART proposal that can be directly compared with the CSAPR program. Thus, even if the CSAPR-Better-than-BART rule is upheld as a national rule that EPA has the option of relying upon in certain states, and even if Texas were to join CSAPR or voluntarily adopt its budgets, it would be arbitrary for EPA to rely on CSAPR as a BART alternative without actually comparing the CSAPR or

CSAPR-like program with its BART proposal. When comparing the two head-to-head, it is obvious as a practical matter that allowing Texas's coal-fired power fleet to essentially continue emitting the same levels of SO_2 as the status quo is not going to achieve equivalent visibility gains as the BART proposal would. As detailed in "EPA's Fact Sheet for the Open House on EPA's Clean Air Plan Proposal for Texas Regional Haze", the proposed BART limits are expected to reduce emissions of SO_2 from 16 EGUs and would cut emissions from approximately 89 to 98 percent – a reduction of over 194,000 tons of SO_2 every year.

To satisfy the requirements for a BART "alternative," an emissions trading program must make a technical demonstration that the trading program "will achieve greater reasonable progress [towards natural visibility] than would have resulted from the installation and operation of BART at all sources subject to BART." *Id.* § 51.308(e)(2)(i). Under EPA's regulations, if the distribution of emissions is different under an alternative program, a state "must conduct dispersion modeling" to determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling only demonstrates "greater reasonable progress" if both of the following two criteria are met: (i) Visibility does not decline in any Class I area, and (ii) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas. *Id.* § 51.308(e)(3).

Response: The comment addresses the approvability of a hypothetical SIP offered to meet the requirements of 40 CFR § 51.308(e)(2). First, we do not agree with the premise of the comment that merely proposed determinations of BART in the context of a possible FIP set a stringency threshold for a demonstration set forth in a hypothetical SIP. Proposed determinations are only proposals and the facts put forth to support those proposals are themselves subject to correction via public comment and new information. Second, we also do not agree with any extension of the commenter's assertion to a FIP. While the comment does not address all the pertinent requirements for a BART alternative, we have done so elsewhere in this notice. For example, as allowed by the requirements for a BART alternative in 51.308(e)(2)(i)(C), we are declining to conduct the analysis that would include making determinations of BART for each source subject to BART and we are instead exercising the exception allowed when the alternative measure "has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States)."[65] Third, we disagree that 51.308(e)(3) applies to this action. Rather, we find justification for the BART alternative under the "clear weight of the evidence" that the trading program will provide greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources. This means of validating a BART alternative, described by one Court as the "catch-all," is permitted by 40 CFR 51.308(e)(2)(i)(E). We are allowed but not required to validate the BART alternative under the test set out in 40 CFR 51.308(e)(3). Although we are not applying that test here, we believe this intrastate trading program meets the intent of (e)(3). When promulgating the 2012 CSAPR-Better-than-BART rule, the EPA relied on an analysis showing that CSAPR would result in greater reasonable progress than BART under the test in 40 CFR 51.308(e)(3). In this action we are relying, in part, on that demonstration to show that the clear weight of evidence demonstrates that the SO2 Trading Program will provide for greater reasonable progress than BART in Texas. This is based on a showing that the emissions in Texas under the BART alternative will be on average no

[65] See 40 CFR 51.308(e)(2)(i)(C).

greater than the emission levels from Texas EGUs that was forecast in the demonstration for Texas EGU emissions assuming CSAPR participation.

2. Statutory or Regulatory Text

Comment: A state should be able to independently rely on EPA's CSAPR-is-better-than-BART determination if the state can demonstrate that a state-only program for EGUs is more stringent than CSAPR. While the TCEQ has not proposed any action to implement a Texas-only program for EGUs based in some way on CSAPR as a means of satisfying BART, and these comments in no way represent a commitment to propose such an action, the TCEQ should be able to rely on the EPA's CSAPR-is-better-than-BART determination to satisfy certain aspects of the BART alternative provisions in 40 CFR Part 51, §51.308(e)(2) if such a program can be demonstrated to be more stringent than CSAPR. Specifically, the state should be able to rely on the EPA's determination that CSAPR resulted in greater reasonable progress than source-specific BART to satisfy the requirements of §51.308(e)(2)(i)(E) and (e)(3).

We acknowledge that other requirements of §51.308(e)(2) would still need to be satisfied, such as monitoring, recordkeeping, reporting, and provisions for emission trading programs. While the CSAPR option is specifically listed at §51.308(e)(4), the EPA's Regional Haze rules do not prohibit a state from relying on EPA's modeling demonstration that CSAPR resulted in greater reasonable progress when using an alternative under §5l.308(e)(2). If a state-only program is more stringent than CSAPR, for example a program based on CSAPR allocations but without interstate trading, requiring a state to conduct extensive modeling to demonstrate what the EPA has already demonstrated for a less stringent program is illogical and places an unnecessary and wasteful burden on states.

Response: We agree with this comment. In response to this comment, our final FIP establishes an intrastate trading program that operates much like the CSAPR program did in Texas. This program is discussed in more detail elsewhere.

3. EPA's Reliance on CSAPR for NO_X BART

Comment: Agree with EPA's proposal regarding CSAPR as a BART alternative for NOx which is proposed for separate finalization. EPA could have followed the D.C. Circuit's directive and updated NOx (and SO_2) budgets for Texas. EPA could have but declined to do so. EPA notes that finalization of CSAPR as better-than-BART for NOx is contingent on a separate finalization that the D.C. Circuit remands would not adversely impact 2012 demonstrations. Uncertainty in this proposal does not seem to be an issue for NOx and EPA is again basing a proposal on an action yet to be finalized.

Response: Whether we were in a position to provide updated annual NOx and SO_2 budgets for Texas is not relevant to this rulemaking. Because Texas EGUs are required to continue participation in CSAPR for ozone transport, which involves NOx trading, we are determining that the NOx BART requirement for EGUs continues to be met through our determination that CSAPR is better than BART.

We interpret the comment as supporting this action, even as it appears to criticize our reference to another proposed action, which has since been finalized, as part of the proposal for the NOx aspect of this action. Our proposed and finalized action for the NOx BART requirement addresses the Act's requirements for Texas. This action and our recent action to remove Texas

EGUs from CSAPR's SO_2 trading program are distinct actions, but we have provided appropriate transparency and notice regarding how the proposed actions relate and have given careful consideration to comments received that have bearing on each of the actions.

Comment: EPA's proposal is unlawful because it exempts sources from installing BART controls without going through the exemption process Congress prescribed. The visibility protection provisions of the Clean Air Act include a "requirement" that certain sources "install, and operate" BART controls. 42 U.S.C. § 7491(b)(2)(A). Congress specified the standard by which sources could be exempted from the BART requirements, which is that the source is not reasonably anticipated to cause or contribute to a significant impairment of visibility in any Class I area. Appropriate federal land managers must concur with any proposed exemption. EPA has not demonstrated that any of the Texas EGUs subject to BART meet the standards for an exemption, nor has EPA obtained the concurrence of federal land managers. Therefore, EPA must require source-specific BART for each power plant subject to BART.

Response: To the extent the comment is directed to the prior rules that determined and redetermined that CSAPR is better than BART and may be relied upon as an alternative to BART, we disagree that relying on CSAPR is in conflict with the CAA provision regarding exemptions from BART. In addition, the commenter's objection does not properly pertain to this action, but instead to our past action that established 40 CFR 51.308(e)(4). We believe this comment to fall outside of the scope of our action here. To the extent the comment objects to BART alternatives generally, we also disagree. In addition, that objection does not properly pertain to this action, but instead to our past regulatory action that provided for BART alternatives.

Comment: Even if EPA could use a BART alternative without going through the statutory exemption process, the CSAPR-Better-than-BART Rule was fatally flawed, and even if it were valid in 2012, is now woefully outdated. EPA's regulations purport to allow the use of an alternative program in lieu of source-specific BART only if the alternative makes "greater reasonable progress" than would BART. 40 C.F.R. § 51.308(e)(2). To demonstrate greater reasonable progress, a state or EPA must show that the alternative program does not cause visibility to decline in any Class I area and results in an overall improvement in visibility relative to BART at all affected Class I areas. *Id.* § 51.308(e)(3)(i)-(ii).

EPA compared CSAPR to BART in the Better-than-BART Rule by using CSAPR allocations that are more stringent than now required as well as by using presumptive BART limits that are less stringent than are actually required under the statute. Even under EPA's skewed 2012 comparison, CSAPR achieves barely more visibility improvement than BART at Big Bend and Guadalupe Mountains. The NOx emissions allowed under CSAPR from Texas EGUs are higher than would be allowed under BART. This was true even before EPA revised CSAPR to increase the emissions allocations for all Texas EGUs.

If it were assumed that the CSAPR-Better-than-BART Rule were valid in 2012, it is based on assumptions for both CSAPR and BART emissions which are now woefully outdated. The CSAPR-Better-than-BART Rule's reliance on presumptive BART emission limits is now outdated, given that EPA has issued or approved source-specific BART determinations for dozens of sources since 2012. In particular, for Texas sources, EPA has proposed SO_2 BART limits which are far below the presumptive BART limits EPA used in the Better-than-BART Rule. For units other than Martin Lake, EPA proposes SO_2 BART limits of 0.04 to 0.06 lbs/MMBtu, which are well below the presumptive SO_2 BART limit of 0.15 lbs/MMBtu; even at Martin Lake, EPA proposes limits of 0.11 to 0.12, which are still below presumptive BART for SO_2.

Similarly, the CSAPR-Better-than-BART Rule is based on a version of CSAPR that no longer exists. Accordingly, any conclusion that EPA made in the 2012 Better than BART rule regarding whether CSAPR achieves greater reasonable progress than BART is no longer valid. Since 2012, EPA has significantly changed the allocations and the compliance deadlines for CSAPR. Of particular relevance here, after 2012, EPA dramatically increased the CSAPR allocations for every covered EGU in Texas. EPA later withdrew the February 21, 2012 rule revision, but issued a new rule that included both the changes in the February 21, 2012 rule as well as additional changes to state budgets.

By the time EPA finalized the Better-than-BART-Rule in June 2012, EPA had changed the state emissions budgets by tens of thousands of tons, yet EPA proceeded to finalize the Better-than-BART Rule based solely on the emissions budgets in the original, 2011 CSAPR rule. EPA also extended the compliance deadlines by three years, such that the phase 1 emissions budgets take effect in 2015-2016 and the phase 2 emissions budgets take effect in 2017 and beyond. Even more changes to CSAPR have occurred as a result of the D.C. Circuit's decision in *EME Homer City II Generation*, including the proposed withdrawal of Texas from the annual NO_X and SO_2 trading programs. Given the large number of final BART determinations made since 2012, and the significant changes to CSAPR budgets since 2012, it is arbitrary and capricious to rely on the outdated assumptions about emissions which were made in the CSAPR-Better-than-BART Rule.

Response: As we had proposed, our finalized determination that CSAPR participation will resolve NOx BART requirements for Texas EGUs is based on a separately proposed and finalized action. This comment falls outside of the scope of our action here.

Comment: EPA's November 2016 "Sensitivity Analysis" purports to update its CSAPR-Better-than-BART analysis to show that CSAPR still makes greater reasonable progress than BART. We agree with EPA that the 2016 Sensitivity Analysis is not a proper legal basis for demonstrating that CSAPR makes greater reasonable progress than BART, because the 2016 analysis is merely a proposed rule. It would be unlawful to issue a final BART rule relying on CSAPR to satisfy the NO_X BART requirements in the absence of a final rule demonstrating that the CSAPR Update makes greater reasonable progress than BART.

To demonstrate that CSAPR makes greater reasonable progress than BART, EPA must show that (1) visibility does not decline in any Class I area under CSAPR, and (2) there is an overall improvement in visibility, based on comparing the average differences between CSAPR and BART across all affected Class I areas. EPA's analysis falls well short of making such a demonstration, as we noted in our prior comments on EPA's 2016 Sensitivity Analysis.

EPA's 2016 analysis is markedly different from the CSAPR-Better-than-BART Rule, which relied on quantitative modeling of electric power section emissions, using the Integrated Planning Model, and quantitative modeling of visibility at all affected Class I areas, using

CAMx. Instead of updating that modeling, EPA's 2016 analysis consists of a back-of-the-envelope, qualitative discussion. This is wholly insufficient. There have been enormous changes in the electric power sector since EPA issued the Better-than-BART Rule in 2012, including changes in regulatory requirements (*e.g.*, CSAPR revisions, NAAQS updates, etc.) and changes in unit operations caused by changes in fuel prices, demand, etc. Given that EPA believed in 2012 that it was necessary to conduct quantitative modeling of power sector emissions and the visibility impacts of such emissions, EPA must update that modeling in order to prove that CSAPR still makes greater reasonable progress than BART.

EPA's failure to update the modeling upon which it relied in the 2012 Better than BART Rule is even more arbitrary given EPA's assumption, in the 2016 Sensitivity Analysis, that no trading of CSAPR allowances would occur across state lines. The Sensitivity Analysis uses "emissions that would occur if the state budgets are increased as proposed assuming that all of the additional allowances are used by sources in the respective state (*i.e.*, we did not re-model trading)." This assumption bears no relationship to reality, in which CSAPR—both the original rule, and the updated rule—expressly allows trading across state lines. EPA's failure to create a realistic depiction of the geographic distribution of emissions under the updated CSAPR budgets dooms its Sensitivity Analysis, as EPA must demonstrate that visibility does not decline in any Class I area. Trading across state lines can increase emissions from particular sources, which in turn can degrade visibility at particular Class I areas. Having failed to consider how inter-state trading will affect the distribution of emissions under CSAPR, EPA cannot possibly show that visibility will not decline in any Class I area under CSAPR.

Similarly, EPA failed to account for intra-state trading under CSAPR. Even assuming all changes in budgets would apply only within the affected state – that is, assuming interstate emissions trading did not change at all – EPA has not accounted for trading within the states. A 20% reduction in statewide emissions does not imply that each unit will reduce its emissions by 20%; indeed, some units could increase emissions while statewide emissions went down. EPA does not seem to have accounted for this in its analysis. Thus, even within EPA's scenario whereby no changes to reflect current conditions need to be made, EPA's *ad hoc* analysis fails to demonstrates that the "Better-than-BART" test above would be met because EPA has failed to account for changes in emissions distribution based on the altered budgets.

In addition, EPA cannot simply assume that the visibility improvement averaged across all Class I areas, 40 C.F.R. § 51.308(e)(3)(ii), will still be better under the updated CSAPR than under BART. Without updated visibility modeling, EPA has no data to demonstrate that the second prong of the BART alternative test will be met in spite of the substantial changes in coverage and budgets under CSAPR.

Response: In part, the comment makes the point that this final action cannot rely on another action that has only been proposed. We agree with this aspect of the comment, but this part of the comment is no longer relevant because the other action has now been finalized. As we had proposed, our finalized determination that CSAPR participation will resolve NOx BART requirements for Texas EGUs is based on a separately proposed and now finalized action. This comment in its discussion of the 2016 sensitivity analysis and other particulars raises issues that are addressed in the record for that separately finalized action. This comment falls outside of the scope of our action here.

Comment: Under the updated version of CSAPR, Texas will not have allowances for annual NO_X emissions. Instead, Texas will have a CSAPR budget for NO_X for only the ozone season, which runs a few months each year. But BART is not a seasonal requirement; BART requires continuous operation of pollution controls. “The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State.” It violates EPA’s regulations to use seasonal emissions reductions under CSAPR to satisfy the BART requirement to install and operate “continuous emission control technology.”

Response: We disagree with this comment, but also note that it should not be directed to this action but rather to the past rulemaking determination that provided BART coverage for pollutant trading under CSAPR as specified at 40 CFR 51.308(e)(4). In any event, the argument that BART must be based on “continuous” control does not transfer to the application and operation of a BART alternative. Sources that would operate under an annual trading program that provides tons per year allocations for a unit are not necessarily applying “continuous” controls either. In fact, they are also free to operate seasonally or with intermittent use of controls so long as they operate within the allocation or purchase allowances whenever emissions may exceed that allocation. We necessarily disagree that EPA regulations would bar seasonal emissions reductions to satisfy requirements for a BART alternative.

4. Other CSAPR Comments

Comment: The EPA should proceed to finalize CSAPR as a better-than-BART alternative not only as to NOx but also as to SO_2. In the Texas Regional Haze SIP, Texas relied on EPA's Regional Haze Rule that allows states to implement an alternative to BART as long as the alternative has been demonstrated to achieve greater reasonable progress toward the national visibility goal than BART. EPA made such a demonstration for CAIR and many states, including Texas, relied on CAIR's cap and trade programs as a BART alternative for EGU emissions of SO_2 and NOx in their SIP submittals. Following EPA's demonstration in 2005 that CAIR is better-than-BART and after Texas submitted the Regional Haze SIP, the D.C. Circuit Court remanded CAIR to EPA but ultimately did not vacate the CAIR rule. EPA approved certain States' SIPs that implemented CAIR as a BART alternative, yet, EPA did not do so for Texas.

CSAPR was issued to replace CAIR and because of EPA's action on CAIR, EPA subsequently withdrew reliance on CAIR as a BART alternative and finalized the demonstration that compliance with CSAPR is better than application of BART. This action occurred after Texas had submitted its SIP.

On December 16, 2014, EPA published a proposed FIP program to "replace reliance on CAIR with reliance on the trading programs of CSAPR as an alternative to BART for SO_2 and NOx emissions for EGUs." The CSAPR rule had been challenged in the D.C. Circuit and the court held that EPA had over-controlled certain States' budgets and remanded the CSAPR rule without vacatur for further revision by EPA. In January 2016, EPA did not finalize BART controls for EGUs, citing uncertainty. EPA issued the CSAPR Update on October 24, 2016 but did not revise SO_2 or NOx annual budgets for Texas.

EPA's Proposed FIP and the imposition of source-specific BART relies on the EPA's proposed rulemaking for the withdrawal of Texas from the CSAPR Phase 2 trading budgets for

SO_2. In November 2016, EPA published a proposal to withdraw the FIP provisions that required affected EGUs to participate in Phase 2 of the CSAPR trading programs for annual emissions of SO_2 and NOx purportedly to address a decision of the U.S. Court of Appeals for the District of Columbia Circuit that had remanded for further consideration the CSAPR Phase 2 SO_2 budgets for Texas and other states.

EPA's proposed withdrawal of Texas from the Phase 2 CSAPR program for SO_2 included a "sensitivity analysis" indicating that removal of Texas from the Phase 2 SO_2 budget trading program (and including the removal of the Florida trading program) would not adversely impact the demonstration that CSAPR participation continued to qualify as an alternative to compliance with BART, in other states that were relying on CSAPR for BART compliance.

EPA also noted that "[n]o changes to the Regional Haze Rule are proposed as part of the rulemaking." *Id.* However, in support of this FIP proposal addressing Regional Haze, EPA notes that it, "had earlier proposed to rely on CSAPR participation to address these BART - related deficiencies in Texas' SIP submittals referencing its December, 2014 proposed FIP." EPA did not address the D.C. Circuit Court's remand as directed.

The D.C. Circuit had remanded without vacatur the Phase 2 budgets in *EME Homer City Generation, L.P. v. EPA, 795 F.3d 118* (D.C. Circuit 2015) and directed the EPA to reconsider the emission budgets and propose revised budgets. AEP said they did not support EPA's proposal to withdraw Texas from CSAPR, stating that the EPA had provided insufficient justification and explanation for the proposal and had not considered the impact on the trading market. AEP noted that the court had specifically not vacated the Phase 2 budgets due to concerns that such a decision would disrupt the trading markets. AEP also expressed concern that withdrawing Texas from CSAPR would impact the compliance strategies facilities have developed for compliance with BART, as BART eligible facilities had developed compliance strategies assuming BART compliance would be achieved through compliance with CSAPR. AEP said they supported the CSAPR trading programs because of their flexibility and administrative convenience, cost-effectiveness and the "remarkable reductions that have occurred across the electric utility industry." AEP also considered EPA's analysis of the impact of sources in Texas on nonattainment areas in other states was inadequate and the explanation provided by EPA for its decision to change the initial determination was insufficient and potentially exposed Texas EGUs to future liability for the impact of PM2.5 emissions on Madison County and other upwind locations. AEP concluded their comments on 81 FR 78954 by recommending the EPA finalize CSAPR as a compliance alternative to BART for SO_2 and revise the Phase 2 budgets, instead of withdrawing Texas from CSAPR.

The D.C. Circuit requires EPA to propose acceptable budgets consistent and confirm that those budgets are a BART alternative and allow Texas to remain in the CSAPR trading program. Source specific controls, then, would no longer be necessary since CSAPR as a BART alternative would provide a more cost-effective, less burdensome and flexible program for compliance with Texas' visibility obligations.

By EPA's reliance on the proposed withdrawal of Texas from the CSAPR trading program for SO_2 as the basis for the proposed Texas BART FIP, EPA is illegally proposing BART controls on facilities premised on a proposed rule. Buttressing the proposed FIP on a proposed-not-yet-finalized rule is inconsistent with the APA. EPA seems concerned with uncertainty created by the remand yet, this action by EPA creates its own uncertainty with regard to whether the proposed withdrawal will be finalized as proposed. The APA requires that an agency provide notice and an opportunity to comment on proposed rules. 5 U.S.C. § 553 (c). An agency must be open to taking comments and responding to them. This necessarily requires that EPA must consider comments from the public *before* finalizing a proposed rule. In fact, the comment period for the proposed withdrawal of Texas from the SO_2 CSAPR budgets ended *after* the date of the proposed BART FIP. Clearly, EPA gave itself no opportunity to consider public comment on the proposed withdrawal prior to relying on it as if it were final as proposed to justify the need for proposing source-specific BART. EPA's actions demonstrate that it had no intention of accepting public comment and had already made up its mind that the proposal would be finalized as proposed, a direct contravention of the APA.

Response: Several contentions provided by this commenter are relevant to the action withdrawing Texas from Phase 2 CSAPR program budget, but given the finalization of that action they are not relevant to this action. We are required to address the BART requirements for both pollutants under our CAA FIP authority, in the absence of an approvable SIP. We are finalizing our proposal that NOx BART is met by continued participation in CSAPR and we are finalizing a BART alternative to address the SO_2 BART requirement. The BART alternative applies the CSAPR allowance allocations for SO_2 to all BART-eligible coal-fired EGUs, several additional coal-fired EGUs, and several BART-eligible gas-fired and gas/fuel oil-fired EGUs. In addition to being a sufficient alternative to BART, it secures reductions consistent with visibility transport requirements and is part of the long-term strategy to meet the reasonable progress requirements of the Regional Haze Rule.

We do not agree with the commenter's suggestion that we were not open to the consideration of comments in our proposed action or in any related actions in violation of the APA. Moreover, the assertion that EPA had made up its mind that any proposal would be finalized as proposed regardless of comments that might be offered is not correct. For efficiency and because of time constraints, our proposal for the NOx aspect of this action was based on a scenario of later finalization of the CSAPR remand response rule, but that does not mean that we did not fairly consider all comments on the CSAPR remand response rule or pre-decided the outcome of that rule. Our final decisions in this action reflect the final CSAPR remand rule, and consideration of comments on our proposal for this action.

Comment: Recommend the CSAPR budgets be revised. Revising the CSAPR budgets is supported by actual SO_2 emissions. The Texas EGU SO_2 and NOx emissions have steadily decreased and have fallen well below 2017 CSAPR budgets. These emissions are well below the original better-than-BART budgets for SO_2. EPA’s determinations that CSAPR is better-than-BART is still valid and supported even if emissions were increased.

We anticipate that EPA may respond that a September 9, 2017 Consent Decree deadline (derived from a case in which the EGUs were not party) did not permit time to consider comments before proposing the Texas BART FIP. Clearly, the most expeditious approach would be for EPA to revise the invalid Phase 2 CSAPR budgets for Texas and propose that reliance on the revised budgets satisfies BART compliance. Any delays in addressing Texas’ BART obligations are the result of EPA not establishing an acceptable CAIR or CSAPR program, and EPA’s refusal to revise CSAPR Phase 2 budgets and not Texas’ failure to agree to accept invalid CSAPR budgets. In fact, the D.C. Circuit instructed EPA to act “promptly” in revising the budgets.

Additionally, EPA’s attempt to comply with a court deadline does not justify noncompliance with the APA. With its current proposal (Texas BART FIP), EPA has done nothing but create further uncertainty and violate the APA. EPA could have requested an extension of the deadline to revise the budgets, but did not. Consistent with the Administration's Executive Order on Reducing Regulation and Controlling Regulatory Costs, EPA could revise the CSAPR budgets adhere to CSAPR is better-than-BART, as they have in many other states, and remove two proposed regulations in doing so without the promulgation of another rule (proposed withdrawal of Texas from the CSAPR Phase 2 program and proposed source-specific BART for Texas source.) EPA should update the Phase 2 SO_2 budgets as directed and post-haste proceed to finalize CSAPR as a better an alternative to the application of source-specific BART.

Response: Texas declined to submit a SIP to voluntarily participate in CSAPR and we have addressed our remand obligations for Phase 2 SO_2 budgets by ending Texas EGU participation in CSAPR for $PM_{2.5}$ transport. We agree, however, that Texas sources can continue NOx BART coverage under CSAPR and we are finalizing a BART alternative for SO_2 instead of establishing source-specific SO_2 BART determinations for units at those sources. The BART alternative applies the CSAPR allowance allocations for SO_2 to all BART-eligible coal-fired EGUs, several additional coal-fired EGUs, and several BART-eligible gas-fired and gas/fuel oil-fired EGUs. In addition to being a sufficient alternative to BART, it secures reductions consistent with visibility transport requirements and is part of the long-term strategy to meet the reasonable progress requirements of the Regional Haze Rule.

Comment: EPA is now proposing to require stringent emission control technology on units that have already met the BART obligations by participation in the regional trading programs, CAIR, and its replacement, CSAPR. In this proposal, EPA has effectively removed a cost-effective compliance mechanism which has been in place for the duration of the first planning period, with costs and reductions that far exceed the regulatory obligation, with limited or no benefit to visibility. Because it was only late last week that EPA made available the technical documents that it claims would support its action and EPA has yet to provide us with the specific modeling supporting the proposal that we requested several weeks ago, We have not yet had an opportunity to thoroughly evaluate EPA's technical justification for the proposal.

Response: Our proposal did not effectively remove CSAPR, and we disagree with the comment's characterization of how and when CSAPR has been "in place." Regardless, we agree with the premise of the comment that SO_2 BART and NOx BART for Texas EGUs can be addressed by the BART alternatives we rely on in our final action. We also disagree that our proposal would have provided limited or no benefit to visibility to the extent it suggests our final action is not providing visibility benefits. Visibility benefits are being secured and preserved into the future by the final FIP measures.

Comment: Texas' SO_2 emissions are below the levels that EPA has found to be better-than-BART, and any reasonable assessment would conclude that trends of anticipated emissions in Texas will remain below those levels. EPA conducted two sensitivity analyses that both demonstrate that revised CSAPR emission levels for Texas are better-than-BART. We compared actual Texas EGU SO_2 emissions in 2015 and 2016 to the SO_2 emission levels that EPA found are better-than-BART. In both cases, Texas' actual emissions are well below the budgets that EPA has determined are better-than-BART.

Response: We are finalizing a BART alternative that applies the CSAPR allowance allocations for SO_2 to all BART-eligible coal-fired EGUs, several additional coal-fired EGUs, and several BART-eligible gas-fired and gas/fuel oil-fired EGUs. In addition to being a sufficient alternative to BART, it secures reductions consistent with visibility transport requirements and is part of the long-term strategy to meet the reasonable progress requirements of the Regional Haze Rule. To the extent, the comment suggests that current and anticipated emissions alone are enough to satisfy requirements for BART or a BART alternative, we disagree. As a fundamental matter, emissions reductions must be enforceable to prevent undesired and unexpected increases in future years. Pointing to “trends”—i.e., unenforceable emissions levels without legal requirements against future increases--does not meet CAA requirements.

Comment: EPA must promulgate or approve a BART alternative for Texas, and must not finalize the unlawful and cost-prohibitive proposed Texas BART FIP. EPA should not, and lawfully may not, finalize its Proposed Texas BART FIP. The Proposed Texas BART FIP—like the predecessor Reasonable Progress Rule that is stayed and was remanded by the Fifth Circuit for reconsideration—is fundamentally flawed, cost-prohibitive to implement, and contrary to reasoned decision-making. EPA should address BART for Texas—not through federally-mandated specific controls on individual units—but through one of several available BART alternatives that will achieve equivalent or greater benefits at far less costs, as demonstrated by EPA’s own prior modeling and sensitivity analyses.

Among those available alternatives is EPA’s original proposed BART action for EGUs in Texas—reliance on Texas EGUs’ participation in CSAPR’s annual SO_2 and NO_X trading Programs as BART compliance. That alternative remains the most expeditious and defensible path for finalizing a BART solution for Texas EGUs, and it is fully supported by EPA's previous CSAPR better-than BART modeling and sensitivity analyses. Indeed, EPA's *only* lawful path forward to finalize a BART FIP for Texas by the current September 9, 2017 deadline in EPA's consent decree with Sierra Club is to finalize a CSAPR-for-BART FIP for Texas EGUs, as EPA signed in December 2014. For the many reasons discussed in Section II of these comments, EPA would be acting unlawfully were it to finalize the Proposed Texas BART FIP as issued in December 2016.

As an alternative to finalizing a CSAPR-for-BART FIP in September 2017, EPA could seek an extension of the consent decree deadline and proceed to work cooperatively with the State of Texas and Texas EGU operators to develop and propose for comment a different BART alternative for Texas, as it has done in other states. Such an alternative could, for example, establish SO_2 emission caps for Texas EGUs that are comparable to CSAPR budgets and would thus fall squarely within EPA's previous CSAPR=BART demonstration and sensitivity analyses for Texas. EPA has frequently worked with states and stakeholders to develop workable BART alternatives for EGUs, and it should do the same here with Texas and Texas stakeholders, including Luminant.

Promulgation of a CSAPR-for-BART FIP is EPA's only lawful option for meeting the September 9, 2017 consent decree deadline. If EPA believes that it must finalize a BART rule for Texas EGUs by September 2017, EPA's only valid legal option is to finalize its 2014 proposed CSAPR-for-BART FIP. In that proposal, EPA specifically stated that it was proposing "a FIP to replace reliance on CAIR with reliance on the trading programs of CSAPR as an alternative to BART for SO_2 and NO_X emissions from EGUs in the regional haze plan for Texas." In support, EPA explained that it "determined that [1] CSAPR provides for greater reasonable progress towards the national goal than would BART and [2] Texas is included in CSAPR for NO_X and SO_2." The same is true today, and, indeed, recent emission trends and EPA's sensitivity analyses for Texas confirm that CSAPR is and remains better-then-BART for Texas EGUs. Texas remains in the CSAPR annual programs for NO_X and SO_2, and EPA's determination that CSAPR provides for greater reasonable progress than the installation of BART remains scientifically sound. EPA has determined that "[CSAPR] achieves greater reasonable progress towards the national goal of achieving natural visibility conditions than source-specific BART." That conclusion remains valid today, and EPA has not undertaken any action to revise or rescind that rulemaking. In fact, the Eighth Circuit recently upheld EPA's conclusion that CSAPR is better than BART, stating that "EPA's explanation that the Transport Rule is better than source-specific BART is rational." There is no legal or technical barrier to EPA finalizing its original proposal of CSAPR-for-BART for Texas EGUs, and, indeed, that is EPA's only lawful current option if it were to meet the September 2017 deadline.

EPA's consent decree with Sierra Club does not prevent EPA from finalizing its original CSAPR-for-BART proposal in Texas. The consent decree that EPA entered into with Sierra Club was revised in December 2015 to provide two alternative deadlines for issuing a final rule that implements BART for Texas. First, the revised consent decree provides that by "[n]o later than December 9, 2016," EPA was to promulgate a final BART FIP for Texas, unless EPA had approved Texas's SIP or promulgated "a partial SIP" meeting the BART requirements under the regional haze program. Alternatively, the December 2016 deadline would be "extended to September 9, 2017," if EPA signed a new proposed rule for BART by December 9, 2016. EPA signed the Proposed Texas BART FIP on December 9, 2016, thereby triggering the extension in the consent decree.

The consent decree, however, does not (and cannot) dictate the substance of EPA's final BART rulemaking under the extended deadline of September 9, 2017; the only prerequisite to invoking this extension is the signing of a proposal by December 9, 2016. EPA is not bound by the consent decree to finalize the terms of the current proposal or any similar source-specific BART rule; in fact, established principles of administrative law require EPA to remain open-minded during the rulemaking process. The consent decree merely established deadlines for EPA's pending course of action. Accordingly, for purposes of meeting the upcoming deadline of September 9, 2017, EPA is not prohibited by the consent decree from reverting to its 2014 proposal to finalize CSAPR as a BART alternative for Texas EGUs.

Response: We agree that the existence of the consent decree deadline does not dictate the substance of our action to address Clean Air Act requirements to meet the deadline. We disagree that our only possible lawful action for meeting the deadline is to impose a FIP based on CSAPR. 40 CFR 51.308(e) requires that states submit a SIP containing emission limitations that represent BART for BART eligible sources that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. Alternatively, 40 CFR 51.308(e) allows states to establish an emissions trading program or other alternative as long as the trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions than BART. Where a state has failed to submit a SIP by the applicable deadline or has submitted a SIP that has been disapproved by the EPA, the CAA authorizes and requires EPA to promulgate a FIP that meets the requirements of the applicable federal statutes and regulations. Thus, EPA has the authority to promulgate a FIP containing emission limits that represent BART for BART eligible sources that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. Alternatively, EPA may establish an emissions trading program or other alternative which will achieve greater reasonable progress than BART. We are meeting requirements with valid use of discretion where appropriate to finalize NOx BART as proposed, and to finalize a BART alternative with emission levels similar to CSAPR to address SO_2 BART. We are not able to revive the 2014 proposal to satisfy SO_2 BART for Texas EGUs because remand obligations have led to the removal of SO_2 trading requirements for Texas. We agree that this might have been a viable solution, but Texas declined to submit a SIP to voluntarily participate in CSAPR to fully preserve and accommodate this option.

Comment: The Proposed Texas BART FIP is not only cost-prohibitive, it is not necessary to achieve the goals of the Regional Haze Program and satisfy the requirements of the CAA. EPA's own prior modeling and analysis show that BART for these units is more than met by current SO_2 emission levels from Texas EGUs, and the stringent additional limits in the Proposed Texas BART FIP are not necessary.

EPA's sensitivity analyses for Texas's SO_2 CSAPR budgets and recent emission trends in Texas demonstrate that CSAPR remains better-than-BART. EPA's sensitivity analyses definitively confirm that EPA's determination that CSAPR is better-than-BART in Texas remains scientifically sound. When EPA issued the final rule promulgating the CSAPR-for-BART provision in June 2012, EPA confirmed that the upward adjustments to Texas's budgets under CSAPR did not adversely impact visibility conditions in nearby Class I areas. EPA initially calculated visibility improvements for nearby Class I areas based on a SO_2 budget for Texas of 243,954 tons/year. Following EPA's upward adjustments to the CSAPR budget due to errors in EPA's initial calculation, EPA revised its visibility improvement estimates based on a SO_2 budget of 294,471 tons/year. EPA's methodology demonstrates the expected visibility improvement as a result of implementing the CSAPR is better-than-BART provision under the original budget and the revised budget. Even with an SO_2 budget of nearly 300,000 tons for Texas, visibility at these Class I areas was projected to improve (not degrade).

Recent emissions data confirm EPA's prior determination—*i.e.*, that Texas's emissions are well below the threshold that was previously determined to be better-than-BART. Implementation of CSAPR Phase 1 began in 2015, and implementation of Phase 2 began in 2017. For 2015 and 2016—during CSAPR Phase 1—Texas maintained its annual emissions of SO_2 and NO_X well under the budgets established by EPA. The state-wide budget for annual SO_2 in Texas is 294,471 tons, and the state-wide budget for annual NO_X in Texas is 137,701 tons. These same budgets will apply during Phase 2, and there is no expectation that Texas EGUS will exceed these thresholds. In fact, EPA's own data demonstrate that Texas has not exceeded, or even approached, its annual allowance allocations for either SO_2 or NO_X during Phase I of CSAPR. Emissions of SO_2 from Texas EGUs were 260,122 tons in 2015 and 244,233 tons in 2016. As for NO_X, emissions from Texas EGUs were 107,921 tons in 2015 and 106,625 tons in 2016. Once CSAPR became effective in Texas in 2015, SO_2 emissions from Luminant's coal-fired EGUs dropped dramatically and have trended downward. There is no reason to believe, and EPA presented no reason, that this trend will reverse—and certainly not to a degree that Texas EGU SO_2 emissions would exceed CSAPR budgets or call into question EPA's CSAPR better-than-BART demonstration.

Texas has maintained its emissions well below the budgets established by CSAPR. The record establishes that BART for these units can be no more stringent than current emission levels, which are well below CSAPR budgets. In 2012, EPA concluded that "[CSAPR] achieves greater reasonable progress towards the national goal of achieving natural visibility conditions than source-specific BART." EPA confirmed this determination in subsequent sensitivity analyses. So long as Texas's emissions remain below the CSAPR budgets, the operation of Texas EGUs in such a manner will continue to be better-than- BART.

Thus, the Proposed Texas BART FIP is based on a fundamental flaw by EPA—that BART for Texas EGUs must be "more emission reductions than projected under CAIR or CSAPR." To the contrary, because Texas validly remains in the annual CSAPR programs for SO_2 and NO_X combined with the fact that Texas EGU SO_2 emissions are well below the annual allocations, EPA has no valid basis to change course from its 2014 proposal to finalize CSAPR for BART in Texas in order to impose more stringent source-specific BART controls. EPA should proceed to finalize a FIP for Texas that approves CSAPR as a BART alternative for Texas EGUs.

Response: We agree that emissions similar to the CSAPR budgets would be better than BART and can be justified as a BART alternative. To the extent the comment suggests that merely pointing to current emissions level can satisfy the requirements of a BART alternative, we disagree. Those emissions levels must be made enforceable, and our final action accomplishes that. NOx BART for EGUs is addressed by continued participation in CSAPR program for ozone transport. With regard to SO_2, the BART alternative is designed to achieve SO_2 emission levels from Texas EGUs similar to the SO_2 emission levels that would have been realized from the SO_2 trading program under CSAPR. These measures will assure Texas' recent reductions of SO_2 and NOx will be maintained and improved upon in the future.

Comment: The D.C. Circuit's remand of CSAPR budgets does not create "uncertainty" that prevents EPA from finalizing CSAPR-for-BART for Texas EGUs. EPA says that it did not finalize its initial CSAPR-for-BART proposal for Texas EGUs because it noted some "uncertainty arising from the remand of Texas' CSAPR budgets" by the D.C. Circuit. EPA made that claim in the now-stayed January 2016 Reasonable Progress Rule. That claim was wrong when it was made then, and it is clearly wrong now. There is no "uncertainty." The D.C. Circuit's remand does not prevent EPA from finalizing CSAPR as an SO_2 BART alternative for Texas EGUs.

First, EPA's claim that there is an "absence of CSAPR coverage for SO_2" in Texas following the D.C. Circuit's remand is simply wrong. Texas EGUs are and have been regulated by a BART equivalent trading program for the entirety of the first planning period to date—first through CAIR and, after CAIR's replacement and up to the present day, through CSAPR. Texas EGUs are presently subject to CSAPR's annual SO_2 and NO_X programs under the budgets remanded by the D.C. Circuit, which are budgets that EPA has confirmed as better-than-BART. EPA's prior determination that CSAPR is better-than-BART for all states, including Texas, is scientifically sound and remains a binding part of EPA's regulations. EPA may properly respond to the D.C. Circuit's remand by revising Texas's annual SO_2 budget (as instructed by the D.C. Circuit) *after* it finalizes the proposed CSAPR-for-BART FIP for Texas.

Second, regardless of when EPA responds to the D.C. Circuit's remand, EPA's own sensitivity analyses confirm that were EPA to properly respond to the remand by increasing Texas's annual SO_2 budgets so they do not over-control as instructed by the D.C. Circuit, those revised budgets would remain better-than-BART. EPA established a multi-step methodology to analyze whether increases in Texas's SO_2 annual budgets would change EPA's CSAPR better-than-BART determination (which remains part of EPA's binding regulations). First, EPA's methodology for conducting a revised sensitivity analysis requires the identification of the Class I areas in and near Texas that that are most likely affected by Texas emissions. Second, EPA's analysis then "employ[s] [the] very conservative" assumption that "all of the visibility improvement" that EPA's CSAPR better-than-BART modeling predicted for these nine areas as a result of *all* CSAPR reductions from *all* covered states is "solely due to [reductions] from Texas." Third, with this conservative assumption, EPA then "proportionally reduce[s]" the modeled visibility improvements at these nine Class I areas based on the corrected higher SO_2 budget for Texas. For example, if, in response to the D.C. Circuit's remand, EPA were to adjust Texas's budget to 350,000 tons, CSAPR would still be better-than-BART for Texas and other states. Such an adjustment would be equivalent to a 57% reduction in the number of SO_2 tons reduced compared to the original Texas CSAPR reductions that were modeled for EPA's original CSAPR better-than-BART modeling. EPA's methodology would thus reduce the visibility benefit accordingly by multiplying the visibility improvement at the Class I areas affected by Texas by a factor of 0.43. Thus, for example, the visibility improvement at Wichita Mountains from CSAPR, even after increasing Texas's budget to 350,000 tons, would be 0.688 deciview [1.6 deciview x 0.43 = 0.688]. This methodology could be applied to other budgets as well. Visibility improvements at nine Class I areas in or around Texas result from the application of EPA's sensitivity analysis of a hypothetical adjustment of Texas's CSAPR SO_2 budget to 350,000 tons per year. Thus, EPA's own modeling shows that visibility at these Class I areas is projected to improve (not degrade) and that the BART requirements are met even if the CSAPR budgets are increased.

Response: We have completed our response to the CSAPR remand by withdrawing Texas EGUs from CSAPR requirements for $PM_{2.5}$ transport. We did not act to upward adjust Texas' SO_2 budget. Whether that was a proper response to the remand or whether upward adjustments would have preserved the analytic demonstration that CSAPR is better than BART are not issues of concern with the present finalized action. To the extent the comment asserts that CSAPR budgets can be used to support a better than BART alternative, we agree with the comment and this concept is part of the BART alternative and weight of the evidence that we deem to justify it.

Comment: The proposed rule is legally dependent on other pending proposed rulemakings. EPA may not proceed with this action without first finalizing other proposed rules under the CAA on which this action is based.

Since 2009, Texas EGUs have been subject to federal regulatory programs that have resulted in substantial reductions in the NOx and SO_2 emissions that have been targeted by EPA as contributing to interstate transport and haze. In compliance with EPA rules and precedent, Texas relied on CAIR, and then its replacement CSAPR as achieving reductions in haze precursors from EGUs that are "better than BART" in its Texas Regional Haze SIP submittal. In the unlawful proposed rule, EPA rejects its prior position that Texas EGUs are exempt from BART due to participation in CSAPR. Yet, Texas EGUs continue to this day to be subject to CSAPR requirements for NOx and SO_2. While EPA has proposed to withdraw CSAPR SO_2 requirements for Texas EGUs, it has not yet done so and those EGUs remain subject to CSAPR allocations for both NOx and SO_2 under federal and state laws and permits. Additionally, EPA's proposal to withdraw the CSAPR FIP with respect to SO_2 has been challenged in that rulemaking docket as unlawful and not in accordance with the court decision remanding that action to EPA.

As a result, EPA may not proceed with the disapproval of Texas' reliance on CSAPR as "better than BART" until such time that the proposal is legally finalized in compliance with the Court decision that remanded that rule to EPA. Once that rule is legally finalized, then Texas should be given an opportunity to address whether and how that affects the state's regional haze program before a FIP is considered.

Response: As was made clear by our proposal, we agree our rule is dependent on other proposed and now finalized rulemakings. Nothing in our proposal or final action prevents Texas from addressing the State's regional haze program under its SIP planning authorities. Texas did not request that we withhold our action to withdraw CSAPR SO_2 requirements for Texas EGUs, and it did not submit comments to oppose that action. We disagree that anything in the sequencing of actions would allow us to suspend our FIP obligations when there is no SIP to address the requirements.

Comment: The effort to impose BART controls is the result of the proposed withdrawal of Texas from the CSAPR Phase 2 or annual trading program for SO_2. Compliance with regional haze obligations for BART-eligible facilities in Texas has depended on CAIR-equal BART and CSAPR-equal BART and removing Texas from CSAPR results in significant disruption and costs to planned future compliance for these facilities. EPA seeks these excessive controls which will achieve limited visibility benefits. EPA should take the proper approach and follow the remand without vacatur of the D.C. Circuit, revise the trading budgets and then finalize CSAPR as compliance strategy for BART in lieu of this proposal.

Response: We completed our response to the CSAPR remand in a separate action and refer Commenter there. We are finalizing a BART alternative for SO_2 BART.

E. Comments on the Identification of BART-eligible Sources

Comment: We received comment from the owners of Coleto Creek stating that in the Texas Regional Haze SIP, TCEQ determined that Coleto Creek Unit 1 was not a BART-eligible source, based on its interpretation and application of its SIP-approved regional haze rules at 30 TAC Chapter 116, Subchapter M. In implementing its rules, TCEQ prepared questionnaires that sought the information needed to render its BART-eligibility determinations.[66] As a result of this TCEQ-led process, TCEQ determined that Coleto Creek Unit 1 was not BART-eligible because it was not built, and did not commence operation, until 1980, which is well after the August 7, 1977 applicability date. Coleto Creek Unit 1 has reasonably relied on the state's eligibility determination in evaluating its obligations under the Regional Haze Rule program. EPA's decision to reject TCEQ's BART-eligibility determination for Coleto Creek Unit 1 under 30 TAC 116.1500 is unsupported.

Response: The commenter states that because Coleto Creek Unit 1 did not commence operations until 1980, it should be determined to be not BART-eligible, as was determined by

[66] *See* October 24, 2005 letter from Al Espinosa, Coleto Creek Power Station, #TX187-0023-0001, Docket Item No. EPA-R06-OAR-2016-061l-0023 at p. 6.

the TCEQ. However, we believe the TCEQ erred in not listing Coleto Creek Unit 1 as being BART-eligible. The date test for BART-eligibility is whether the units was "in existence on August 7, 1977," and began operation after August 7, 1962. The BART rule defines as "in existence on August 7, 1977" as follows (70 FR 39159):

> What does ''in existence on August 7, 1977'' mean?
>
> 2. The regional haze rule defines ''in existence'' to mean that:
>
> ''the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.'' 40 CFR 51.301.

The owner of Coleto Creek Unit 1 provided information that onsite construction began prior to August 7, 1977. Thus, Coleto Creek Unit 1 satisfies the above criteria as being "in existence on August 7, 1977." Therefore, we disagree with the commenter and continue to find that Coleto Creek Unit 1 is BART-eligible. The NOx BART requirement for Coleto Creek is met by relying on CSAPR as an alternative to EGU BART for NO_X. The SO_2 BART requirement is met by the intrastate trading program FIP that we are finalizing in this action and to which Coleto Creek will be subject. The PM BART requirement is met by our determination that the visibility impacts of PM emissions from Coleto Creek are too small to be considered to cause or contribute to visibility impairment at any Class I area and we determined the facility screens out and is not subject to PM BART.

F. Comments on PM BART

We previously proposed to disapprove the SIP's subject-to-BART determinations for PM, on the grounds that the SIP had based these determinations on reliance on a BART alternative for SO_2 and NOx and, as a result, considered only the contribution of PM emissions to visibility impairment, and to adopt source-specific PM emission limits to fill the SIP gap. In that context, we received several comments related to PM BART issues. Now, however, we have determined it is appropriate to adopt a BART alternative to address SO_2 and NOx and therefore find Texas' original SIP was correct in considering only the contribution of PM emissions. Considering only PM emissions, all sources considered in the Texas SIP were demonstrated to screen out of the need for source specific PM BART emission limits.

Also, as explained above, we have identified additional sources as BART-eligible that were not considered in the 2009 Texas Regional Haze SIP. As discussed elsewhere, we have determined that the impact due to PM emissions from these additional sources are also below the BART screen level. Thus, the SIP's determination that none of the BART-eligible EGUs are subject-to-BART for PM is correct and approvable. As a consequence, there is no SIP gap needing to be filled by a FIP. Because we are approving EGU PM BART screening determinations that result in no EGUs being subject to PM BART analysis, comments supporting or alleging errors in the details of our PM BART five-factor analysis and our proposed PM BART technology selections and emission limits are not relevant. We address in this section comments that are relevant to whether it is appropriate to approve the portion of this 2009 SIP submission and EPA's analysis in our proposal that determined that no PM emission limits for Texas EGUs are needed to satisfy the BART requirement because the visibility impacts of PM emissions from BART-eligible EGUs do not cause or contribute to visibility impairment. The information in section III.A. on the history of our proposals regarding the EGU PM BART element of the 2009 Texas SIP submission and EPA's proposals is useful background for understanding the comments and our responses on this topic.

Although we are not finalizing the MATS-based PM limits proposed as PM BART for the coal-fired EGUs, this regional haze action does not affect the existing MATS requirements for these units. We are also not finalizing the fuel oil sulfur percentage limits that we proposed for gas/fuel oil-fired EGUs; the same limits in existing permits for these sources are not affected by our action.

Comments: AEP states that we provide no basis for not approving the TCEQ's PM BART determination in 2016 or logical support for our decision to proceed with modeling PM in the proposed Texas BART FIP. AEP believes that when a state is provided statutory deference in implementing the Regional Haze program, EPA must support its decision for not approving the state's determination. While AEP also agrees that current PM requirements for sources complying with MATS are sufficient for meeting PM BART for Welsh Unit 1, it disagrees that PM BART is even warranted at all or that EPA has provided adequate basis for declaring that TCEQ's screening analysis is no longer reliable. AEP says that buried in a footnote, EPA grasps at some claim of error that Texas' PM BART determinations only looked at the impact of PM emissions on visibility, that Texas can only take this approach when the BART requirements of NOx and SO_2 are satisfied, and that Texas' error of not identifying several PM BART eligible sources is grounds for disapproval. AEP believes this logic is unfounded and the situation is created by EPA's piecemeal approach to rulemaking. AEP agrees with EPA's conclusion that gas-fired units that occasionally burn fuel oil should have no further control. AEP will limit burning fuel oil with a sulfur content of 0.7% as currently required by its permit. However, EPA has not provided sufficient reasons to be addressing PM BART. EPA should finalize its earlier proposal to approve Texas' determination that sources in Texas are not subject to PM BART.

The Lower Colorado River Authority disagrees with the disapproval of the Texas PM BART demonstration.

The TCEQ and the Public Utilities Commission of Texas stated that our reliance on language in a guidance memo[67] to bar TCEQ from conducting pollutant-specific modeling to determining BART eligibility was incorrect. The TCEQ believes this memo did not state that the TCEQ's pollutant-specific modeling is only appropriate when BART for other pollutants is satisfied with a BART alternative such as the CAIR or CSAPR. The TCEQ believes the memo states that such modeling may be appropriate where an alternative program is used for other pollutants. The TCEQ also believes we incorrectly claimed that its SIP acknowledges PM-only modeling is inappropriate where an alternative to BART is not employed.[68]

The TCEQ states that our CAMx modeling supports the conclusions from the screening modeling conducted by it that shows these same units did not meet the 0.5 deciview (dv) threshold.[69] Furthermore, the TCEQ states that we found that for gas-fired units, PM emissions are "inherently low," and that existing controls plus compliance with the MATS filterable PM

[67] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, Joseph Paisie, EPA Geographic Strategies Group, July 19, 2006.
[68] Technical Support Document for the Texas Regional Haze BART Federal Implementation Plan, BART FIP TSD, Docket ID No. EPA-R06-OAR-2016-0611-004, page 26, footnote 39.
[69] *Id*, at 82.

limit of 0.03 lb/MMBtu is already BART, further supporting its conclusion that there are no significant visibility impacts from PM emissions from these sources and BART controls for PM are unnecessary. Thus, the TCEQ reasons, a FIP for PM BART is unnecessary and the EPA should approve the screening modeling the TCEQ conducted, as we proposed to do in January 2015.

Luminant provided comments similar to those above. Luminant added that it believes that Texas remains in CSAPR so there is no basis for us to deviate from our prior proposal to approve Texas's PM BART determination. Luminant also stated that our reliance on a Ninth Circuit Court decision to support our rejection of pollutant-specific BART screening is incorrect because the case in point relied upon the BART de minimis exemption, which does not apply in this instance.

Response: We are approving the EGU PM BART element of Texas's 2009 SIP submittal. Under the combination of reliance on the CSAPR ozone-season NOx trading program to satisfy NOx BART and reliance on the FIP's intrastate trading program for SO_2 emissions to satisfy SO_2 BART, it is appropriate for determinations of whether a BART-eligible EGU is subject to BART for PM to be based only on the visibility impact of the source's PM emissions. It is not necessary for us to respond to the comments stating that a PM-only analysis would be appropriate even if both SO_2 and NOx were not addressed by trading programs.

In particular, TCEQ's comments are correct that the BART Guidelines do not prohibit pollutant-specific screening. The July 19, 2006 guidance memo states that EPA does not generally recommend a pollutant-specific screening approach, however, such a screening approach may be appropriate for PM in certain situations. The memo provides the situation of a state relying on

CAIR for NOx and SO_2 BART as an example where pollutant-specific screening for PM may be appropriate. We agree with TCEQ that the memo's intention is not to limit PM-only analysis to SIPs that rely on CAIR. While we disagree with TCEQ's position that a PM-only analysis is appropriate in a situation involving source-specific SO_2 BART emission limits, the approaches promulgated here for SO_2 and NOx BART are BART alternatives and are similar to the CAIR situation described in the memo. Therefore, we find that the pollutant specific PM screening approach in TCEQ's original 2009 SIP submittal is appropriate and demonstrates that the sources covered by the BART alternative program for SO_2 screen out of PM BART. For BART-eligible EGU sources not participating in the BART alternative program for SO_2, all these sources screened out of BART for all visibility impairing pollutants utilizing model plants and CALPUFF modeling as described in our proposed rule and BART Screening TSD. Therefore, we are approving the determination that no Texas EGUs are required to have source-specific PM emission limits in order for the BART requirement to be met. This approval is consistent with our December 2014 proposal for PM BART, in which EPA proposed to rely on Texas' CSAPR participation for SO_2 and NOx BART and to approve the SIP's determinations regarding the need for PM emission limits. *See* 79 FR 74817, 74848 (January 13, 2015). We are also determining that other sources that EPA identified in our December 2016 proposal as BART-eligible that were not identified as BART eligible in TCEQ's 2009 Regional Haze SIP are also screened out from PM BART.

Comment: The Sierra Club states that we should finalize our proposed disapproval of Texas's PM BART determinations, which assumed that SO_2 and NO_X emissions contributing to PM formation would be regulated under CSAPR, *see* 82 Fed. Reg. at 935. Following the D.C. Circuit Court's remand of CSAPR, SO_2 emissions from Texas sources are no longer limited by

CSAPR. The assumption underlying Texas's PM BART determinations—that CSAPR would limit emissions of PM precursors from Texas sources—is now inaccurate; therefore, reasons the Sierra Club, we must disapprove the State's PM BART determinations.

Response: We note that the D.C. Circuit Court remanded the budget for Texas EGUs in the CSAPR trading program for SO_2 without vacatur, so the commenter's statement that Texas EGUs are no longer limited by CSAPR was not true at the time the comment was offered. It is true now as a result of our recent action to remove Texas EGUs from the annual SO_2 and NOx trading programs. However, a large set of Texas EGUs will, under the final FIP, be subject to CSAPR for ozone-season NOx and the intrastate trading program FIP for SO_2. For these EGUs, the BART guidelines and our guidance allow for the subject-to-BART for PM determination to be based on only the impacts of PM emissions on visibility. For the BART-eligible EGUs that will not be required to participate in the FIP's intrastate trading program, our analysis indicates that even when all three pollutants are included in the modeling, all of these sources affect visibility at surrounding Class I Areas by less than 0.5 dv, thus screening out of being subject to PM BART.

Comment: EPA in its previous rulemaking on the reasonable progress measures for the Texas and Oklahoma regional haze plans initially proposed to accept Texas' finding that no PM BART controls were necessary for EGUs "based on a screening analysis of the visibility impacts from just PM emissions...." In its current Texas BART rulemaking, EPA states that "[i]n connection with changed circumstances on how Texas EGUs are able to satisfy NOx and SO_2 BART, we are now proposing to disapprove the portion of the Texas Regional Haze SIP that evaluated the PM BART requirements for EGUs." The changed circumstances EPA refers to is the removal of Texas sources from the SO_2 caps of the CSAPR rule. Unless a source is subject to a BART alternative or is otherwise determined to be exempt from BART for a particular pollutant, EPA's regulations and BART guidelines do not generally provide for exemptions from a five-factor BART analysis for a specific pollutant. Under EPA's BART Guidelines and the definition of BART, once a source has been determined to be subject to BART, a five-factor BART analysis must be done for each pollutant pursuant to 40 C.F.R. Part 51, §51.301 and Appendix Y, section IV.A. So, EPA is correct that it must address BART for PM for the BART-subject sources in Texas.

Response: The premise in the comment that EGUs in Texas will not be subject to a BART alternative for both NOx and SO_2 is incorrect, given the content of this final action.

Comment: Coleto Creek Unit 1 should not be subject to any FIP emission limits, because it should not be determined to be BART-eligible.

Response: Texas' 2009 SIP submission did not include Coleto Creek Unit 1 as a BART-eligible source and consequently the SIP did not present any analysis of whether it is subject-to-BART, while we are determining in this action that Coleto Creek Unit 1 is BART-eligible. However, we evaluated the available modeling and other analyses and we have concluded that this information shows minimal impacts from PM from this particular BART-eligible source. Modeled PM impacts from Coleto Creek Unit 1 are expected to be much less than 0.32 delta deciviews (see Section III.4).

Comment: Requiring the Stryker and Graham units to switch to ultra-low-sulfur diesel would significantly improve visibility. Requiring this switching at Stryker would improve visibility by more than 0.5 dv at Caney Creek, and switching to ultra-low-sulfur diesel at Graham would improve visibility by 0.85 dv at Wichita Mountains.

Response: Insofar as this is a comment on our proposed source-specific FIP emission limits to address BART for PM, it is not necessary for us to respond because we are approving the SIP and not promulgating any such limits in this action. We note that the cited visibility benefits of switching to low-sulfur fuel reflect assumed reductions in both direct PM emissions and SO_2 emissions from these two sources. The Stryker and Graham units are both covered by the intrastate trading program for SO_2 and CSAPR for NOx, so it is appropriate that the subject-to-BART determination be made on the basis of the impacts of direct PM emissions alone. Those impacts are less than 0.5 dv.

Comment: Texas identified 126 sources as BART-eligible or potentially BART eligible. Yet Texas ultimately concluded that no BART-eligible source is subject to BART. Texas's determination is based in part on the unsupported selection of 0.5 dv as the threshold for contribution to visibility impairment. EPA must disapprove Texas's determination as to the sources subject to BART. Texas adopted 0.5 dv as the threshold for "contribution" to visibility impairment. Texas provided no justification for using a 0.5 dv threshold. There is no documentation in the record as to how or why Texas selected this threshold, and there is no legal support for such threshold. EPA's BART Guidelines do not authorize states automatically to use a 0.5 dv contribution threshold. Instead, the BART Guidelines state only that "any threshold that you use for determining whether a source 'contributes' to visibility impairment should not be higher than 0.5 deciviews. In the next sentence, the Guidelines instruct each state that it "should consider the number of emissions sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts." There is no evidence in the record that Texas ever conducted this analysis. Furthermore, the Guidelines conclude that "a larger number of sources causing impacts in a Class I area may warrant a lower contribution threshold." As Texas's list of 126 BART eligible sources indicates, a large number of sources impact the Class I areas in Texas and in neighboring states. Indeed, the subset of sources that screened out of BART based on individual modeling have a combined, baseline impact of nearly 10 deciviews. Thus, the situation in Texas is exactly what EPA had in mind when it noted that a contribution threshold lower than 0.5 dv may be appropriate. Had Texas followed the BART Guidelines, it may well have selected a threshold lower than 0.5 dv. Using a lower contribution threshold would change Texas's conclusion as to which sources are subject to BART because there are sources with a baseline impact just below 0.5 deciviews. EPA has a statutory responsibility to ensure that a SIP meets all applicable Clean Air Act requirements and is supported by the record. Here, Texas's use of a 0.5 dv threshold has two fatal flaws: it is not based on the analysis prescribed by the BART Guidelines, and it is not supported by any analysis whatsoever in the record. Therefore, EPA must disapprove Texas's conclusions that sources are not subject to BART, where Texas screened out sources because of a visibility impact below 0.5 deciviews.[70]

[70] This comment was submitted to a public docket (separate from the docket established for this action), in response to our December 2014 proposal (79 FR 74817, 74853-54 (Dec. 16, 2014)) to approve the subject-to-BART determinations in Texas' 2009 SIP submission and to disapprove the reasonable progress and some other elements of that SIP submission. *See* Docket Item No. EPA-R06-OAR-2014-0754-0067. We never took final action on PM

Response: EPA's BART Guidelines allow states conducting source-by-source BART determinations to exempt sources with visibility impacts as high as 0.5 dv. While we agree that a state may choose to use a lower threshold, this should be based on consideration of not only the number of sources, but the proximity to the Class I area and the potential combined visibility impacts from a group of sources. States have the discretion within the CAA, Regional Haze Rule, and BART Guidelines to set an appropriate contribution threshold considering the number of emissions sources affecting the Class I areas at issue and the magnitude of the sources' impacts.

G. Comments on EPA's Source-Specific SO_2 BART Cost Analyses

Comment: We received a large number of comments from the EGU owners covered under our proposal and environmental groups concerning various aspects of the SO_2 BART cost analyses we performed for the coal-fired EGUs. These comments included both criticisms of and support for our basic approach, the tools we used, and various individual aspects of our cost analyses. We also received Confidential Business Information (CBI) comments from the owner of one of the EGUs covering the same areas.

We also received comments from environmental groups stating that we should have required the gas-fired units that occasionally burn fuel oil to minimally switch to Ultra-Low-Sulfur Diesel (ULSD) in lieu of our proposed BART determination that these units be limited to 0.7% fuel oil by weight. These commenters argued that our estimate of the price per gallon for

BART, and did not respond to the comment. We are responding to it today because of its relevance to this final action.

ULSD was too high and that in any case, the total annual cost to make the switch is very low. They also argue that requiring the Stryker and Graham units to switch to ultra-low-sulfur diesel would significantly improve visibility.

Response: Due to the comments we received requesting a BART alternative in lieu of source-specific EGU BART determinations, we are finalizing a SO_2 trading program as an alternative to source-by-source BART. As a consequence, we believe that comments concerning the SO_2 BART cost analyses we performed on the coal-fired EGUs and these gas-fired units that occasionally burn fuel oil are no longer relevant. The trading program, by its nature, provides sources with flexibility in meeting the requirements. As a result, we expect compliance for sources to be extremely cost-effective. The program addresses both BART eligible and non-BART eligible EGUs. The combination addresses 89% of the emissions (based on 2016 annual emissions) that would have been addressed by CSAPR and, as a result, EGU emissions in Texas will be similar to emission levels anticipated in the CSAPR better than BART demonstration and will achieve greater reasonable progress than BART.

H. Comments on EPA's Modeling

1. Modeling Related to Screening out BART-eligible sources based on CALPUFF Modeling and Model Plant analysis

Comment: We received comments stating that we used an outdated version of CALPUFF and CALMET in our CALPUFF analyses and there are more recent EPA approved versions of CALPUFF and CALMET. The commenter indicated that there are more recent non-regulatory versions of CALPUFF (such as version 6.4) that include a number of technological improvements that could have been used. The commenter also indicated we did not follow USDA Forest Service Guidance that recommend using Mesocscale Model Interface Program (MMIF) for generating met fields for CALPUFF[71]. The commenter concluded that EPA's CALPUFF analysis was less reliable because of these issues.

Response: For those BART-eligible EGUs that are not covered by the BART alternative for SO_2, we are finalizing determinations that those EGUs are not subject-to-BART for NO_X, SO_2 and PM as proposed, based on the methodologies utilizing model plants and CALPUFF modeling as described in our proposed rule and BART Screening TSD. As mentioned in the BART screening TSD, we used versions (CALPUFF v5.8.4 and an existing CALMET data set that utilized CALMET v5.53a) that do not significantly differ from the current regulatory versions of CALPUFF (v5.8.5) and CALMET (v5.8.5). The current regulatory versions do include some additional bug fixes but the bugs that were fixed are not expected to significantly change the results for the modeling assessments we have done. The 2016 USDA Forest Service Guidance was not released until August of 2016 and no BART modeling was conducted by states and RPOs using MMIF. The USDA Forest Service Guidance is more germane for future SIP developments and any visibility analyses for other regulatory assessments in the future.

In considering the comment that we should use a more recent version of CALPUFF (6.4) or an earlier version 6.112, we considered the regulatory status of CALPUFF for visibility analyses and what analyses are needed to utilize an updated CALPUFF modeling system. The requirements of 40 CFR 51.112 and 40 CFR part 51, Appendix W, Guideline on Air Quality

[71] USDA Forest Service, Guidance on the Use of the Mesoscale Model Interface Program (MMIF) for Air Quality Related Values Long Range Transport Modeling Assessments (Aug. 2016).

Models (GAQM) and the BART Guidelines which refers to GAQM as the authority for using CALPUFF, provide the framework for determining the appropriate model platforms and versions and inputs to be used. Because of concern with CALPUFF's treatment of chemical transformations, which affect AQRVs, EPA has not approved the chemistry of CALPUFF's model as a "preferred" model. The use of the regulatory version is approved for increment and NAAQS analysis of primary pollutants only. Currently, CALPUFF Version 5.8, is subject to the requirements of GAQM 3.0(b) and as a screening model, GAQM 4. CALPUFF Versions 6.112 and 6.4 have not been approved by EPA for even this limited purpose. The versions of CALPUFF, version 6.112 or 6.4, that the commenter recommended could be used to provide modeling analyses of BART eligible sources that have not gone through a full regulatory review in accordance with 40 CFR part 51 Appendix W Section 3.2.2. Furthermore, the currently available information does not support the approval of these versions of the CALPUFF model for use in making BART determinations. In addition, if these versions of the model were acceptable for use, EPA would have to reconsider whether using the 98th percentile impact for determining impairment was appropriate. Therefore, EPA does not believe the use of CALPUFF version 6.112 or 6.4 is appropriate for this rulemaking. We believe we have made the appropriate choice in using CALPUFF version 5.8. For further discussion, see our Modeling RTC and the response to comments in our previous New Mexico Final FIP in 2011.[72]

Comment: We received a number of comments concerning the acceptable distances/range for which CALPUFF modeling results should be used for BART screening. A number of commenters indicated that EPA has repeatedly stated that 300 km should be the

[72] 76 FR 52388, 52431-52434 (Aug. 22, 2011).

maximum distance for CALPUFF modeling results and even cited to some past actions (several FIPs – Arkansas, Oklahoma, Montana, and New Mexico) where EPA has indicated that 300 km was the general outer distance for CALPUFF. Commenters also raised past promulgation of CALPUFF in 2003 and IWAQM guidance/reports to support the claim that 300 km is the acceptable outer range of CALPUFF. TCEQ commented we should not use CALPUFF for distances beyond 400 km. Two commenters indicated that EPA had inappropriately reported CALPUFF results for distances of 412 km and 436.1 km, well outside of 300 km. Another commenter indicated we included some model plants at distances greater than 400 km in our model plant screening analysis.

Other commenters indicated that we should use the modeling results from CALPUFF for BART screening at ranges much greater than 400 km. They stated that CALPUFF over-predicts visibility impacts at distances greater than 300 km; therefore, CALPUFF is an acceptable and conservative tool for screening BART sources at large distances from Class I areas. We received comments from several different companies (NRG, LCRA, Coleto Creek, and Luminant) that provided contractor (AECOM) analysis with opinions on the acceptable range of CALPUFF. AECOM's report for LCRA included CALPUFF modeling results for 14 Class I areas with distances out to more than 1000 km and asserted that TCEQ and EPA had utilized CALPUFF previously in screening out sources from being subject to a full BART analysis in the 2009 Texas regional haze SIP submission, our 2014 proposal, and our 2015 final action. Some comments were supportive of using CALPUFF results at distances of 400-1000 + km,[73] while others

[73] For example, see comment from Andrew Gray, Footnote 11, "For example, Texas used CALPUFF to perform BART modeling for Alcoa Inc, RN100221472 (nearest Class I area 490 km); Equistar Chemicals LP, RN 100542281 (nearest Class I area 517 km); ExxonMobil, RN102579307 and RN102450756 (nearest Class I areas 526 and 482 km, respectively); and Invista, RN104392626 and RN102663671 (nearest Class I areas 472 and 614 km,

opposed using CALPUFF beyond 300 km if the results did not screen a facility out of a full BART analysis.

A number of commenters also raised concerns with the accuracy of the CALPUFF model and several uncertainty issues related to the CALPUFF model and results from the model. We also received the comment that CALPUFF's regulatory status as a preferred model recently changed and that this change raises a question of whether CALPUFF should have been used for the Proposed Texas BART FIP.

Response: As previously discussed and included in our record for our proposal we did use direct CALPUFF modeling results of facilities out to 432 km for some very large EGU facilities (very large emissions from tall stacks). We also used CALPUFF for model plants for screening of sources beyond 360 km to a Class I Area, but the actual distance to a Class I Area was 360 km or less for each of the model plants used for screening of sources. In our 2014 proposed action[74] and the 2015 final action[75] on Texas regional haze we approved the use of CALPUFF to screen BART-eligible non-EGU sources at distances of 400 to 614 km for some sources. In those actions, we weighed the modeling results that were mostly well below 0.5 delta-dv with the potential uncertainty of CALPUFF results at these greater distances outside the

respectively). See February 25, 2009 Texas Regional Haze Plan, Chapter 9 at pages 9-9 through 9-14, available at https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html. South Dakota used CALPUFF for Big Stone's BART determination, including its impact on multiple Class I areas further than 400 km away, including Isle Royale, which is more than 600 km away. See 76 Fed. Reg. 76656. Nebraska relied on CALPUFF modeling to evaluate whether numerous power plants were subject to BART where the "Class I areas [were] located at distances of 300 to 600 kilometers or more from" the sources. See Best Available Retrofit Technology Dispersion Modeling Protocol for Selected Nebraska Utilities, p. 3. EPA Docket ID No. EPA-R07-OAR-2012-0158-0008. EPA has approved reliance on these models."

[74] 79 FR 74818 (Dec. 16, 2014).

[75] 81 FR 296 (Jan. 5, 2016).

typical range of CALPUFF in deciding how to use the results in screening of facilities. We disagree with the comment that it was inappropriate to rely on CALPUFF to screen BART-eligible EGU sources at ranges beyond 400 km and that it would not be consistent with our past approval of the BART screening modeling included in the 2009 Texas Regional Haze SIP of non-EGU BART sources.[76]

It has been asserted by the commenters that CALPUFF overestimates visibility impacts at greater distances (greater than 300/400 km) and therefore some commenters claimed that use of CALPUFF is conservative and acceptable for screening BART sources. We disagree with this comment. EPA has seen situations of both under-prediction and over-prediction at these greater distances. EPA has indicated historically that use of CALPUFF was generally acceptable at 300 km and for larger emissions sources with elevated stacks. We and FLM representatives have also allowed or supported the use of CALPUFF results beyond 400 km in some cases other than the Texas actions as pointed out by commenters.[77] EPA has a higher confidence level with results within 300 km and when analysis of impacts at Class I areas within 300 km is sufficient to inform decisions on BART screening and BART determinations, we have often limited the use of CALPUFF results to within 300 km as there are fewer questions about the suitability of the results. However, that does not preclude the use of model results for sources beyond the 300 km range with some additional consideration of relevant issues such as stack height, size of emissions, etc. As one commenter pointed out, EPA and FLM representatives have utilized CALPUFF results in a number of different situations when the range was between 300-450 km.

[76] We note that the Fifth Circuit Court of Appeals remanded the rule in its entirety. See *Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016).

[77] See comments from Andrew Gray, n 11 (which is listed in its entirety earlier in this document) citing examples of modeled impacts from sources at distances greater than 300 km in Texas, Nebraska, and South Dakota.

The model plants utilized in our model plant screening analysis were modeled at distances of 300-360 km from the Class I area. In our model plant analysis, we found that in some situations there was a difference in whether or not a source screened out based on the distance between the model plant and the Class I area. Some initial model plant runs were done at distances of 201-300 km from a Class I Area and yielded higher Q/D ratios than the same model plant evaluation with the same modeled visibility impact at 350-360 km (only 20% more than 300 km) .[78] This difference and the lower Q/D modeling for the model plant located at a greater distance from the Class I area indicated that using the model plant modeling at 300 km or less was overly conservative when we are evaluating facilities at distances of 360-600 km. Therefore, we chose the range that we thought was appropriate in the context of the distances of the sources being evaluated with that model plant. A distance of 300-360 km also fell within a range for which we have evaluated CALPUFF results a number of times and felt comfortable with using for large elevated point sources, and in most cases the comparison of Q/D ratios of the facility to model plant were not similar and the facility screened out with a significant safety margin.[79]

We note that we also had direct CALPUFF screening of some coal-fired plants out to 412 km with NOx, SO_2, and PM in our proposal. The impacts of these facilities in the proposal screening modeling were typically very large and well above the 0.5 del-dv, so even considering that there are more uncertainties at distances greater than 300 km the impacts were large enough that it was clear that these facilities would have impacts above the threshold based on impacts

[78] We did iterative modeling with the model plants to model emissions at a level that would yield a value just under the screening level of 0.5 del-dv, typically a value around 0.49 del-dv. In these model distance sensitivity runs when we used the same number of sources and stack parameters but varied the emissions to yield 98th percentile max impacts of approximately 0.49 del-dv. We found that model plants at 350-360 km range had lower resulting Q/Ds than the same model plants at 300 km, thus sources more easily screened out using model plants at 350-360 km.
[79] See our Screening of BART TSD.pdf (EPA-R06-OAR-2016-0611-0005.pdf); most sources had Q/D values on the order 30-50% of the critical Q/D from the model plant.

from the 3 pollutants.[80] The BART Guidelines indicate other models may be used on a case-by-case basis. CAMx is a photochemical modeling platform with a full chemistry mechanism that is also suited for assessing visibility impacts from single facilities/sources at longer distances where CALPUFF is more uncertain (such as distances much greater than 300 km). Texas and EPA have previously approved the use of CAMx for determining source impacts for BART screening purposes, and we also decided to supplement our CALPUFF analysis for some large coal-fired sources with CAMx modeling. Our CAMx modeling of these coal-fired sources in the proposal further supported the magnitude of the assessed impacts were well above 0.5 del-dv (NOx, SO_2, and PM) for these facilities that fell into the greater than 300 km range. We note that this screening modeling for these coal-fired facilities directly modeled with CALPUFF beyond 300 km and also modeled with CAMx is not pertinent to this final action since these coal-fired sources are participating in the SO_2 trading program and we are not finalizing subject to BART determinations for these sources.

Due to the comments we received requesting a BART alternative in lieu of source-specific EGU BART determinations, we are finalizing a SO_2 trading program as an alternative to source-by-source BART. With the NOx BART coverage from CSAPR, all the BART-eligible sources participating in the SO_2 trading program only have PM emissions that have to be assessed for screening and potential subject to PM BART determinations. As discussed elsewhere, we are approving the determination in the 2009 Texas Regional Haze SIP that PM BART emission limits are not required for any Texas EGUs.

[80] *Id.* For example, Big Brown was 404 km from WIMO and the maximum impacts with NOx, SO_2, and PM was 4.265 del-dv (over 8 times the 0.5 del-dv threshold).

We disagree with the commenter's characterization of uncertainties raised that invalidate the CALPUFF modeling results. We respond to comments raised briefly here and in our Modeling RTC. We have also responded to a number of these issues in our past FIP actions. [81]

In response to the court's 2002 finding in *American Corn Growers Ass'n. v. EPA* [82] that we failed to provide an option for BART evaluations on an individual source-by-source basis, we had to identify the appropriate analytical tools to estimate single-source visibility impacts. The 2005 BART Guidelines recommended the use of CALPUFF for assessing visibility (secondary chemical impacts) but noted that CALPUFF's chemistry was fairly simple and the model has not been fully tested for secondary formation and thus is not fully approved for secondary-formed particulate. In the preamble of the final 2005 BART guidelines, we identify CALPUFF as the best available tool for analyzing the visibility effects of individual sources, but we also recognized that it is a model that includes certain assumptions and uncertainties.[83] Evaluation of CALPUFF model performance for dispersion (no chemistry) to case studies using inert tracers has been performed.[84] It was concluded from these case studies the CALPUFF dispersion model had performed in a reasonable manner, and had no apparent bias toward over or under

[81] For example, see Arkansas FIP, 81 FR 66332, 66355- 66413 (Sept. 27, 2016) and the Response to Comments, Docket No. EPA-R06-OAR-2015-0189.
[82] *Am. Corn Growers Ass'n* v. *EPA*, 291 F.3d 1 (D.C. Cir. 2002).
[83] 70 FR 39104, 39121 (July 6, 2005).
[84] ''[M]ore recent series of comparisons has been completed for a new model, CALPUFF (Section A.3). Several of these field studies involved three-to-four hour releases of tracer gas sampled along arcs of receptors at distances greater than 50km downwind. In some cases, short-term concentration sampling was available, such that the transport of the tracer puff as it passed the arc could be monitored. Differences on the order of 10 to 20 degrees were found between the location of the simulated and observed center of mass of the tracer puff. Most of the simulated centerline concentration maxima along each arc were within a factor of two of those observed.'' 68 FR 18440, 18458 (April 15, 2003), 2003 Revisions to Appendix W, Guideline on Air Quality Models.

prediction, so long as the transport distance was limited to less than 300km.[85,86] As discussed above EPA has indicated historically that use of CALPUFF was generally acceptable at 300 km and for larger emissions sources with elevated stacks we and FLM representatives have also allowed or supported the use of CALPUFF results beyond 400 km in some cases.

In promulgating the 2005 BART guidelines, we responded to comments concerning the limitations and appropriateness of using CALPUFF.[87] In the 2005 BART Guidelines the selection of the 98th percentile value rather than the maximum value was made to address concerns that the maximum may be overly conservative and address concerns with CALPUFF's limitations.[88]

In the 2003 revisions to the Guideline on Air Quality Models, CALPUFF was added as an approved model for long range transport of primary pollutants. At that time, we considered approving CALPUFF for assessing the impact from secondary pollutants but determined that it was not appropriate in the context of a PSD review because the impact results could be used as the sole determinant in denying a permit.[89] However, the use of CALPUFF in the context of the Regional Haze rule provides results that can be used in a relative manner and are only one factor in the overall BART determination. We determined the visibility results from CALPUFF could be used as one of the five factors in a BART evaluation and the impacts should be utilized

[85] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts. Publication No. EPA–454/R–98–019. Office of Air Quality Planning & Standards, Research Triangle Park, NC. 1998.
[86] 68 FR 18440, 18458 (Apr. 15, 2003). (2003 Revisions to Appendix W, Guideline on Air Quality Models).
[87] 70 FR 39104, 39121 (July 6, 2005).
[88] *Id*., at 39121. ''Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile— a more robust approach that does not give undue weight to the extreme tail of the distribution.''
[89] 68 FR 18440 (Apr. 15, 2003).

somewhat in a relative sense because CALPUFF was not explicitly approved for full chemistry calculations.[90] We note that since the BART Guidelines were finalized in 2005 there has been more modeling with CALPUFF for BART and PSD primary impact purposes and the general community has utilized CALPUFF in the 300-450 km range many times (a number of examples were pointed out by a commenter) and EPA and FLM representatives have weighed the additional potential uncertainties with the magnitude of the modeled impacts in comparison to screening/impact thresholds on a case-by-case basis in approving the use of CALPUFF results at these extended ranges.

We disagree with the commenter's general statement that there is an acknowledged over-prediction of the CALPUFF model or an acknowledged inaccuracy at low impact levels, and that the actual visibility impacts from the BART sources are lower. The CALPUFF model can both under-predict and over-predict visibility impacts when compared to predicted visibility impacts from photochemical grid models. See our Modeling RTC for more detailed response.[91]

CALPUFF visibility modeling, performed using the regulatory CALPUFF model version and following all applicable guidance and EPA/FLM recommendations, provides a consistent tool for comparison with the 0.5 dv subject-to-BART threshold. The CALPUFF model, as

[90] 70 FR 39104, 39123-24 (July 6, 2005). ''We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range transport,'' and in discussion of using other models with more advanced chemistry, "A discussion of the use of alternative models is given in the Guideline on Air Quality in appendix W, section 3.2."

[91] For example, see Comparison of Single-Source Air Quality Assessment Techniques for Ozone, $PM_{2.5}$, other Criteria Pollutants and AQRVs, ENVIRON, September 2012; and Anderson, B., K. Baker, R. Morris, C. Emery, A. Hawkins, E. Snyder ''Proof-of-Concept Evaluation of Use of Photochemical Grid Model Source Apportionment Techniques for Prevention of Significant Deterioration of Air Quality Analysis Requirements'' Presentation for Community Modeling and Analysis System (CMAS) 2010. Annual Conference, (October 11–15, 2010) can be found at *http://www.cmascenter.org/conference/2010/agenda.cfm*.

recommended in the BART guidelines, has been used for almost every single-source BART analysis in the country and has provided a consistent basis for assessing the degree of visibility benefit anticipated from controls as one of the factors under consideration in a five factor BART analysis. Since almost all states have completed their BART analyses and have either approved SIPs or FIPs in place, there is a large set of available data on modeled visibility impacts and benefits for comparison with, and this data illuminates how those model results were utilized to screen out sources and as part of the five-factor analysis in making BART control determinations.

The regulatory status of CALPUFF was changed in the recent revisions to the Guideline on Air Quality Models (GAQM) as far as the classification of CALPUFF as a preferred model for transport of pollutants for primary impacts, not impacts based on chemistry. The recent GAQM changes do not alter the original status of CALPUFF as discussed and approved for use in the 2005 BART guidelines. The GAQM changes indicated that the change in model preferred status had no impact on the use of CALPUFF for BART.[92]

Comment: We received comments stating that we used out-of-date and unrealistic emissions for some units, which artificially inflate the actual visibility impacts. The commenters state that the data used is unrealistic due to the 2000-2004 time period selected and also due to reporting errors to CAMD. Had more recent emissions been utilized in the screening analysis,

[92] 82 FR 5182, 5196 (Jan. 17, 2017). "As detailed in the preamble of the proposed rule, it is important to note that the EPA's final action to remove CALPUFF as a preferred appendix A model in this *Guideline* does not affect its use under the FLM's guidance regarding AQRV assessments (FLAG 2010) nor any previous use of this model as part of regulatory modeling applications required under the CAA. Similarly, this final action does not affect the EPA's recommendation [See 70 FR 39104, 39122-23 (July 6, 2005)] that states use CALPUFF to determine the applicability and level of best available retrofit technology in regional haze implementation plans."

these units would have been determined to not be subject to BART by the various screening methods applied by EPA. Commenters also state that a common sense reading of the Clean Air Act, BART regulations, and BART Guidelines indicate that the "subject to BART" analysis should be based on the most recently available emission data, which EPA's subject-to-BART analysis does not use. Furthermore, the BART Guidelines do not specifically mandate the use of the 2000-2004 emission rates. Although the BART Guidelines recommend that for the purpose of screening BART-eligible sources, "States use the 24-hour average actual emission rate from the highest emitting day of the metrological period modeled," the BART Guidelines do not state that the time period analyzed must be restricted to 2000-2004. In fact, in the context of analyzing cost effective control options, the BART Guidelines recommend the use of emissions that are a "*realistic depiction* of *anticipated* annual emissions for the source."[4] And "[i]n the absence of enforceable limitations, you calculate baseline emissions based upon *continuation of past practice*."[5] EPA must also use realistic emissions when determining whether a unit causes or contributes to visibility impairment for BART. The use of 15-year old NO_X and SO_2 data for purposes of evaluating this threshold question is illogical and arbitrary and capricious.

We also received comments that doubling the annual emissions of PM was conservative and we should have potentially used maximum heat input to estimate PM emission rates for subject to BART modeling. We also received comments that the values we modeled based on CEM data may have included emission rates during upset conditions, thus the emission rates used may be larger than normal operations.

Response: We note that, as discussed elsewhere, we are not making a subject-to-BART determination for those sources covered by the SO_2 trading program. In our final rule, the relevant BART requirement for these participating units will be encompassed by BART alternatives for NOx and SO_2 such that we do not deem it necessary to finalize subject-to-BART findings for these EGUs. In addition, we are approving the determination in the 2009 TX RH SIP that none of these sources are subject to BART for PM. Therefore, comments concerning the emissions utilized in our subject to BART modeling for the sources participating in the SO_2 trading program are no longer relevant. For those BART-eligible EGUs that are not covered by the BART alternative for SO_2, we are finalizing determinations that those EGUs are not subject-to-BART for NO_X, SO_2 and PM as proposed, based on the methodologies utilizing model plants and CALPUFF modeling as described in our proposed rule and BART Screening TSD.

We disagree with the commenter and believe using emissions from the 2000-2004 period is appropriate for determining if a source is subject to BART. Our analysis for facilities followed the BART Guidelines and was consistent with the BART analyses done for all BART-eligible sources. The BART Guidelines recommend that for the purpose of screening BART-eligible sources, "States use the 24-hour average actual emission rate from the highest emitting day of the metrological period modeled" unless this rate reflects periods start-up, shutdown, or malfunction. The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization. Consistent with this guidance, we utilized the 24-hr maximum emission rate from the 2000-2004 baseline period and modeled using 2001-2003 meteorological data. We based our analysis on the CEM data from the baseline period 2000-2004 and removed what looked like questionably high values that did not occur often as they were potentially upset values. As discussed elsewhere we did review sources to determine if they installed controls during the baseline period and when that occurred we only looked at baseline emission data post controls. We received general comments that the values we used from CEM data might include upset values, but did not receive comments that indicated the values used were specifically upset values during the baseline period and should not be used. Facilities did not give us specific information to justify that the emission rates we used were not representative maximum 24-hour emission rates during the 2000-2004 period, so EPA considers the emission rates used were acceptable for the BART screening process.

We are not aware of any newly installed controls or limitations on emissions that have been put in place between the 2000-2004 baseline period and now for any of the BART-eligible sources not participating in the SO_2 trading program that would affect the potential visibility impact from the source. Furthermore, because all these sources were shown to have visibility impacts less than the 0.5 dv threshold using the maximum 24-hr actual emissions during the 2000-2004, modeling of lower emissions due to any new controls or emissions limits would also result in the same determination. We were also not provided any specific information where additional emission reductions/controls had been installed and resulted in a short-term (24-hour) maximum emission rate significantly less than modeled at any of these units.

The overall concern of the commenters was that the emissions used in the modeling resulted in some facilities being subject to a full BART analysis, but, as discussed elsewhere, we are not finalizing subject to BART determinations for the sources participating in the SO_2 trading program. For the sources not participating in the trading program, they have been screened out with our baseline emissions modeling, so underlying concerns about emissions being high/non-representative would not result in any differences to the sources being screened out from a full BART analysis.

Comment: We received comments that stated that the proposed PM BART demonstration by Texas only considered PM emissions because SO_2 and NO_X emissions were to be controlled through an alternative BART program, CAIR. Following the same type of approach, EPA in this Proposed Rule finds that CSAPR for ozone season NO_X is better than BART. However, for the screen modeling used in the development of this Proposed Rule, instead of setting the NO_X emission rate consistent with CSAPR, EPA uses the maximum 24-hour NO_X emission rates from the 2000-2004 time period. EPA ignores the continued application of CSAPR ozone season budgets that apply to EGUs in Texas. This methodology is inconsistent with past practices and overestimates cumulative conditions and facility impacts. Commenters also state that because NO_X is to be controlled by CSAPR, NO_X related haze impacts should not be considered in the screening analysis.

Response: As discussed in our response to another comment, the emission rates used in the modeling should reflect maximum 24-hour emission rates from the baseline period. CSAPR for ozone season NOx is a seasonal NOx budget but does not effectively limit short-term emission rates such that a newer maximum 24-hour emission rate can be determined. Therefore, even if it were appropriate to consider any potential reductions due to CSAPR, it is not possible to accurately model any reductions/limits due to CSAPR on a short term basis. Furthermore, emissions from a unit can vary greatly over time as the CSAPR program allows sources to meet emission budgets in a given year by using banked allowances from previous years or by purchasing allowances from other sources within or outside of the State allowing emissions from the source to exceed their annual allocation level. We also note that we were not provided specific short-term emission rate limits from commenters that were based on the installation of new controls or other reductions that were permanent reductions to short-term emission rates. Our proposal did assess if emission controls were installed during the base period and we utilized the maximum short-term emission rate from the base period after the controls were installed where applicable. Regardless of this issue, the underlying concern of the commenters was whether their facility screened out of being subject to a full BART analysis. With CSAPR coverage for NOx and the SO_2 intrastate trading program coverage for BART for all BART-eligible coal-fired EGUs, and several BART-eligible gas-fired and gas/fuel oil-fired EGUs, all the BART eligible units screen out of a full BART analysis for the pollutants not covered by trading programs, thus the chief concern that the modeling based on 2000-2004 maximum emissions and the inclusion of NOx contributed to a determination that the source was subject-to-BART, is no longer relevant.

Concerning the inclusion of NOx emissions in the screening analysis, EPA's position is that the modeling must include both pollutants (NOx and SO_2) since they both compete for ammonia. If we modeled only SO_2, all of it would convert to ammonia sulfate (based on ammonia availability) and both baseline screening impacts for SO_2 and visibility benefits from any control assessments would also be overestimated. The chemical interaction between pollutants and background species can lead to situations where the reduction of emissions of a pollutant can actually lead to an increase or inaccurate assessment of the visibility impairment, if both NOx and SO_2 are not included in CALPUFF modeling. Therefore, to fully assess the visibility benefit anticipated from the use of controls, all pollutants should be modeled together.

BART screening modeling would also include the PM emissions. BART screening is meant to be a conservative and inclusive test. We have always considered combined NOx, SO_2, and PM impacts even if the facility had NOx coverage or stringent NOx controls already installed. The BART guidelines state "You must look at SO_2, NO_X, and direct particulate matter (PM) emissions in determining whether sources cause or contribute to visibility impairment" unless emissions of these pollutants from the source are less than de minimis.[93] The BART Guidelines then provide three modeling options to determine which sources and pollutants need to be subject to BART[94]: 1) dispersion modeling to "determine an individual source's impact on visibility as a result of its emissions of SO_2, NO_X *and* direct PM emissions" ; 2) model plants to exempt individual sources with common characteristics as described in our BART Screening TSD; and 3) cumulative modeling on a pollutant by pollutant basis or for all visibility-impairing pollutants to show that no source in the State is subject to BART. The BART guidelines are clear that individual source modeling should evaluate impacts from NOx, SO_2 and PM in determining if a source is subject to BART and the pollutant-specific analyses are directed as an option to screen out the impacts of all BART sources in the State for a specific pollutant such as VOC or PM (in the case of EGUs covered by trading programs for NOx and SO_2). The BART Guidelines also state that in assessing the visibility benefits of controls "modeling should be conducted for SO_2, NO_X, *and* direct PM emissions (PM2.5 and/or PM10)."[95] In many cases a state may have only a handful of sources and impacts from more linear species (VOC or PM) may be so small that they make up a very small contribution (on the order of a 0 - 2 % of the NOx and SO_2 impacts) to the visibility impacts at a Class I Area, therefore it may be acceptable to screen out pollutants that have a minimal impact. This is not the situation with NOx, SO_2 and PM emissions from EGUs in Texas where some EGUs' PM modeled impacts were greater than 0.25 del-dv. EPA's 2006 memorandum on this is clear that you have to model both (NOx and SO_2) because

[93] 40 CFR 51 Appendix Y, Section III.A.2.
[94] 40 CFR 51 Appendix Y, Section III.A.3.
[95] 40 CFR 51 Appendix Y, Section IV.D.5 (emphasis added).

of technical and policy concerns, and also reiterated that pollutant specific analysis was for the limited situation of addressing PM when a large group of sources had BART coverage for the non-linear reacting pollutants (NOx and SO_2) through a BART alternative.[96] The BART Guidelines specifically indicate that NOx, SO_2 and PM should be modeled together when modeling BART eligible units at one facility.[97] This is similar to the BART eligibility test contemplated in the BART guidelines where if the emissions from the identified units at source exceed a potential to emit of 250 tons per year for any single visibility-impairing pollutant, the source is considered BART-eligible and may be subject to a BART review for all visibility impairing pollutants.[98]

As previously discussed the commenter's primary concern with regard to the inclusion of NOx was that this may have contributed to facilities not screening out from a full BART analysis. Because, in the final rule, trading programs constitute BART alternatives for NO_x and SO_2, the facilities that were proposed as subject to BART now screen out for the pollutants not covered by a trading program.

Comment: We received a comment from TCEQ that EPA should screen out the Newman facility based on CALPUFF modeling or use CAMx to appropriately screen Newman and determine its visibility impacts. We also received comments from the owner of Newman, EPEC, stating that the PM and SO_2 BART limits for those gas-fired units that occasionally burn fuel oil, applicable to Newman 2 and 3, of a fuel oil sulfur content of 0.7% is acceptable, and that

[96] EPA Memorandum from Joseph W. Paisie OAQPS to Kay Prince EPA Region 4, "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations", July 19, 2006.
[97] 40 CFR 51 Appendix Y, Section III.A.3.
[98] See first example in 40 CFR 51 Appendix Y, Section II.A.4.

Newman 4 is restricted to burn only natural gas. EPEC has maintained on-site diesel fuel oil with a lesser sulfur content as emergency backup fuel for testing for preparedness purposes, and in the unlikely scenario of a natural gas curtailment event or other situation that may compromise the steady flow of the primary pipeline quality natural gas fuel supply. EPEC also notes that these units are only permitted to operate 876 hours per year.

Response: Based upon the comments we received requesting a BART alternative in lieu of source-specific EGU BART determinations, we are finalizing a SO_2 trading program as an alternative to source-by-source BART. We are not finalizing subject-to-BART determinations for BART eligible sources covered by the BART alternative for SO_2 and NOx. In our final rule, the relevant BART requirement for these participating units, including the BART-eligible Newman units, will be satisfied by BART alternatives for NOx and SO_2 such that we do not deem it necessary to finalize subject-to-BART findings for these EGUs. In addition, we are approving a determination that none of these sources are subject to BART for PM. Therefore, we do not find it necessary to respond to the merits of comments concerning screening modeling for this source, because the outcome of that modeling is not dispositive to the source's inclusion in the BART alternative or its allowance thereunder. See discussion above for assessment of previous CAMx PM screening (Texas 2009 RH SIP) where the Newman source was included in Group 2 with a number of other sources and screened out from being subject to BART for PM.

Comment: We received comments that some of the stack parameters were incorrect at facilities in our CALPUFF and CAMx modeling. New stack height, diameter, velocity values were given for some units.

Response: We reviewed the information provided and note that some facilities gave contradicting data within their comments. For those facilities for which we are relying on modeling to determine they are not subject to BART, we have evaluated potential changes where we may have had an inaccurate number in our proposal modeling. We have determined that the impacts from changes to stack parameters would be minimal and not change our current assessment and decisions.

5. Modeling Related to whether Coal-fired Sources are Subject to BART

Comment: We received comments on the CALPUFF and CAMx modeling utilized to determine which coal-fired EGUs are subject to BART. These included comments concerning emissions inputs, the metrics used, the post-processing methodology, and the model performance.

Response: Due to the comments we received requesting a BART alternative in lieu of source-specific EGU BART determinations, we are finalizing a SO_2 trading program as an alternative to source-by-source BART. This trading program includes participation of all BART-eligible coal-fired EGUs such that we do not deem it necessary to finalize subject-to-BART findings for these EGUs except for PM emissions. As a consequence, we believe that it is not necessary to respond to the merits of comments concerning modeled baseline visibility impacts using CALPUFF or CAMx and determination of which coal-fired sources are subject to BART. In this final action we are approving the determination in the Texas RH SIP that all EGU sources screen out of BART for PM. We are also finalizing the determination that all BART-eligible

EGUs not participating in the trading program screen out of BART for NOx, SO_2 and PM based on upon CALPUFF modeling (direct source and Model Plant). We address all comments pertinent to the use of CALPUFF (direct source and Model Plant) for BART screening for these sources in other responses to comments. We note that the comments expressing concerns about CALPUFF modeling were associated with facilities that did not screen out from a full subject to BART analysis. Since we have determined that no EGU sources are now subject to BART and a source-specific BART control analysis for pollutants not covered by a BART alternative, the specific concerns raised by commenters about being determined to be subject to a BART control analysis because of emissions inputs used, metrics used, etc. are not relevant to this final action. See the Modeling RTC document for the entirety of the modeling comments and our responses.

Comment: The 0.5 dv threshold used by EPA in its proposed determinations based on CAMx modeling of what sources are subject to BART is too low, given the uncertainties in the CAMx modeling methods used to quantify the visibility impacts of sources.

Response: In our proposed action, we utilized CAMx modeling to evaluate visibility impacts from BART-eligible sources that include BART eligible coal-fired EGUs. Due to the comments we received requesting a BART alternative in lieu of source-specific EGU BART determinations, we are finalizing a SO_2 trading program as an alternative to source-by-source BART. This trading program includes participation of all BART-eligible coal-fired EGUs such that we do not deem it necessary to finalize subject-to-BART findings for these sources except for PM emissions.

In this final action the only CAMx modeling we are relying upon is CAMx modeling performed for TCEQ in screening of EGU emissions of PM that was included in TCEQ's 2009 SIP. Our approval of the CAMx PM screening of EGUs is based on the original CENRAP modeling datasets, agreed modeling protocols and Texas' use of the 0.5 del-dv to screen sources as agreed upon by TCEQ in 2007. Any potential concerns with CAMx bias were considered in 2007 and TCEQ, EPA and FLM representatives agreed to the approach of using 0.5 del-dv to screen groups of sources using CAMx modeling. We note that the BART guidelines specifically state that "as a general matter, any threshold that you use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 deciviews."[99] Furthermore, our action on the PM BART determinations in the 2009 Texas SIP submittal would not be any different had we used a higher threshold since all sources screened out based on the use of the 0.5 dv threshold. Since we are not relying on the CAMx modeling we had performed for our proposal, any comments concerning the use of this modeling are not pertinent to this final action and it is not necessary to respond to the merits of those comments.

6. Modeling Related to Visibility Benefit of Sources Subject-to-BART

Comment: We received comments on the CALPUFF and CAMx modeling utilized to estimate the visibility benefits of controls. These included comments concerning the emissions inputs, the metrics used, the post-processing methodology, and the model performance.

Response: Based on the comments we received requesting a BART alternative in lieu of source-specific EGU BART determinations, we are finalizing a SO_2 trading program as an alternative to source-by-source BART. This trading program includes participation of all BART-

[99] 40 CFR 51 Appendix Y, Section III.A.1.

eligible coal-fired EGUs and a number of BART-eligible gas or gas/fuel oil-fired EGUs. It also includes a number of non-BART eligible EGUs. The combination of the source coverage for this program, the total allocations for EGUs covered by the program, and recent and foreseeable emissions from EGUs not covered by the program will result in future EGU emissions in Texas that are similar to the SO_2 emission levels forecast in the 2012 better-than-BART demonstration for Texas EGU emissions assuming CSAPR participation. We are not finalizing our evaluation of whether individual sources are subject to BART. As a consequence, we believe that it is not necessary to respond to the merits of comments concerning source-specific visibility benefits of controls on these units, because we are not finalizing requirements based on those controls.

I. Comments on Affordability and Grid Reliability

Comment: We received comments from the State, EGU owners covered under our proposal and environmental groups concerning whether our proposal would cause EGUs to retire and thus cause grid reliability issues. These comments included both criticisms of and support for our proposed position. Texas, in particular, stated that recent ERCOT studies have raised concerns that several units in Texas will no longer be economically viable if required to install capital intensive controls. They also indicated that EPA's IPM modeling supports this conclusion. Texas believed that if units shutdown with little notice it could cause reliability concerns.

Response: EPA takes very seriously concerns about grid reliability. We are finalizing a SO_2 trading program as an alternative to source-by-source BART. We believe the program we have designed will help address reliability concerns because it does not require installation of capital intensive controls and will provide much more flexibility to sources than the source by source compliance we proposed. In fact, aggregate emissions of the covered sources in 2016 were below the level called for by the trading program. In addition, the supplemental allowance pool is expected to provide additional flexibility to allow sources to run, if necessary, in an emergency. We believe that it is not necessary to respond on the merits to specific comments concerning the impacts to grid reliability related to the requirements of the proposed source-specific controls, because we are not finalizing those requirements.

V. SO_2 Trading Program and Its Implications for Interstate Visibility Transport, EGU BART, and Reasonable Progress

The Regional Haze Rule provides each state with the flexibility to adopt an allowance trading program or other alternative measure instead of requiring source-specific BART controls, so long as the alternative measure is demonstrated to achieve greater reasonable progress than BART. As discussed in Section III.A.3 above, based principally on comments submitted by the State of Texas during the comment period urging us to consider as a BART alternative the concept of system-wide emission caps using CSAPR allocations as part of an intrastate trading program,[100] we are acknowledging the State's preference and exercising our authority to promulgate a BART alternative for SO_2 for certain Texas EGUs. The combination of the source coverage for this program, the total allocations for EGUs covered by the program, and recent and foreseeable emissions from EGUs not covered by the program will result in future EGU emissions in Texas that are similar to what was forecast in the 2012 better than BART demonstration for Texas EGU emissions assuming CSAPR participation.

[100] *See* Docket Item No. EPA-R06-OAR-2016-0611-0070, p. 3.

A. Background on the CSAPR as an Alternative to BART Concept

In 2012, the EPA amended the Regional Haze Rule to provide that participation by a state's EGUs in a CSAPR trading program for a given pollutant – qualifies as a BART alternative for those EGUs for that pollutant.[101] In promulgating this CSAPR-better-than-BART rule (also referred to as "Transport Rule as a BART Alternative"), the EPA relied on an analytic demonstration based on an air quality modeling study[102] showing that CSAPR implementation meets the Regional Haze Rule's criteria for a demonstration of greater reasonable progress than BART. In the air quality modeling study conducted for the 2012 analytic demonstration, the EPA projected visibility conditions in affected Class I areas[103] based on 2014 emissions projections for two control scenarios and on the 2014 base case emissions projections.[104] One control scenario represents "Nationwide BART" and the other represents "CSAPR+BART-elsewhere." In the base case, neither BART controls nor the EGU SO_2 and NOx emissions reductions attributable to CSAPR were reflected. To project emissions under CSAPR, the EPA assumed that the geographic scope and state emissions budgets for CSAPR would be implemented as finalized and amended in 2011 and 2012.[105] The results of that analytic demonstration based on

[101] 40 CFR 51.308(e)(4); *see also generally* 77 FR 33641 (June 7, 2012). Legal challenges to the CSAPR-better-than-BART rule from conservation groups and other petitioners are pending. *Utility Air Regulatory Group v. EPA*, No. 12-1342 (D.C. Cir. filed August 6, 2012).

[102] *See* Technical Support Document for Demonstration of the Transport Rule as a BART Alternative, Docket ID No. EPA-HQ-OAR-2011-0729-0014 (December 2011) (2011 CSAPR/BART Technical Support Document), and memo entitled "Sensitivity Analysis Accounting for Increases in Texas and Georgia Transport Rule State Emissions Budgets," Docket ID No. EPA-HQ-OAR-2011-0729-0323 (May 29, 2012), both available in the docket for this action.

[103] The EPA identified two possible sets of ''affected Class I areas'' to consider for purposes of the study and found that implementation of CSAPR met the criteria for a BART alternative whichever set was considered. *See* 77 FR 33641, 33650 (June 7, 2012).

[104] For additional detail on the 2014 base case, *see* the CSAPR Final Rule Technical Support Document, available in the docket for this action.

[105] CSAPR was amended three times in 2011 and 2012 to add five states to the seasonal NO_X program and to

this air quality modeling passed the two-pronged test set forth at 40 CFR 51.308(e)(3). The first prong ensures that the alternative program will not cause a decline in visibility at any affected Class I area. The second prong ensures that the alternative program results in improvements in average visibility across all affected Class I areas as compared to adopting source-specific BART. Together, these tests ensure that the alternative program provides for greater visibility improvement than would source-specific BART.

For purposes of the 2012 analytic demonstration that CSAPR as finalized and amended in 2011 and 2012 provides for greater reasonable progress than BART, the analysis included Texas EGUs as subject to CSAPR for SO_2 and annual NOx (as well as ozone-season NOx). CSAPR's emissions limitations are defined in terms of emissions "budgets" for the collective emissions from affected EGUs in each covered state. Sources have the ability to purchase allowances from sources outside of the state, so total projected emissions for a state may, in some cases, exceed the state's emission budget, but aggregate emissions from all sources in a state should remain lower than or equal to the state's "assurance level." The final emission budget under CSAPR for Texas was 294,471 tons per year for SO_2, including 14,430 tons of allowances available in the new unit set aside.[106] The State's "assurance level" under CSAPR was 347,476 tons.[107] Under

increase certain state budgets. 76 FR 80760 (Dec. 27, 2011); 77 FR 10324 (Feb. 21, 2012); 77 FR 34830 (June 12, 2012). The CSAPR-better-than-BART final rule reflected consideration of these changes to CSAPR.

[106] Units that are subject to CSAPR but that do not receive allowance allocations as existing units are eligible for a new unit set aside (NUSA) allowance allocation. NUSA allowance allocations are a batch of emissions allowances that are reserved for new units that are regulated by the CSAPR, but weren't included in the final rule allocations. The NUSA allowance allocations are removed from the original pool of regional allowances, and divided up amongst the new units, so as not to exceed the emissions cap set in the CSAPR. Each calendar year, EPA issues three pairs of preliminary and final notices of data availability (NODAs), which are determined and recorded in two "rounds" and are published in the Federal Register. In any year, if the NUSA for a given CSAPR state and program does not have enough new units after completion of the 2nd round, the remaining allowances are allocated to existing CSAPR-affected units.

[107] See 40 CFR 97.710 for state SO_2 Group 2 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

CSAPR, the projected SO_2 emissions from the affected Texas EGUs in the CSAPR + BART-elsewhere scenario were 266,600 tons per year. In a 2012 sensitivity analysis memo, EPA conducted a sensitivity analysis that confirmed that CSAPR would remain better-than-BART if Texas EGU emissions increased to approximately 317,100 tons.[108]

As introduced in Section I.C, in the EPA's final response to the D.C. Circuit's remand of certain CSAPR budgets, we finalized the withdrawal of the requirements for Texas' EGUs to participate in the annual SO_2 and NOx trading programs and also finalized our determination that the changes to the geographic scope of the CSAPR trading programs resulting from the remand response do not affect the continued validity of participation in CSAPR as a BART alternative. This determination that CSAPR remains a viable BART alternative despite changes in geographic scope resulting from EPA's response to the CSAPR remand was based on a sensitivity analysis of the 2012 analytic demonstration used to support the original CSAPR as better-than-BART rulemaking. A full explanation of the sensitivity analysis is included in the remand response proposal and final rule.[109]

B. Texas SO_2 Trading Program

[108] For the projected annual SO_2 emissions from Texas EGUs See Technical Support Document for Demonstration of the Transport Rule as a BART Alternative, Docket ID No. EPA–HQ–OAR–2011– 0729–0014 (December 2011) (2011 CSAPR/BART Technical Support Document), available in the docket for this action. at table 2–4. Certain CSAPR budgets were increased after promulgation of the CSAPR final rule (and the increases were addressed in the 2012 CSAPR/BART sensitivity analysis memo. See memo entitled ''Sensitivity Analysis Accounting for Increases in Texas and Georgia Transport Rule State Emissions Budgets,'' Docket ID No. EPA–HQ–OAR–2011–0729–0323 (May 29, 2012), available in the docket for this action. The increase in the Texas SO_2 budget was 50,517 tons which, when added to the Texas SO_2 emissions projected in the CSAPR + BART-elsewhere scenario of 266,600 tons, yields total potential SO_2 emissions from Texas EGUs of approximately 317,100 tons.

[109] 81 FR 78954 (Nov. 10, 2016) and final action signed September 21, 2017 available at *regulations.gov* in Docket No. EPA-HQ-OAR-2016-0598

Texas is no longer in the CSAPR program for annual SO_2 emissions and accordingly cannot rely on CSAPR as a BART alternative for SO_2 under 51.308(e)(4).[110] Therefore, informed by the TCEQ comments, we are proceeding to address the SO_2 BART requirement for coal-fired, some gas-fired, and some gas/fuel oil-fired units under a BART alternative, which we are justifying according to the demonstration requirements under 51.308(e)(2).

1. Identification of Sources Participating in the Trading Program

Under 51.308(e)(2), a State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. At the same time, the Texas trading program should be designed so as not to interfere with the validity of existing SIPs in other states that have relied on reductions from sources in Texas. As discussed elsewhere, the Texas trading program is designed to provide the measures that are needed to address interstate visibility transport requirements for several NAAQS and to be part of the long-term strategy needed to meet the reasonable progress requirements of the Regional Haze Rule.[111] To meet all of these goals, the trading program must not only be inclusive of all BART-eligible sources that are treated as satisfying the BART requirements through participation in a BART alternative, but must also include additional emission sources such that the trading program as a whole can be shown to

[110] See final action signed September 21, 2017 available at *regulations.gov* in Docket No. EPA-HQ-OAR-2016-0598

[111] EPA is not determining at this time that this final action fully resolves the EPA's outstanding obligations with respect to reasonable progress that resulted from the Fifth Circuit's remand of our reasonable progress FIP. We intend to take future action to address the Fifth Circuit's remand.

both achieve greater reasonable progress than would be achieved through the installation and operation of BART, and achieve the emission reductions relied upon by other states during consultation and assumed by other states in their own regional haze SIPs, including their reasonable progress goals for their Class I areas.

The identification of EGUs in the trading program necessarily begins with the list of BART-eligible EGUs for which we intend to address the BART requirements through a BART alternative. As discussed elsewhere, we determined that several BART-eligible gas-fired and gas/oil-fired EGUs are not subject-to-BART for NOx, SO_2, and PM, therefore those BART-eligible sources are not included in the trading program. The table below lists those BART-eligible EGUs identified for participation in the trading program.

Table 4. BART-Eligible EGUs Participating in the Trading Program

Facility	**Unit**
Big Brown (Luminant)	1
Big Brown (Luminant)	2
Coleto Creek (Dynegy[112])	1
Fayette (LCRA)	1
Fayette (LCRA)	2
Graham (Luminant)	2
Harrington Station (Xcel)	061B
Harrington Station (Xcel)	062B
J T Deely (CPS Energy)	1
J T Deely (CPS Energy)	2

[112] Dynegy purchased the Coleto Creek power plant from Engie in February, 2017. Note that Coleto Creek may still be listed as being owned by Engie in some of our supporting documentation which was prepared before that sale.

Martin Lake (Luminant)	1
Martin Lake (Luminant)	2
Martin Lake (Luminant)	3
Monticello (Luminant)	1
Monticello (Luminant)	2
Monticello (Luminant)	3
Newman (El Paso Electric)	2
Newman (El Paso Electric)	3
Newman (El Paso Electric)	4
O W Sommers (CPS Energy)	1
O W Sommers (CPS Energy)	2
Stryker Creek (Luminant)	ST2
WA Parish (NRG)	WAP4
WA Parish (NRG)	WAP5
WA Parish (NRG)	WAP6
Welsh Power Plant (AEP)	1
Welsh Power Plant (AEP)	2
Wilkes Power Plant (AEP)	1
Wilkes Power Plant (AEP)	2
Wilkes Power Plant (AEP)	3

For a BART alternative that includes an emissions trading program, the applicability provisions must be designed to prevent any significant potential shifting within the state of production and emissions from sources in the program to sources outside the program. Shifting would be logistically simplest among units in the same facility, because they are under common management and have access to the same transmission lines. In addition, since a coal-fired EGU to which electricity production could shift would have a relatively high SO_2 emission rate (compared to a gas-fired EGU), such shifting could also shift substantive amounts of SO_2 emissions. To prevent any significant shifting of generation and SO_2 emissions from participating sources to non-participating sources within the same facility, coal-fired EGUs that are not BART-eligible but are co-located with BART-eligible EGUs have been included in the program. While Fayette Unit 3, WA Parish Unit 8 (WAP8), and J K Spruce Units 1 and 2 were identified as coal-fired units that are not BART-eligible but are co-located with BART-eligible EGUs, these units have scrubbers installed to control SO_2 emissions such that a shift in generation from the participating units to these units would not result in a significant increase in emissions. Fayette Unit 3 has a high performing scrubber similar to the scrubbers on Fayette Units 1 and 2,[113] and has a demonstrated ability to maintain SO_2 emissions at or below 0.04 lbs/MMBtu.[114] We find that any shifting of generation from the participating units at the facility to Fayette Unit 3 would result in an insignificant shift of emissions. The scrubber at Parish Unit 8 maintains an emission rate four to five times lower than the emission rate of the other coal-fired units at the facility (Parish Units 5,6, and 7) that are uncontrolled.[115] Shifting of generation from the participating units at the Parish facility to Parish Unit 8 would result in a decrease in overall emissions from the source. Similarly, J K Spruce Units 1 and 2 have high performing scrubbers and emit at emission rates much lower than the co-located BART-eligible coal-fired units (J T Deely Units 1 and 2).[116] In addition, because these units not covered by the program are on average better controlled for SO_2 than the covered sources and emit far less SO_2 per unit of

[113] See the BART FIP TSD, available in the docket for this action (Document Id: EPA-R06-OAR-2016-0611-0004), for evaluation of the performance of scrubbers on Fayette Units 1 and 2.
[114] The annual average emission rate for 2016 for this unit was 0.01 lb/MMBtu.
[115] Parish Units 5 and 6 are coal-fired BART-eligible units. Parish Unit 7 is not BART-eligible, but is a co-located coal-fired EGU. Unlike Parish Unit 8, these three units do not have an SO_2 scrubber installed.
[116] The annual average emission rate for 2016 for J K Spruce Units 1 and 2 was 0.03 lb/MMBtu and 0.01 lb/MMBtu, respectively. The annual average emission rate for 2016 for J T Deely Units 1 and 2 was 0.52 lb/MMBtu and 0.51 lb/MMBtu, respectively.

energy produced, we conclude that in general, based on the current emission rates of the EGUs, should a portion of electricity generation shift to those units not covered by the program, the net result would be a decrease in overall SO_2 emissions, as these non-participating units are on average much better controlled. Relative to current emission levels, should participating units increase their emissions rates and decrease generation to comply with their allocation, emissions from non-participating units may see a small increase. Therefore, we have not included Fayette Unit 3, WA Parish Unit 8 (WAP8), and J K Spruce Units 1 and 2 in the trading program. The table below lists those coal-fired units that are co-located with BART-eligible units that have been identified for inclusion in the trading program.

Table 5. Coal-fired EGUs Co-located with BART-Eligible EGUs and Participating in the Trading Program

Facility	**Unit**
Harrington Station (Xcel)	063B
WA Parish (NRG)	WAP7
Welsh Power Plant (AEP)	3

In addition to these sources, we also evaluated other EGUs for inclusion in the trading program based on their potential to impact visibility at Class I areas. Addressing emissions from sources with the largest potential to impact visibility is required to make progress towards the goal of natural visibility conditions and to address emissions that may otherwise interfere with measures required to protect visibility in other states. EPA, States, and RPOs have historically used a Q/D analysis to identify those facilities that have the potential to impact visibility at a Class I area based on their emissions and distance to the Class I area. Where,

1. Q is the annual emissions in tons per year (tpy), and
2. D is the nearest distance to a Class I Area in kilometers (km)

We used a Q/D value of 10 as a threshold for identification of facilities that may impact air visibility at Class I areas and could be included in the trading program in order to meet the goals of achieving greater reasonable progress than BART and limiting visibility transport. We selected this value of 10 based on guidance contained in the BART Guidelines, which states:

> Based on our analyses, we believe that a State that has established 0.5 deciviews as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tpy of NOx or SO_2 (or combined NOx and SO_2), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tpy of NOx or SO_2 (or combined NOx and SO_2) that are located more than 100 kilometers from any Class I area.[117]

The approach described above corresponds to a Q/D threshold of 10. This approach has also been recommended by the Federal Land Managers' Air Quality Related Values Work Group (FLAG)[118] as an initial screening test to determine if an analysis is required to evaluate the potential impact of a new or modified source on air quality related value (AQRV) at a Class I area. For this purpose, a Q/D value is calculated using the combined annual emissions in tons per

[117] See 40 CFR part 51, App. Y, § III (How to Identify Sources "Subject to BART").
[118] Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report—Revised (2010) Natural Resource Report NPS/NRPC/NRR—2010/232, October 2010. Available at http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf

year of (SO_2, NOx, PM10, and sulfuric acid mist (H_2SO_4) divided by the distance to the Class I area in km. A Q/D value greater than 10 requires a Class I area AQRV analysis.[119]

We considered the results of an available Q/D analysis based on 2009 emissions to identify facilities that may impact air visibility at Class I areas.[120] The table below summarizes the results of that Q/D analysis for EGU sources in Texas with a Q/D value greater than 10 with respect to the nearest Class I area to the source.

Table 6. Q/D Analysis for Texas EGUs (Q/D Greater Than 10, 2009 annual emissions)

Facility	**Maximum Q/D**
H.W. Pirkey (AEP)	35.8
Big Brown (Luminant)	182.9
Sommers-Deely (CPS)	56.9
Coleto Creek (Dynegy)	46.0
Fayette (LCRA)	61.0
Gibbons Creek (TMPA)	30.8
Harrington Station (XCEL)	107.8
San Miguel	32.9
Limestone (NRG)	85.1
Martin Lake (Luminant)	367.4
Monticello (Luminant)	425.4
Oklaunion (AEP)	85.0
Sandow (Luminant)	63.0
Tolk Station (XCEL)	148.5
Twin Oaks	14.2
WA Parish (NRG)	84.3
Welsh (AEP)	230.1

[119] We also note that TCEQ utilized a Q/D threshold of 5 in its analysis of reasonable progress sources in the 2009 Texas Regional Haze SIP. See Appendix 10-1.
[120] See the TX RH FIP TSD that accompanied our December 2014 Proposed action 79 FR 74818 (Dec 16, 2014) and 2009statesum_Q_D.xlsx available in the docket for that action.

Based on the above Q/D analysis, we identified additional coal-fired EGUs for participation in the SO_2 trading program due to their emissions, proximity to Class I areas, and potential to impact visibility at Class I areas. While Gibbons Creek is identified by the Q/D analysis, the facility does not include any BART-eligible EGUs and has installed very stringent controls such that current emissions are approximately 1% of what they were in 2009.[121] Therefore, we do not consider Gibbons Creek to have significant potential to impact visibility at any Class I area and do not include it in the trading program. The Twin Oaks facility, consisting of two units, is also identified as having a Q/D greater than 10. However, the Q/D for this facility is significantly lower than that of the other facilities, the facility does not include any BART-eligible EGUs, and the estimated Q/D for an individual unit would be less than 10. We do not consider the potential visibility impacts from these units to be significant relative to the other coal-fired EGUs in Texas with Q/Ds much greater than 10 and do not include it in the trading program. The Oklaunion facility consists of one coal-fired unit that is not BART-eligible. Annual emissions of SO_2 in 2016 from this source were 1,530 tons, less than 1% of the total annual emissions for EGUs in the state. We have determined that the most recent emissions from this facility are small relative to other non-BART units included in the program and we have not included Oklaunion in the trading program. Finally, San Miguel is identified as having a Q/D greater than 10. The San Miguel facility consists of one coal-fired unit that is not BART-eligible. In our review of existing controls at the facility performed as part of our action to address the remaining regional haze obligations for Texas, we found that the San Miguel facility has upgraded its SO_2 scrubber system to perform at the highest level (94% control efficiency)

[121] 2016 annual SO_2 emissions were only 138 tons compared to 11,931 tons in 2009.

that can reasonably be expected based on the extremely high sulfur content of the coal being burned, and the technology currently available.[122] Since completion of all scrubber upgrades,[123] emissions from the facility on a 30-day boiler operating day[124] rolling average basis have remained below 0.6 lb/MMBtu and the 2016 annual average emission rate was 0.44 lb/MMBtu. Therefore, we have determined that the facility is well controlled and have not included San Miguel in the trading program. Other coal-fired EGUs in Texas that are not included in the trading program either had Q/D values less than 10 based on 2009 emissions or were not yet operating in 2009. New units beginning operation after 2009 would be permitted and constructed using emission control technology determined under either BACT or LAER review, as applicable and we do not consider the potential visibility impacts from these units to be significant relative to those coal-fired EGUs participating in the program. See Table 10 and accompanying discussion in the section below for additional information on coal-fired EGUs not included in the trading program. The table below lists the additional units identified by the Q/D analysis described above as potentially significantly impacting visibility and are included in the trading program. We note that all of the other coal-fired units identified for inclusion in the trading program due to their BART-eligibility or by the fact that they are co-located with BART-eligible coal units would also be identified for inclusion in the trading program if the Q/D analysis were applied to them.

[122] 79 FR 74818 (Dec. 16, 2014).
[123] San Miguel Electric Cooperative FGD Upgrade Program Update, URS Corporation, June 30, 2014. Available in the docket for our December 2014 Proposed action, 79 FR 74818 (Dec 16, 2014) as "TX166-008-066 San Miguel FGD Upgrade Program."
[124] A boiler operating day (BOD) is 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. See 70 FR 39172 (July 6, 2005).

Table 7. Additional Units Identified for Inclusion in the Trading Program

Facility	**Unit**
H.W. Pirkey (AEP)	1
Limestone (NRG)	1
Limestone (NRG)	2
Sandow (Luminant)	4
Tolk (Xcel)	171B
Tolk (Xcel)	172B

As discussed in more detail below, the inclusion of all of these identified sources (Tables 4, 5, and 7 above) in an intrastate SO_2 trading program will achieve emission levels that are similar to original projected participation by all Texas EGUs in the CSAPR program for trading of SO_2 and achieve greater reasonable progress than BART. In addition to being a sufficient alternative to BART, the trading program secures reductions consistent with visibility transport requirements and is part of the long-term strategy to meet the reasonable progress requirements of the Regional Haze Rule.[125] The combination of the source coverage for this program, the total allocations for EGUs covered by the program, and recent and foreseeable emissions from EGUs not covered by the program will result in future EGU emissions in Texas that on average will be no greater than what was forecast in the 2012 better-than-BART demonstration for Texas EGU emissions assuming CSAPR participation.

2. Texas SO_2 Trading Program as a BART Alternative

[125] EPA is not determining at this time that this final action fully resolves the EPA's outstanding obligations with respect to reasonable progress that resulted from the Fifth Circuit's remand of our reasonable progress FIP. We intend to take future action to address the Fifth Circuit's remand.

40 CFR 51.308(e)(2) contains the required plan elements and analyses for an emissions trading program or alternative measure designed as a BART alternative.

As discussed above, consistent with our proposal, we are finalizing our list of all BART-eligible sources, in Texas, which serves to satisfy 51.308(e)(2)(i)(A).

This action includes a list of all EGUs covered by the trading program, satisfying the first requirement of 51.308(e)(2)(i)(B). All BART-eligible coal-fired units, some additional coal-fired EGUs, and some BART-eligible gas-fired and oil-and-gas-fired units are covered by the alternative program.[126] This coverage and our determinations that the BART-eligible gas-fired and oil-and-gas-fired EGUs not covered by the program are not subject-to-BART for NOx, SO_2 and PM satisfy the second requirement of 51.308(e)(2)(i)(B).

Regarding the requirements of 40 CFR 51.308(e)(2)(i)(C), we are not making determinations of BART for each source subject to BART and covered by the program. The demonstration for a BART alternative does not need to include determinations of BART for each source subject to BART and covered by the program when the "alternative measure has been designed to meet a requirement other than BART." The Texas trading program meets this condition, as discussed elsewhere, because it has been designed to meet multiple requirements other than BART. This BART alternative extends beyond all BART-eligible coal-fired units to include a number of additional coal-fired EGUs, and some BART-eligible gas-fired and oil-and-gas-fired units, capturing the majority of emissions from EGUs in the State and is designed to provide the measures that are needed to address interstate visibility transport requirements for several NAAQS. This is because for all sources covered by the Texas SO_2 trading program, those sources' CSAPR allocations for SO_2 are incorporated into this finalized BART alternative,

[126] See Table 3 above for list of participating units and identification of BART-eligible participating units.

and the BART FIP obtains more emission reductions of SO_2 and NOx than the level of emissions reductions relied upon by other states during consultation and assumed by other states in their own regional haze SIPs including their reasonable progress goals for their Class I areas. This BART alternative, addressing emissions from both BART eligible and non-BART eligible sources, that in combination provides for greater reasonable progress than BART, is also designed to be part of the long-term strategy needed to meet the reasonable progress requirements of the Regional Haze Rule, which remain outstanding after the remand of our reasonable progress FIP by the Fifth Circuit Court of Appeals. Since the time of our January 4, 2017 proposal on BART, we note that the Fifth Circuit Court of Appeals has remanded without vacatur our prior action on the 2009 Texas Regional Haze SIP and part of the Oklahoma Regional Haze SIP.[127] We contemplate that future action on this remand, including action that may merge with new development of SIP revisions by the State of Texas as contemplated in its request for the SO_2 BART alternative, will bring closure to the reasonable progress requirement. For these reasons, we find that it is not necessary for us to make determinations of BART for each source subject to BART and covered by the program. In this context, 51.308(e)(2)(i)(C) provides that we may "determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate." In this action, we are relying on the determinations of the best system of continuous emission control technology and associated emission reductions for EGUs as was used in our 2012 determination that showed that CSAPR as finalized and amended in 2011 and 2012 achieves more reasonable progress than BART. These determinations were based on category-wide information.

[127] *Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016).

Regarding the requirement of 40 CFR 51.308(e)(2)(i)(D), our analysis is that the Texas trading program will effectively limit the aggregate annual SO_2 emissions of the covered EGUs to be no higher than the sum of their allowances. As discussed elsewhere, the average total annual allowance allocation for covered sources is 238,393 tons and an additional 10,000 tons for the Supplemental Allowance pool. In addition, while the Supplemental Allowance pool may grow over time as unused supplemental allowances remain available and allocations from retired units are placed in the supplemental pool, the total number of allowances that can be allocated in a control period from the supplemental pool is limited to a maximum 54,711 tons plus the amount of any allowances placed in the pool that year from retired units and corrections. Therefore, annual average emissions for the covered sources will be less than or equal to 248,393 tons with some year to year variability constrained by the number of banked allowances and number of allowances that can be allocated in a control period from the supplemental pool. The projected SO_2 emission reduction that will be achieved by the program, relative to any selected historical baseline year, is therefore the difference between the aggregate historical baseline emissions of the covered units and the average total annual allocation. For example, the aggregate 2014 SO_2 emissions of the covered EGUs were 309,296 tons per year, while the average total annual allocation for the covered EGUs is 248,393 tons/year.[128] Therefore, compared to 2014 emissions, the Texas trading program is projected to achieve an average reduction of approximately 60,903 tons per year.[129] We note that the trading program allows

[128] Texas sources were subject to CSAPR in 2015 and 2016 but are no longer subject to CSAPR. We therefore select 2014 as the appropriate most recent year for this comparison.
[129] We note that for other types of alternative programs that might be adopted under 40 CFR 51.308(e)(2), the analysis of achievable emission reductions could be more complicated. For example, a program that involved economic incentives instead of allowances or that involved interstate allowance trading would present a more complex situation in which achievable emission reductions could not be calculated simply be comparing aggregate baseline emissions to aggregate allowances.

additional sources to opt-in to the program. Should sources choose to opt-in in the future, the average total annual allocation could increase up to a maximum of 289,740. For comparison, the aggregate 2014 SO_2 emissions of the covered EGUs including all potential opt-ins were 343,425 tons per year. Therefore, compared to 2014 emissions, the Texas trading program including all potential opt-ins is projected to achieve an average reduction of approximately 53,685 tons per year.

Regarding the requirement of 40 CFR 51.308(e)(2)(i)(E), the BART alternative being finalized today is supported by our determination that the clear weight of the evidence is that the trading program achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources. The 2012 demonstration showed that CSAPR as finalized and amended in 2011 and 2012 meets the Regional Haze Rule’s criteria for a demonstration of greater reasonable progress than BART. This 2012 demonstration is the primary evidence that the Texas trading program achieves greater reasonable progress than BART. However, the states participating in CSAPR are now slightly different than the geographic scope of CSAPR assumed in the 2012 analytic demonstration. The changes to states participating in both CSAPR NOx trading programs resulting from EPA’s response to the D.C. Circuit’s remand were found by us to have no adverse impact on the 2012 determination that CSAPR participation remains better-than-BART.[130] Regarding SO_2 emissions from Texas, as detailed below, the BART alternative is projected to accomplish emission levels from Texas EGUs that are similar to the emission levels from Texas EGUs that would have been realized from the SO_2 trading program under CSAPR. The changes to the geographic scope of the NOx

[130] 81 FR 78954, 78962 (November 10, 2016) and final action signed September 21, 2017 available at *regulations.gov* in Docket No. EPA-HQ-OAR-2016-0598

CSAPR programs combined with the expectation that the Texas trading program will reduce the SO_2 emissions of EGUs in Texas to levels similar to CSAPR-participation levels, despite slight differences in EGU participation between the two SO_2 programs, lead to the finding here that post-remand CSAPR and the Texas BART alternative program are better-than-BART for Texas.

The differences in Texas EGU participation in CSAPR and this BART alternative are either not significant or, in some cases, work to demonstrate the relative stringency of the BART alternative as compared to CSAPR. If Texas EGUs were still required to participate in CSAPR's SO_2 trading program, it would be plainly consistent with previous findings and approvals that CSAPR is an acceptable BART alternative. The Texas trading program will result in emissions from the covered EGUs and other EGUs in Texas that are no higher than if Texas EGUs were still required to participate in CSAPR's SO_2 trading program, and thus the clear weight of evidence is that the Texas trading program will provide more reasonable progress than BART. Still regarding 40 CFR 51.308(e)(2)(i)(E), we have considered the question of whether in applying this portion of the Regional Haze Rule we should take as the baseline the application of source-specific BART at the covered sources. We interpret the rule to not require that approach in this situation, given that 51.308(e)(2)(i)C) provides for an exception (which we are exercising) to the requirement for source-specific BART determinations for the covered sources. We are not making any source-specific BART determinations in this action, nor did Texas do so in its 2009 SIP submission.

Table 8 below identifies the participating units and their unit-level allocations under the Texas SO_2 trading program. These allocations are the same as under CSAPR.

Table 8. Allocations for Texas EGUs Subject to the FIP SO_2 Trading Program

Owner/Operator	Units	Allocations (tpy)
AEP	Welsh Power Plant Unit 1	6,496
	Welsh Power Plant Unit 2	7,050
	Welsh Power Plant Unit 3	7,208
	H W Pirkey Power Plant Unit 1	8,882
	Wilkes Unit 1	14
	Wilkes Unit 2	2
	Wilkes Unit 3	3
CPS Energy	JT Deely Unit 1	6,170
	JT Deely Unit 2	6,082
	Sommers Unit 1	55
	Sommers Unit 2	7
Dynegy	Coleto Creek Unit 1	9,057
El Paso Electric	Newman Unit 2	1
	Newman Unit 3	1
	Newman Unit 4	2
LCRA	Fayette / Sam Seymour Unit 1	7,979
	Fayette / Sam Seymour Unit 2	8,019
Luminant	Big Brown Unit 1	8,473
	Big Brown Unit 2	8,559
	Martin Lake Unit 1	12,024
	Martin Lake Unit 2	11,580
	Martin Lake Unit 3	12,236
	Monticello Unit 1	8,598
	Monticello Unit 2	8,795
	Monticello Unit 3	12,216
	Sandow Unit 4	8,370
	Stryker ST2	145
	Graham Unit 2	226
NRG	Limestone Unit 1	12,081
	Limestone Unit 2	12,293
	WA Parish Unit WAP4	3
	WA Parish Unit WAP5	9,580
	WA Parish Unit WAP6	8,900
	WA Parish Unit WAP7	7,653
Xcel	Tolk Station Unit 171B	6,900
	Tolk Station Unit 172B	7,062
	Harrington Unit 061B	5,361
	Harrington Unit 062B	5,255
	Harrington Unit 063B	5,055
Total		238,393

The total annual allocation for all sources in the Texas SO_2 trading program is 238,393 tons. In addition, a Supplemental Allowance pool initially holds an additional 10,000 tons for a maximum total annual allocation of 248,393 tons. The Administrator may allocate a limited number of additional allowances from this pool to sources whose emissions exceed their annual allocation, pursuant to 40 CFR 97.912. Under CSAPR, the total allocations for all existing EGUs in Texas is 279,740 tons, with a total of 294,471 tons including the new unit set aside of 14,430 tons and the Indian country new unit set aside.[131] As shown in Table 9 below, the coverage of the Texas SO_2 trading program represents 81% of the total CSAPR allocation for Texas and 85% of the CSAPR allocations for existing units. The Supplemental Allowance pool contains an additional 10,000 tons, compared to the new unit set aside (NUSA) allowance allocation under CSAPR of 14,430 tons. Examining 2016 emissions, the EGUs covered by the program represent 89% of total Texas EGU emissions.

Table 9. Comparison of Texas SO_2 Trading Program Allocations to Previously Applicable CSAPR Allocations and to 2016 Emissions

	Annual Allocations in the Texas Trading Program (Tons per Year)	**% of Total Previously Applicable CSAPR Allocations (294,471 Tons per Year)**	**2016 Emissions (Tons per Year)**
Texas SO_2 Trading program sources	238,393	81%	218,291
Total EGU emissions			245,737

[131] An Indian Country new unit set-aside is established for each state under the CSAPR that provides allowances for future new units locating in Indian Country. The Indian Country new unit set-aside for Texas is 294 tons. See 40 CFR 97.710

Supplemental Allowance pool	10,000	3.4%	
Existing Sources not covered by trading program	No allocation	16%	27,446

The remaining 11% of the total 2016 emissions due to sources not covered by the program come from coal-fired units that on average are better controlled for SO_2 than the covered sources (26,795 tons in 2016) and gas units that rarely burn fuel oil (651 tons in 2016). The table below lists these coal-fired units. The average annual emission rate for 2016 is 0.50 lb/MMBTU for the coal-fired units participating in the trading program compared to 0.12 lb/MMBTU for the coal-fired units not covered by the program. Therefore, we conclude that in general, based on the current emission rates of the EGUs, should a portion of electricity generation shift to units not covered by the program, the net result would be a decrease in overall SO_2 emissions, as these non-participating units are on average much better controlled and emit far less SO_2 per unit of energy produced. Relative to current emission levels, should participating units increase their emissions rates and decrease generation to comply with their allocation, emissions from non-participating units may see a small increase.

Table 10. Coal-fired EGUs Not Covered by the Texas SO_2 Trading Program

	Previously Applicable CSAPR Allocation (tons)	**2016 Emissions (tons)**	**2016 Annual Average Emission Rate (lb/MMBtu)**
Fayette/Sam Seymour Unit 3	2,955	231	0.01
Gibbons Creek Unit 1	6,314	138	0.02
JK Spruce Unit 1	4,133	467	0.03

JK Spruce Unit 2	158	151	0.01
Oak Grove Unit 1	1,665	3,334	0.11
Oak Grove Unit 2*		3,727	0.12
Oklaunion Unit 1	4,386	1,530	0.11
San Miguel Unit 1	6,271	6,815	0.44
Sandow Station Unit 5A	773	1,117	0.11
Sandow Station Unit 5B	725	1,146	0.10
Sandy Creek Unit 1*		1,842	0.09
Twin Oaks Unit 1	2,326	1,712	0.21
Twin Oaks Unit 2	2,270	1,475	0.23
WA Parish Unit WAP8	4,071	3,112	0.16
Total	36,047	26,795	

* Oak Grove Unit 2 and Sandy Creek Unit 1 received allocations from the new unit set aside under the CSAPR program.

The exclusion of a large number of gas-fired units that occasionally burn fuel oil further limits allowances in the program as compared to CSAPR because CSAPR allocated these units allowances that are higher than their recent and current emissions. In 2016, these units emitted 651 tons of SO_2, but received allowances for over 5,000 tons. By excluding these sources from the program, those unused allowances are not available for purchase by other EGUs. We note the trading program does allow non-participating sources that previously had CSAPR allocations to opt-in to the trading program and receive an allocation equivalent to the CSAPR level allocation. Should some sources choose to opt-in to the program, the total number of allowances will increase by that amount. This will serve to increase the percentage of CSAPR allowances represented by the Texas SO_2 trading program and increase the portion of emissions covered by the program, more closely resembling the CSAPR program.

Finally, the Texas SO_2 trading program does not allow EGUs to purchase allowances from sources in other states. Under CSAPR, Texas EGUs were allowed to purchase allowances from other Group 2 states, a fact which could, and was projected to, result in an increase in annual allowances used in the State above the state budget. CSAPR also included a variability limit that was set at 18% of the State budget and an assurance level equal to the State's budget plus variability limit. The assurance level for Texas was set at 347,476 tons. The CSAPR assurance provisions are triggered if the State's emissions for a year exceed the assurance level. These assurance provisions require some sources to surrender two additional allowances per ton beyond the amount equal to their actual emissions, depending on their emissions and annual allocation level. In effect, under CSAPR, EGUs in Texas could emit above the allocation if willing to pay the market price of allowances and the cost associated with each incremental ton of emissions could triple if in the aggregate they exceeded the assurance level. The Texas trading program will have 248,393 tons of allowances allocated every year, with no ability to purchase additional allowances from sources outside of the State, preventing an increase beyond that annual allocation.[132] This includes an annual allocation of 10,000 allowances to the Supplemental Allowance pool. The Supplemental Allowance pool may grow over time as unused supplemental allowances remain available and allocations from retired units are placed in the supplemental pool but the total number of allowances that can be allocated in a control period from in this supplemental pool is limited to a maximum 54,711 tons plus the amount of any allowances placed in the pool that year from retired units and corrections. The 54,711-ton value is equal to 10,000 tons annually allocated to the pool plus 18% of the total annual allocation for participating units, mirroring the variability limit from CSAPR. The total number of allowances

[132] We note the trading program does allow non-participating sources that previously had CSAPR allocations to opt-in to the trading program and receive an allocation equivalent to the CSAPR level allocation. Should some sources choose to opt-in to the program, the total number of allowances will increase by that amount.

that can be allocated in a single year is therefore 293,104, which is the sum of the 238,393 budget for existing units plus 54,711. Annual average emissions for the covered sources will be less than or equal to 248,393 tons with some year to year variability constrained by the number of banked allowances and allowances available to be allocated during a control period from the Supplemental Allowance pool. If additional units opt into the program, additional allowances will be available corresponding to the amounts that those units would have been allocated under CSAPR. The projected SO_2 emissions from the affected Texas EGUs in the CSAPR + BART-elsewhere scenario were 266,600 tons per year. In a 2012 sensitivity analysis memo, EPA conducted a sensitivity analysis that confirmed that CSAPR would remain better-than-BART if Texas EGU emissions increased to approximately 317,100 tons.[133] Under the Texas SO_2 trading program, annual average EGU emissions are anticipated to remain well below 317,100 tons per year as annual allocations for participating units are held at 248,393 tons per year. Sources not covered by the program emitted less than 27,500 tons of SO_2 in 2016 and are not projected to significantly increase from this level. Any new units would be required to be well controlled and similar to the existing units not covered by the program, they would not significantly increase total emissions of SO_2. Furthermore, as discussed above, any load shifting to these new non-participating units would be projected to result in a net decrease in emissions per unit of electricity generated and at most a small increase in total SO_2 emissions compared to them not

[133] For the projected annual SO_2 emissions from Texas EGUs *see* Technical Support Document for Demonstration of the Transport Rule as a BART Alternative, Docket ID No. EPA–HQ–OAR–2011– 0729–0014 (December 2011) (2011 CSAPR/BART Technical Support Document), available in the docket for this action, at table 2–4. Certain CSAPR budgets were increased after promulgation of the CSAPR final rule (and the increases were addressed in the 2012 CSAPR/BART sensitivity analysis memo), *See* memo titled ''Sensitivity Analysis Accounting for Increases in Texas and Georgia Transport Rule State Emissions Budgets,'' Docket ID No. EPA–HQ–OAR–2011–0729–0323 (May 29, 2012), available in the docket for this action. The increase in the Texas SO_2 budget was 50,517 tons which, when added to the Texas SO_2 emissions projected in the CSAPR + BART-elsewhere scenario of 266,600 tons, yields total potential SO_2 emissions from Texas EGUs of approximately 317,100 tons.

having been brought into operation. We note that total emissions of SO_2 from all EGU sources in Texas in 2016 were 245,737 tons.

We also note that state-wide EGU emissions in Texas have decreased considerably since the 2002 baseline period, reflecting market changes and reductions due to requirements such as CAIR/CSAPR. In 2002, Texas EGU emissions were 560,860 tons of SO_2 compared to emissions of 245,737 tons in 2016, a reduction of over 56%. The Texas SO_2 trading program locks in the large majority of these reductions by limiting allocation of allowances to 248,393 tons per year for participating sources. While the Texas program does not include all EGU sources in the State, as discussed above, the EGUs outside of the program contribute relatively little to the total state emissions and these units on average are better controlled for SO_2 than the units subject to the Texas program.

C. Specific Texas SO_2 Trading Program Features

The Texas SO_2 Trading Program is an intrastate cap-and-trade program for listed covered sources in the State of Texas. The EPA is promulgating the Texas SO_2 Trading Program under 40 CFR 52.2312 and subpart FFFFF of part 97. The State of Texas may choose to remain under the Texas SO_2 Trading Program or replace it with an appropriate SIP. If the State of Texas is interested in pursuing delegation of the Texas SO_2 Trading Program, the request would need to provide a demonstration of the State's statutory authority to implement any delegated elements.

The Texas SO_2 Trading Program is modeled after the EPA's CSAPR SO_2 Group 2 Trading Program and satisfies the requirements of 51.308(e)(2)(vi). Similar to the CSAPR SO_2 Group 2 Trading Program, the Texas SO_2 Trading Program sets an SO_2 emission budget for the State of Texas. Authorizations to emit SO_2, known as allowances, are allocated to affected units.

The Texas SO_2 Trading Program provides flexibility to affected units and sources by allowing units and sources to determine their own compliance path; this includes adding or operating control technologies, upgrading or improving controls, switching fuels, and using allowances. Sources can buy and sell allowances and bank (save) allowances for future use as long as each source holds enough allowances to account for its emissions of SO_2 by the end of the compliance period.

Pursuant to the requirements of 51.308(e)(2)(vi)(A), the applicability of the Texas SO_2 Trading Program is defined in 40 CFR 97.904. Section 97.904(a) identifies the subject units, which include all BART-eligible coal-fired EGUs, additional coal-fired EGUs, and several BART-eligible gas-fired and gas/fuel oil-fired EGUs, all of which were previously covered by the CSAPR SO_2 Group 2 Trading Program. Additionally, under 40 CFR 97.904(b), the EPA is providing an opportunity for any other unit in the State of Texas that was subject to the CSAPR SO_2 Group 2 Trading Program to opt-in to the Texas SO_2 Trading Program. We discuss in Section V.B above, how the applicability results in coverage of the Texas SO_2 trading program representing 81% of the total CSAPR allocation for Texas and 85% of the CSAPR allocations for existing units, and how potential shifts in generation would result in an insignificant change in emissions. The Texas SO_2 Trading Program establishes the statewide SO_2 budget for the subject units at 40 CFR 97.910(a). This budget is equal to the allowances for each subject unit identified under 97.904(a) and 97.911(a). As units opt-in to the Texas SO_2 Trading under 97.904(b), the allowances for each of these units will equal their CSAPR SO_2 Group 2 allowances under 97.911(b). Additionally, the EPA has established a Supplemental Allowance Pool with a budget of 10,000 tons of SO_2 to provide compliance assistance to subject units and sources. Section 40 CFR 97.912 establishes how allowances are allocated from the Supplemental

Allowance Pool to sources (collections of participating units at a facility) that have reported total emissions for that control period exceeding the total amounts of allowances allocated to the participating units at the source for that control period (before any allocation from the Supplemental Allowance Pool). For any control period, the maximum supplemental allocation from the Supplemental Allowance Pool that a source may receive is the amount by which the total emissions reported for its participating units exceed the total allocations to its participating units (before any allocation from the Supplemental Allowance Pool). If the total amount of allowances available for allocation from the Supplemental Allowance Pool for a control period is less than the sum of these maximum allocations, sources will receive less than the maximum supplemental allocation from the Supplemental Allowance Pool, where the amount of supplemental allocations for each source is determined in proportion to the sources' respective maximum allocations, with one exception. While all other sources required to participate in the trading program have flexibility to transfer allowances among multiple participating units under the same owner/operator when planning operations, Coleto Creek consists of only one coal-fired unit and is the only coal-fired unit in Texas owned and operated by Dynegy. To provide this source additional flexibility, Coleto Creek will be allocated its maximum supplemental allocation from the Supplemental Allowance Pool as long as there are sufficient allowances in the Supplemental Allowance Pool available for allocation, and its actual allocation will not be reduced in proportion with any reductions made to the supplemental allocations to other sources. Section 97.921 establishes how the Administrator will record the allowances for the Texas SO_2 Trading Program and ensures that the Administrator will not record more allowances than are available under the program consistent with 40 CFR 51.308(e)(2)(vi)(B). The monitoring, recordkeeping, and reporting provisions for the Texas SO_2 Trading Program at 40 CFR 97.930 –

97.935 are consistent with those requirements in the CSAPR SO_2 Group 2 Trading Program. The provisions in 40 CFR 97.930 – 97.935 require the subject units to comply with the monitoring, recordkeeping, and reporting requirements for SO_2 emissions in 40 CFR part 75; thereby satisfying the requirements of 51.308(e)(2)(vi)(C) – (E). The Texas SO_2 Trading Program will be implemented by the EPA using the Allowance Management System. The use of the Allowance Management System will provide a consistent approach to implementation and tracking of allowances and emissions for the EPA, subject sources, and the public consistent with the requirements of 40 CFR 51.308(e)(2)(vi)(F). Additionally, the EPA is promulgating requirements at 40 CFR 97.913 – 97.918 for designated and alternate designated representatives that satisfy the requirements of 40 CFR 51.308(e)(2)(vi)(G) and are consistent with the EPA's other trading programs under 40 CFR Part 97. Allowance transfer provisions for the Texas SO_2 Trading Program at 40 CFR 97.922 and 97.923 provide procedures that allow timely transfer and recording of allowances; these provisions will minimize administrative barriers to the operation of the allowance market and ensure that such procedures apply uniformly to all sources and other potential participants in the allowance market, consistent with 40 CFR 51.308(e)(2)(vi)(H). Compliance provisions for the Texas SO_2 Trading Program at 40 CFR 97.924 prohibit a source from emitting a total tonnage of SO_2 that exceeds the tonnage value of its SO_2 allowance holdings as required by 40 CFR 51.308(e)(2)(vi)(I). The Texas SO_2 Trading Program includes automatic allowance surrender provisions at 40 CFR 97.924(d) that apply consistently from source to source and the tonnage value of the allowances deducted shall equal at least three times the tonnage of the excess emissions, consistent with the penalty provisions at 40 CFR 51.308(e)(2)(vi)(J). The Texas SO_2 Trading Program provides for banking of allowances under 40 CFR 97.926; Texas SO_2 Trading Program allowances are valid for compliance in the control period of issuance or may be banked for future use, consistent with 40 CFR 51.308(e)(2)(vi)(K). The EPA is promulgating the Texas SO_2 Trading Program as a BART-alternative for Texas' Regional Haze obligations. The CAA and EPA's implementing regulations require periodic review of the state's regional haze approach under 40 CFR 51.308(g) to evaluate progress towards the reasonable progress goals for Class I areas located within the State and Class I areas located outside the State affected by emissions from within the State. Because the Texas SO_2 Trading Program is a BART-alternative for Texas' Regional Haze obligations, this program is required to be reviewed in each progress report. We anticipate this progress report will provide the information needed to assess program performance, as required by 40 CFR 51.308(e)(2)(vi)(L).

As previously discussed, the EPA modeled the Texas SO_2 Trading Program after the EPA's CSAPR SO_2 Group 2 Trading Program. Relying on a trading program structure that is already in effect enables the EPA, the subject sources, and the public to benefit from the use of the Allowance Management System, forms, and monitoring, recordkeeping, and reporting requirements. However, there are a few features of the Texas SO_2 Trading Program that are separate and unique from the EPA's CSAPR. First, the program does not address new units that are built after the inception of the program; these units would be permitted and constructed using emission control technology determined under either BACT or LAER review, as applicable. Second, the Texas SO_2 Trading Program provides that sources that were previously covered under the CSAPR SO_2 Group 2 Trading Program, but are not subject to the requirements of subpart FFFFF of part 97 can opt-in to the Texas SO_2 Trading Program at the allocation level established under CSAPR. Finally, the Texas SO_2 Trading Program includes a Supplemental Allowance Pool to provide some compliance assistance to units whose emissions exceed their allocations. The amount of allocations to the Supplemental Allowance Pool each year is less than the portion of the Texas budget under the CSAPR SO_2 Group 2 Trading Program that would have been set aside each year for new units (and which would have been allocated to existing units to the extent not needed by new units).

VI. Final Action

A. Regional Haze

We are finalizing our identification of BART-eligible EGUs. We are approving the portion of the Texas Regional Haze SIP that addresses the BART requirement for EGUs for PM. As discussed elsewhere in this notice, we are replacing Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. To address the SO_2 BART requirements for EGUs, we are promulgating a FIP to replace Texas' reliance on CAIR with reliance on an intrastate SO_2 trading program for certain EGUs identified in Table 11 below. This FIP is codified under 40 CFR 52.2312 and subpart FFFFF of part 97. We are finalizing our determination that BART-eligible EGUs not covered by the intrastate SO_2 trading program are not subject-to-BART. This final action is also part of the long-term strategy to address the reasonable progress requirements for Texas EGUs, which remain outstanding after the remand of our reasonable progress FIP by the Fifth Circuit Court of Appeals. However, further assessment and analysis of the CAA's reasonable progress factors will be needed before the Regional Haze Rule's reasonable progress requirements will be fully addressed for Texas.

Table 11. Texas EGUs Subject to the FIP SO_2 Trading Program

Owner/Operator	Units
AEP	Welsh Power Plant Units 1, 2, and 3
	H W Pirkey Power Plant Unit 1
	Wilkes Units 1*, 2*, and 3*
CPS Energy	JT Deely Units 1 and 2, Sommers Units 1* and 2*
Dynegy	Coleto Creek Unit 1
LCRA	Fayette / Sam Seymour Units 1 and 2
Luminant	Big Brown Units 1 and 2
	Martin Lake Units 1, 2, and 3
	Monticello Units 1, 2, and 3
	Sandow Unit 4
	Stryker ST2*
	Graham Unit 2*
NRG	Limestone Units 1 and 2
	WA Parish Units WAP4*, WAP5, WAP6, WAP7
Xcel	Tolk Station Units 171B and 172B
	Harrington Units 061B, 062B, and 063B
El Paso Electric	Newman Units 2*, 3*, and 4*

* Gas-fired or gas/fuel oil-fired units

B. Interstate Visibility Transport

In our January 5, 2016 final action[134] we disapproved the portion of Texas' SIP revisions intended to address interstate visibility transport for six NAAQS, including the 1997 8-hour ozone and 1997 $PM_{2.5}$.[135] That rulemaking was challenged, however, and in December 2016, following the submittal of a request by the EPA for a voluntary remand of the parts of the rule under challenge, the Fifth Circuit Court of Appeals remanded the rule in its entirety without vacatur.[136] In our January 4, 2017 proposed action we proposed to reconsider the basis of our

[134] 81 FR 296 (Jan. 5, 2016).
[135] Specifically, we previously disapproved the relevant portion of these Texas' SIP submittals: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). 79 FR 74818, 74821; 81 FR 296, 302.
[136] *Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016).

prior disapproval of Texas' SIP revisions addressing interstate visibility transport under CAA section 110(a)(2)(D)(i)(II) for six NAAQS. We have reconsidered the basis of our prior disapproval and are disapproving Texas' SIP revisions addressing interstate visibility transport under CAA section 110(a)(2)(D)(i)(II) for six NAAQS. We are finalizing a FIP to fully address Texas' interstate visibility transport obligations for the following six NAAQS: (1) 1997 8-hour ozone, (2) 1997 $PM_{2.5}$ (annual and 24 hour), (3) 2006 $PM_{2.5}$ (24-hour), (4) 2008 8-hour ozone, (5) 2010 1-hour NO_2 and (6) 2010 1-hour SO_2. The BART FIP emission reductions are consistent with the level of emission reductions relied upon by other states during Regional Haze consultation, and it is therefore adequate to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states in accordance with CAA section 110(a)(2)(D)(i)(II).

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Overview, Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a "significant regulatory action" under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011).

B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs

This action is not an Executive Order 13771 regulatory action because this action is not significant under Executive Order 12866.

C. Paperwork Reduction Act

The Office of Management and Budget (OMB) has determined that this action imposes a collection burden that is subject to the Paperwork Reduction Act (PRA). An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Therefore, the EPA will obtain a valid OMB control number unless OMB determines that these collection activities are covered under an existing information collection request (ICR) and associated OMB control number. If the EPA obtains a new OMB control number or amends an existing ICR with a valid OMB control number, the EPA will provide notice in the Federal Register as required by the PRA and the implementing regulations, with burden estimates, and, if necessary, publish a technical amendment to 40 CFR part 9 to display the new OMB control number for the information collection activities contained in this final rule.

D. Regulatory Flexibility Act

I certify that this action will not have a significant impact on a substantial number of small entities. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. This rule does not impose any requirements or create impacts on small entities. This FIP action under Section 110 of the CAA will not create any new requirement with which small entities must comply. Accordingly, it affords no opportunity for the EPA to fashion for small entities less burdensome compliance or reporting requirements or timetables or exemptions from all or part of the rule. The fact that the CAA prescribes that various consequences (e.g., emission limitations) may or will flow from this action does not mean that the EPA either can or must conduct a regulatory flexibility analysis for this action. We have therefore concluded that, this action will have no net regulatory burden for all directly regulated small entities.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule.

H. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

Executive Order 13045: Protection of Children From Environmental Health Risks and

Safety Risks[137] applies to any rule that: (1) Is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under Section 5-501 of the EO has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this rule will limit emissions of SO_2, the rule will have a beneficial effect on children's health by reducing air pollution.

I. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

J. National Technology Transfer and Advancement Act (NTTAA)

This action involves technical standards. The EPA has decided to use the applicable monitoring requirements of 40 CFR part 75. Part 75 already incorporates a number of voluntary consensus standards. Consistent with the Agency's Performance Based Measurement System (PBMS), part 75 sets forth performance criteria that allow the use of alternative methods to the

[137] 62 FR 19885 (Apr. 23, 1997).

ones set forth in part 75. The PBMS approach is intended to be more flexible and cost-effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. At this time, EPA is not recommending any revisions to part 75; however, EPA periodically revises the test procedures set forth in part 75. When EPA revises the test procedures set forth in part 75 in the future, EPA will address the use of any new voluntary consensus standards that are equivalent. Currently, even if a test procedure is not set forth in part 75, EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified; however, any alternative methods must be approved through the petition process under 40 CFR 75.66 before they are used.

K. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does **not** have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). We have determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. The rule limits emissions of SO_2 from certain facilities in Texas.

L. Congressional Review Act (CRA)

This rule is exempt from the CRA because it is a rule of particular applicability.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxides, Visibility, Interstate transport of pollution, Regional haze, Best available retrofit technology.

List of Subjects in 40 CFR Part 97

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Reporting and recordkeeping requirements, Sulfur dioxides.

Dated: September 29, 2017.

E. Scott Pruitt,

Administrator

40 CFR part 52 is amended as follows:

PART 52–APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq*.

Subpart SS - Texas

2. In § 52.2270, paragraph (e) is amended by adding a new entry for "Texas Regional Haze BART Requirement for EGUs for PM" at the end of the second table in paragraph (e) entitled "EPA Approved Nonregulatory Provisions and Quasi-Regulatory Measures in the Texas SIP."

3. Section 52.2304 is amended by adding new paragraph (f).

4. Subpart SS is amended by adding new Section 52.2312.

The revisions read as follows:

§ 52.2270 Identification of plan.

* * * * *

(e) * * *

EPA APPROVED NONREGULATORY PROVISIONS AND QUASI-REGULATORY MEASURES IN THE TEXAS SIP

Name SIP provision	Applicable geographic or nonattainment area	State submittal date/ effective date	EPA approval date	Explanation
* * * * *				

Texas Regional Haze BART Requirement for EGUs for PM	Statewide	3/31/2009	**[Insert date of publication in the Federal Register] [Insert Federal Register citation]**	

* * * * *

§ 52.2304 Visibility protection.

* * * * *

(f) Measures Addressing Disapproval Associated with NO_X and SO_2.

(1) The deficiencies associated with NO_X identified in EPA's limited disapproval of the regional haze plan submitted by Texas on March 31, 2009, and EPA's disapprovals in 52.2304(d), are satisfied by § 52.2283(d).

(2) The deficiencies associated with SO_2 identified in EPA's limited disapproval of the regional haze plan submitted by Texas on March 31, 2009, and EPA's disapprovals in 52.2304(d), are satisfied by § 52.2312.

* * * * *

§ 52.2312 – Requirements for the control of SO_2 emissions to address in full or in part requirements related to BART, Reasonable Progress, and Interstate Visibility Transport.

1. The Texas SO_2 Trading Program provisions set forth in subpart FFFFF of part 97 of this chapter constitute the Federal Implementation Plan provisions fully addressing Texas' obligations with respect to best available retrofit technology under section 169A of the Act and the deficiencies associated with EPA's disapprovals in 52.2304(d) and partially addressing Texas' obligations with respect to reasonable progress under section 169A of the Act, as those obligations relate to emissions of sulfur dioxide (SO_2) from electric generating units (EGUs).
2. The provisions of subpart FFFFF of part 97 of this chapter apply to sources in Texas but not sources in Indian country located within the borders of Texas, with regard to emissions in 2019 and each subsequent year.

PART 97 – FEDERAL NO_X BUDGET TRADING PROGRAM, CAIR NO_X AND SO_2 TRADING PROGRAMS, CSAPR NO_X AND SO_2 TRADING PROGRAMS, AND TEXAS SO_2 TRADING PROGRAM

40 CFR part 97 is amended as follows:

3. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7601, and 7651, *et seq*.

4. Part 97 is amended by adding subpart FFFFF and paragraphs 97.901 through 97.935 to read as follows:

Subpart FFFFF - Texas SO_2 Trading Program

97.901 Purpose.

97.902 Definitions.

97.903 Measurements, abbreviations, and acronyms.

97.904 Applicability.

97.905 Retired unit exemptions.

97.906 General provisions.

97.907 Computation of time.

97.908 Administrative appeal procedures.

97.909 [RESERVED]

97.910 Texas SO_2 Trading Program and Supplemental Allowance Pool Budgets.

97.911 Texas SO_2 Trading Program allowance allocations.

97.912 Texas SO_2 Trading Program Supplemental Allowance Pool.

97.913 Authorization of designated representative and alternate designated representative.

97.914 Responsibilities of designated representative and alternate designated representative.

97.915 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

97.916 Certificate of representation.

97.917 Objections concerning designated representative and alternate designated representative.

97.918 Delegation by designated representative and alternate designated representative.

97.919 [RESERVED]

97.920 Establishment of compliance accounts and general accounts.

97.921 Recordation of Texas SO_2 Trading Program allowance allocations.

97.922 Submission of Texas SO_2 Trading Program allowance transfers.

97.923 Recordation of Texas SO_2 Trading Program allowance transfers.

97.924 Compliance with Texas SO_2 Trading Program emissions limitations.

97.925 [RESERVED]

97.926 Banking.

97.927 Account error.

97.928 Administrator's action on submissions.

97.929 [RESERVED]

97.930 General monitoring, recordkeeping, and reporting requirements.

97.931 Initial monitoring system certification and recertification procedures.

97.932 Monitoring system out-of-control periods.

97.933 Notifications concerning monitoring.

97.934 Recordkeeping and reporting.

97.935 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

§ 97.901 Purpose.

This subpart sets forth the general, designated representative, allowance, and monitoring provisions for the Texas SO_2 Trading Program under sections 110 and 169A of the Clean Air Act and 40 CFR 52.2312, as a means of addressing Texas' obligations with respect to BART, reasonable progress, and interstate visibility transport as those obligations relate to sulfur dioxide emissions from electricity generating units.

§ 97.902 Definitions.

The terms used in this subpart shall have the meanings set forth in this section as follows:

Acid Rain Program means a multi-state SO_2 and NO_X air pollution control and emission reduction program established by the Administrator under title IV of the Clean Air Act and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Director of the Clean Air Markets Division (or its successor determined by the Administrator) of the United States Environmental Protection Agency, the Administrator's duly authorized representative under this subpart.

Allocate or *allocation* means, with regard to Texas SO_2 Trading Program allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart or any SIP revision submitted by the State approved by the Administrator, of the amount of such Texas SO_2 Trading Program allowances to be initially credited, at no cost to the recipient, to a Texas SO_2 Trading Program unit.

Allowance Management System means the system by which the Administrator records allocations, transfers, and deductions of Texas SO_2 Trading Program allowances under the Texas SO_2 Trading Program. Such allowances are allocated, recorded, held, transferred, or deducted only as whole allowances.

Allowance Management System account means an account in the Allowance Management System established by the Administrator for purposes of recording the allocation, holding, transfer, or deduction of Texas SO_2 Trading Program allowances.

Allowance transfer deadline means, for a control period in a given year, midnight of March 1 (if it is a business day), or midnight of the first business day thereafter (if March 1 is not a business day), immediately after such control period and is the deadline by which a Texas SO_2

Trading Program allowance transfer must be submitted for recordation in a Texas SO_2 Trading Program source's compliance account in order to be available for use in complying with the source's Texas SO_2 Trading Program emissions limitation for such control period in accordance with §§97.906 and 97.924.

Alternate designated representative means, for a Texas SO_2 Trading Program source and each Texas SO_2 Trading Program unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to act on behalf of the designated representative in matters pertaining to the Texas SO_2 Trading Program. If the Texas SO_2 Trading Program source is also subject to the Acid Rain Program or CSAPR NO_X Ozone Season Group 2 Trading Program, then this natural person shall be the same natural person as the alternate designated representative as defined in the respective program.

Authorized account representative means, for a general account, the natural person who is authorized, in accordance with this subpart, to transfer and otherwise dispose of Texas SO_2 trading Program allowances held in the general account and, for a Texas SO_2 Trading Program source's compliance account, the designated representative of the source.

Automated data acquisition and handling system or *DAHS* means the component of the continuous emission monitoring system, or other emissions monitoring system approved for use under this subpart, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by this subpart.

Business day means a day that does not fall on a weekend or a federal holiday.

Clean Air Act means the Clean Air Act, 42 U.S.C. 7401, *et seq*.

Coal means “coal” as defined in §72.2 of this chapter.

Commence commercial operation means, with regard to a Texas SO_2 Trading Program unit, to have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means an Allowance Management System account, established by the Administrator for a Texas SO_2 Trading Program source under this subpart, in which any Texas SO_2 Trading Program allowance allocations to the Texas SO_2 Trading Program units at the source are recorded and in which are held any Texas SO_2 Trading Program allowances available for use for a control period in a given year in complying with the source's Texas SO_2 Trading Program emissions limitation in accordance with §§97.906 and 97.924.

Continuous emission monitoring system or *CEMS* means the equipment required under this subpart to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes and using an automated data acquisition and handling system (DAHS), a permanent record of SO_2 emissions, stack gas volumetric flow rate, stack gas moisture content, and O_2 or CO_2 concentration (as applicable), in a manner consistent with part 75 of this chapter and §§97.930 through 97.935. The following systems are the principal types of continuous emission monitoring systems:

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A SO_2 monitoring system, consisting of a SO_2 pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of SO_2 emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A CO_2 monitoring system, consisting of a CO_2 pollutant concentration monitor (or an O_2 monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An O_2 monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period starting January 1 of a calendar year, except as provided in §97.906(c)(3), and ending on December 31 of the same year, inclusive.

CSAPR NO_X Ozone Season Group 2 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart EEEEE of this part and §52.38(b)(1), (b)(2)(i) and (iii), (b)(6) through (11), and (b)(13) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under §52.38(b)(7) or (8) of this chapter or that is established in a SIP revision approved by the Administrator under §52.38(b)(6) or (9) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

Designated representative means, for a Texas SO_2 Trading Program source and each Texas SO_2 Trading Program unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with this subpart, to represent and legally bind each owner and operator in matters pertaining to the Texas SO_2 Trading Program. If the Texas SO_2 Trading Program source is also subject to the Acid Rain Program or CSAPR NO_X Ozone Season Group 2 Trading Program, then this natural person shall be the same natural person as the designated representative as defined in the respective program.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the designated representative, and as modified by the Administrator:

(1) In accordance with this subpart; and

(2) With regard to a period before the unit or source is required to measure, record, and report such air pollutants in accordance with this subpart, in accordance with part 75 of this chapter.

Excess emissions means any ton of emissions from the Texas SO_2 Trading Program units at a Texas SO_2 Trading Program source during a control period in a given year that exceeds the Texas SO_2 Trading Program emissions limitation for the source for such control period.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in 2005 or any calendar year thereafter.

General account means an Allowance Management System account, established under this subpart, which is not a compliance account.

Generator means a device that produces electricity.

Heat input means, for a unit for a specified period of unit operating time, the product (in mmBtu) of the gross calorific value of the fuel (in mmBtu/lb) fed into the unit multiplied by the fuel feed rate (in lb of fuel/time) and unit operating time, as measured, recorded, and reported to the Administrator by the designated representative and as modified by the Administrator in accordance with this subpart and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust.

Heat input rate means, for a unit, the quotient (in mmBtu/hr) of the amount of heat input for a specified period of unit operating time (in mmBtu) divided by unit operating time (in hr) or, for a unit and a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Indian country means “Indian country” as defined in 18 U.S.C. 1151.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Monitoring system means any monitoring system that meets the requirements of this subpart, including a continuous emission monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe, rounded to the nearest tenth) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount (in MWe, rounded to the nearest tenth) as of such completion as specified by the person conducting the physical change.

Natural gas means “natural gas” as defined in §72.2 of this chapter.

Natural person means a human being, as opposed to a legal person, which may be a private (i.e., business entity or non-governmental organization) or public (i.e., government) organization.

Operate or *operation* means, with regard to a unit, to combust fuel.

Operator means, for a Texas SO_2 Trading Program source or a Texas SO_2 Trading Program unit at a source respectively, any person who operates, controls, or supervises a Texas SO_2 Trading Program unit at the source or the Texas SO_2 Trading Program unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such source or unit.

Owner means, for a Texas SO_2 Trading Program source or a Texas SO_2 Trading Program unit at a source, any of the following persons:

(1) Any holder of any portion of the legal or equitable title in a Texas SO_2 Trading Program unit at the source or the Texas SO_2 Trading Program unit;

(2) Any holder of a leasehold interest in a Texas SO_2 Trading Program unit at the source or the Texas SO_2 Trading Program unit, provided that, unless expressly provided for in a leasehold agreement, "owner" shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such Texas SO_2 Trading Program unit; and

(3) Any purchaser of power from a Texas SO_2 Trading Program unit at the source or the Texas SO_2 Trading Program unit under a life-of-the-unit, firm power contractual arrangement.

Permanently retired means, with regard to a unit, a unit that is unavailable for service and that the unit's owners and operators do not expect to return to service in the future.

Permitting authority means "permitting authority" as defined in §§70.2 and 71.2 of this chapter.

Receive or *receipt of* means, when referring to the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official log, or by a notation made on the document, information, or correspondence, by the Administrator in the regular course of business.

Recordation, *record,* or *recorded* means, with regard to Texas SO_2 Trading Program allowances, the moving of Texas SO_2 Trading Program allowances by the Administrator into, out of, or between Allowance Management System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

Replacement, replace, or *replaced* means, with regard to a unit, the demolishing of a unit, or the permanent retirement and permanent disabling of a unit, and the construction of another unit (the replacement unit) to be used instead of the demolished or retired unit (the replaced unit).

Serial number means, for a Texas SO_2 Trading Program allowance, the unique identification number assigned to each Texas SO_2 Trading Program allowance by the Administrator.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. This definition does not change or otherwise affect the definition of “major source”, “stationary source”, or “source” as set forth and implemented in a title V operating permit program or any other program under the Clean Air Act.

State means Texas.

Submit or *serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery;

(4) Provided that compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

Texas SO_2 Trading Program means an SO_2 air pollution control and emission reduction program established in accordance with this subpart and 40 CFR 52.2312 (including such a program that is revised in a SIP revision approved by the Administrator), or established in a SIP revision approved by the Administrator, as a means of addressing the State's obligations with respect to BART, reasonable progress, and interstate visibility transport as those obligations relate to emissions of SO_2 from electricity generating units.

Texas SO_2 Trading Program allowance means a limited authorization issued and allocated by the Administrator under this subpart, or by a State or permitting authority under a SIP revision approved by the Administrator, to emit one ton of SO_2 during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the Texas SO_2 Trading Program.

Texas SO_2 Trading Program allowance deduction or *deduct Texas SO_2 Trading Program allowances* means the permanent withdrawal of Texas SO_2 Trading Program allowances by the Administrator from a compliance account (*e.g.*, in order to account for compliance with the Texas SO_2 Trading Program emissions limitation).

Texas SO_2 Trading Program allowances held or *hold Texas SO_2 Trading Program allowances* means the Texas SO_2 Trading Program allowances treated as included in an Allowance Management System account as of a specified point in time because at that time they:

(1) Have been recorded by the Administrator in the account or transferred into the account by a correctly submitted, but not yet recorded, Texas SO_2 Trading Program allowance transfer in accordance with this subpart; and

(2) Have not been transferred out of the account by a correctly submitted, but not yet recorded, Texas SO_2 Trading Program allowance transfer in accordance with this subpart.

Texas SO_2 Trading Program emissions limitation means, for a Texas SO_2 Trading Program source, the tonnage of SO_2 emissions authorized in a control period by the Texas SO_2 Trading Program allowances available for deduction for the source under § 97.924(a) for such control period.

Texas SO_2 Trading Program source means a source that includes one or more Texas SO_2 Trading Program units.

Texas SO_2 Trading Program unit means a unit that is subject to the Texas SO_2 Trading Program under §97.904.

Unit means a stationary, fossil-fuel-fired boiler, stationary, fossil-fuel-fired combustion turbine, or other stationary, fossil-fuel-fired combustion device. A unit that undergoes a physical change or is moved to a different location or source shall continue to be treated as the same unit. A unit (the replaced unit) that is replaced by another unit (the replacement unit) at the same or a different source shall continue to be treated as the same unit, and the replacement unit shall be treated as a separate unit.

Unit operating day means, with regard to a unit, a calendar day in which the unit combusts any fuel.

Unit operating hour or hour of unit operation means, with regard to a unit, an hour in which the unit combusts any fuel.

§ 97.903 Measurements, abbreviations, and acronyms.

Measurements, abbreviations, and acronyms used in this subpart are defined as follows:

BART – best available retrofit technology

Btu—British thermal unit

CO_2—carbon dioxide

CSAPR—Cross-State Air Pollution Rule

H_2O—water

hr—hour

lb—pound

mmBtu—million Btu

MWe—megawatt electrical

NO_X—nitrogen oxides

O_2—oxygen

ppm—parts per million

scfh—standard cubic feet per hour

SIP—State implementation plan

SO_2—sulfur dioxide

§ 97.904 Applicability.

(a) Each of the units in Texas listed in the table in §97.911(a)(1) shall be a Texas SO_2 Trading Program unit, and each source that includes one or more such units shall be a Texas SO_2 Trading Program source, subject to the requirements of this subpart.

(b) *Opt-in provisions*. (1) The provisions of paragraph (b) of this section apply to each unit in Texas that:

(i) Is listed in the table entitled "Unit Level Allocations under the CSAPR FIPs after Tolling," EPA-HQ-OAR-2009-0491-5028, available at *www.regulations.gov*;

(ii) Is not a Texas SO_2 Trading Program unit under paragraph (a) of this section; and

(iii) Has not received a determination of non-applicability under 40 CFR 97.404(c), 97.504(c), 97.704(c), or 97.804(c).

(2) The designated representative of a unit described in paragraph (b)(1) of this section may submit an opt-in application seeking authorization for the unit to participate in the Texas SO_2 Trading Program, provided that the unit has operated in the calendar year preceding submission of the opt-in application. Opt-in applications must be submitted in a format specified by the Administrator no later than October 1 of the year preceding the first control period for which authorization to participate in the Texas SO_2 Trading Program is sought.

(3) The Administrator shall review applications for opt-in units and respond in writing to the designated representative within 30 business days. The Administrator will authorize the unit to participate in the Texas SO_2 Trading Program if the provisions of paragraphs (b)(1) and (2) of this section are satisfied.

(4) Following submission of an opt-in application and authorization in accordance with paragraphs (b)(2) and (3) of this section, the unit shall be a Texas SO_2 Trading Program unit, and the source that includes the unit shall be a Texas SO_2 Trading Program source, subject to the requirements of this subpart starting on the next January 1. The unit shall remain subject to the requirements of this subpart for the life of the source, with the exception for retired units under 40 CFR 97.905.

(5) Opt-in units shall receive allowance allocations as provided in paragraph §97.911(b). These allocations shall be recorded into a source's compliance account per the recordation schedule in §97.921.

(6) The Administrator will maintain a publicly accessible record of all units that become Texas SO_2 Trading Program units under paragraph (b) of this section and of all allocations of

allowances to such units. Such public access may be provided through posting of information on a website.

§ 97.905 Retired unit exemptions.

(a)(1) Any Texas SO_2 Trading Program unit that is permanently retired shall be exempt from 97.906(b) and (c)(1), 97.924, and 97.930 through 97.935.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the Texas SO_2 Trading Program unit is permanently retired. Within 30 days of the unit's permanent retirement, the designated representative shall submit a statement to the Administrator. The statement shall state, in a format prescribed by the Administrator, that the unit was permanently retired on a specified date and will comply with the requirements of paragraph (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any SO_2, starting on the date that the exemption takes effect.

(2) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain, at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(3) The owners and operators and, to the extent applicable, the designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the

Texas SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section shall lose its exemption on the first date on which the unit resumes operation. A retired unit that resumes operation will not receive an allowance allocation under §97.911. The unit may receive allowances from the Supplemental Allowance Pool pursuant to 40 CFR 97.912. All other provisions of Subpart FFFFF regarding monitoring, reporting, recordkeeping and compliance will apply on the first date on which the unit resumes operation.

§ 97.906 General provisions.

(a) *Designated representative requirements.* The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.913 through 97.918.

(b) *Emissions monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the designated representative, of each Texas SO_2 Trading Program source and each Texas SO_2 Trading Program unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.930 through 97.935.

(2) The emissions data determined in accordance with §§97.930 through 97.935 shall be used to calculate allocations of Texas SO_2 Trading Program allowances under §97.912 and to determine compliance with the Texas SO_2 Trading Program emissions limitation under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location

determined in accordance with §§97.930 through 97.935 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero and any fraction of a ton greater than or equal to 0.50 being deemed to be a whole ton.

(c) *SO_2 emissions requirements*. (1) *Texas SO_2 Trading Program emissions limitation.* (i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each Texas SO_2 Trading Program source and each Texas SO_2 Trading Program unit at the source shall hold, in the source's compliance account, Texas SO_2 Trading Program allowances available for deduction for such control period under §97.924(a) in an amount not less than the tons of total SO_2 emissions for such control period from all Texas SO_2 Trading Program units at the source.

(ii) If total SO_2 emissions during a control period in a given year from the Texas SO_2 Trading Program units at a Texas SO_2 Trading Program source are in excess of the Texas SO_2 Trading Program emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each Texas SO_2 Trading Program unit at the source shall hold the Texas SO_2 Trading Program allowances required for deduction under §97.924(d); and

(B) The owners and operators of the source and each Texas SO_2 Trading Program unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) *Compliance periods.* A Texas SO_2 Trading Program unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of

January 1, 2019 or the deadline for meeting the unit's monitor certification requirements under §97.930(b) and for each control period thereafter.

(3) *Vintage of Texas SO_2 Trading Program allowances held for compliance.* (i) A Texas SO_2 Trading Program allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a Texas SO_2 Trading Program allowance that was allocated for such control period or a control period in a prior year.

(ii) A Texas SO_2 Trading Program allowance held for compliance with the requirements under paragraph (c)(1)(ii)(A) of this section for a control period in a given year must be a Texas SO_2 Trading Program allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(4) *Allowance Management System requirements.* Each Texas SO_2 Trading Program allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(5) *Limited authorization.* A Texas SO_2 Trading Program allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the Texas SO_2 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(6) *Property right.* A Texas SO_2 Trading Program allowance does not constitute a property right.

(d) *Title V permit requirements.* (1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of Texas SO_2 Trading Program allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO_2 emissions using a continuous emission monitoring system (under subpart B of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.930 through 97.935 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) *Additional recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of each Texas SO_2 Trading Program source and each Texas SO_2 Trading Program unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under §97.916 for the designated representative for the source and each Texas SO_2 Trading Program unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.916 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the Texas SO_2 Trading Program.

(2) The designated representative of a Texas SO_2 Trading Program source and each Texas SO_2 Trading Program unit at the source shall make all submissions required under the Texas SO_2 Trading Program, except as provided in §97.918. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) *Liability*. (1) Any provision of the Texas SO_2 Trading Program that applies to a Texas SO_2 Trading Program source or the designated representative of a Texas SO_2 Trading Program source shall also apply to the owners and operators of such source and of the Texas SO_2 Trading Program units at the source.

(2) Any provision of the Texas SO_2 Trading Program that applies to a Texas SO_2 Trading Program unit or the designated representative of a Texas SO_2 Trading Program unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the Texas SO_2 Trading Program or exemption under §97.905 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a Texas SO_2 Trading Program source or Texas SO_2 Trading Program unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 97.907 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the Texas SO_2 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the Texas SO_2 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the Texas SO_2 Trading Program, is not a business day, the time period shall be extended to the next business day.

§ 97.908 Administrative appeal procedures.

The administrative appeal procedures for decisions of the Administrator under the Texas SO_2 Trading Program are set forth in part 78 of this chapter.

§ 97.909 [RESERVED]

§ 97.910 Texas SO_2 Trading Program and Supplemental Allowance Pool Budgets.

(a) The budgets for the Texas SO_2 Trading Program and Supplemental Allowance Pool for the control periods in 2019 and thereafter are as follows:

(1) The Texas SO_2 Trading Program budget for the control period in 2019 and each future control period is 238,393 tons.

(2) The Texas SO_2 Trading Program Supplemental Allowance Pool budget for the control period in 2019 and each future control period is 10,000 tons.

(b) [reserved]

§ 97.911 Texas SO_2 Trading Program allowance allocations.

(a)(1) Except as provided in paragraph (a)(2) of this section, Texas SO_2 Trading Program allowances from the Texas SO_2 Trading Program budget will be allocated, for the control periods in 2019 and each year thereafter, as provided in the following table:

Texas SO_2 Trading Program Units	ORIS CODE	Texas SO_2 Trading Program Allocation
Big Brown Unit 1	3497	8,473
Big Brown Unit 2	3497	8,559
Coleto Creek Unit 1	6178	9,057
Fayette / Sam Seymour Unit 1	6179	7,979
Fayette / Sam Seymour Unit 2	6179	8,019
Graham Unit 2	3490	226
H W Pirkey Power Plant Unit 1	7902	8,882
Harrington Unit 061B	6193	5,361
Harrington Unit 062B	6193	5,255
Harrington Unit 063B	6193	5,055
JT Deely Unit 1	6181	6,170
JT Deely Unit 2	6181	6,082
Limestone Unit 1	298	12,081
Limestone Unit 2	298	12,293
Martin Lake Unit 1	6146	12,024
Martin Lake Unit 2	6146	11,580
Martin Lake Unit 3	6146	12,236

Monticello Unit 1	6147	8,598
Monticello Unit 2	6147	8,795
Monticello Unit 3	6147	12,216
Newman Unit 2	3456	1
Newman Unit 3	3456	1
Newman Unit 4	3456	2
Sandow Unit 4	6648	8,370
Sommers Unit 1	3611	55
Sommers Unit 2	3611	7
Stryker Unit ST2	3504	145
Tolk Station Unit 171B	6194	6,900
Tolk Station Unit 172B	6194	7,062
WA Parish Unit WAP4	3470	3
WA Parish Unit WAP5	3470	9,580
WA Parish Unit WAP6	3470	8,900
WA Parish Unit WAP7	3470	7,653
Welsh Power Plant Unit 1	6139	6,496
Welsh Power Plant Unit 2	6139	7,050
Welsh Power Plant Unit 3	6139	7,208
Wilkes Unit 1	3478	14
Wilkes Unit 2	3478	2
Wilkes Unit 3	3478	3

(2) Notwithstanding paragraph (a)(1) of this section, if a unit provided an allocation pursuant to the table in paragraph (a)(1) of this section does not operate, starting after 2018, during the control period in two consecutive years, such unit will not be allocated the Texas SO_2 Trading Program allowances provided in paragraph (a)(1) of this section for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year. All Texas SO_2 Trading Program allowances that would otherwise have been allocated to such unit will be allocated under the Texas Supplemental Allowance Pool under 40 CFR 97.912.

(b)(1) A unit that becomes a Texas SO_2 Trading Program unit pursuant to §97.904(b) will receive an allocation of Texas SO_2 Trading Program allowances equal to the SO_2 allocation shown for the unit in the table referenced in §97.404(b)(1) (ignoring the years shown in the column headings in the table) for the control period in each year while the unit is a Texas SO_2

Trading Program unit, provided that the unit has operated during the calendar year immediately preceding the year of each such control period.

(2) If a unit that becomes a Texas SO_2 Trading Program unit pursuant to §97.904(b) does not operate during a given calendar year, no Texas SO_2 Trading Program allowances will be allocated to that unit for the control period in the following year or any subsequent year, nor will any allowances that would otherwise have been allocated to such unit under paragraph (b)(1) of this section be made available for use by any other unit under the Texas Supplemental Allowance Pool or otherwise.

(c) *Units incorrectly allocated Texas SO_2 Trading Program allowances.* (1) For each control period in 2019 and thereafter, if the Administrator determines that Texas SO_2 Trading Program allowances were incorrectly allocated under paragraph (a) or (b) of this section, or under a provision of a SIP revision approved by the Administrator, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such Texas SO_2 Trading Program allowances under §97.921.

(3) If the Administrator already recorded such Texas SO_2 Trading Program allowances under §97.921 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under §97.924(b) for such control period, then the Administrator will deduct from the account in which such Texas SO_2 Trading Program allowances were recorded an amount of Texas SO_2 Trading Program allowances allocated for the same or a prior control period equal to the amount of such already recorded Texas SO_2 Trading Program allowances. The authorized account representative shall

ensure that there are sufficient Texas SO_2 Trading Program allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such Texas SO_2 Trading Program allowances under §97.921 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under §97.924(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded Texas SO_2 Trading Program allowances.

(5) With regard to the Texas SO_2 Trading Program allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (a) of this section, the Administrator will transfer such Texas SO_2 Trading Program allowances to the Texas Supplemental Allowance Pool under 40 CFR 97.912. With regard to the Texas SO_2 Trading Program allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section for a recipient under paragraph (b) of this section, the Administrator will retire such Texas SO_2 Trading Program allowances.

§ 97.912 Texas SO_2 Trading Program Supplemental Allowance Pool.

(a) For each control period in 2019 and thereafter, the Administrator will allocate Texas SO2 Trading Program allowances from the Texas SO2 Trading Program Supplemental Allowance Pool as follows:

(1) No later than February 15, 2020 and each subsequent February 15, the Administrator will review all the quarterly SO2 emissions reports provided under § 97.934(d) for each Texas SO2 Trading Program unit for the previous control period. The Administrator will identify each

Texas SO2 Trading Program source for which the total amount of emissions reported for the units at the source for that control period exceeds the total amount of allowances allocated to the units at the source for that control period under § 97.911.

(2) For each Texas SO2 Trading Program source identified under paragraph (a)(1) of this section, the Administrator will calculate the amount by which the total amount of reported emissions for that control period exceeds the total amount of allowances allocated for that control period under § 97.911.

(3)(i) For Coleto Creek (ORIS 6178), if the source is identified under paragraph (a)(1) of this section, the Administrator will allocate and record in the source's compliance account an amount of allowances from the Supplemental Allowance Pool equal to the lesser of the amount calculated for the source under paragraph (a)(2) of this section or the total number of allowances in the Supplemental Allowance Pool available for allocation under paragraph (b) of this section.

(ii) For any Texas SO2 Trading Program sources identified under paragraph (a)(1) of this section other than Coleto Creek (ORIS 6178), the Administrator will allocate and record allowances from the Supplemental Allowance Pool as follows:

(A) If the total for all such sources of the amounts calculated under paragraph (a)(2) of this section is less than or equal to the total number of allowances in the Supplemental Allowance Pool available for allocation under paragraph (b) of this section that remain after any allocation under paragraph (a)(3)(i) of this section, then the Administrator will allocate and record in the compliance account for each such source an amount of allowances from the Supplemental Allowance Pool equal to the amount calculated for the source under paragraph (a)(2) of this section.

(B) If the total for all such sources of the amounts calculated under paragraph (a)(2) of this section is greater than the total number of allowances in the Supplemental Allowance Pool available for allocation under paragraph (b) of this section that remain after any allocation under paragraph (a)(3)(i) of this section, then the Administrator will calculate each such source's allocation of allowances from the Supplemental Allowance Pool by dividing the amount calculated under paragraph (a)(2) of this section for the source by the sum of the amounts calculated under paragraph (a)(2) of this section for all such sources, then multiplying by the number of allowances in the Supplemental Allowance Pool available for allocation under paragraph (b) of this section that remain after any allocation under paragraph (a)(3)(i) of this section and rounding to the nearest allowance. The Administrator will then record the calculated allocations of allowances in the applicable compliance accounts.

(iii) Any unallocated allowances remaining in the Supplemental Allowance Pool after the allocations determined under paragraphs (a)(3)(i) and (ii) of this section will be maintained in the Supplemental Allowance Pool. These allowances will be available for allocation by the Administrator in subsequent control periods to the extent consistent with paragraph (b) of this section.

(4) The Administrator will notify the designated representative of each Texas SO2 Trading Program source when the allowances from the Supplemental Allowance Pool have been recorded.

(b) The total amount of allowances in the Texas SO2 Trading Program Supplemental Allowance Pool available for allocation for a control period is equal to the sum of the Texas SO2 Trading Program Supplemental Allowance Pool budget under § 97.910(a)(2), any allowances from retired units pursuant to § 97.911(a)(2) and from corrections pursuant to § 97.911(c)(5), and any allowances maintained in the Supplemental Allowance Pool pursuant to paragraph (a)(3)(iii) of this section, but cannot exceed by more than 44,711 tons the sum of the budget provided under § 97.910(a)(2) and any portion of the budget provided under § 97.910(a)(1) not otherwise allocated for that control period under § 97.911(a)(1). If the number of allowances in the Supplemental Allowance Pool exceeds this level then the Administrator may only allocate allowances up to this level for the control period.

§ 97.913 Authorization of designated representative and alternate designated representative.

(a) Except as provided under §97.915, each Texas SO_2 Trading Program source, including all Texas SO_2 Trading Program units at the source, shall have one and only one designated representative, with regard to all matters under the Texas SO_2 Trading Program.

(1) The designated representative shall be selected by an agreement binding on the owners and operators of the source and all Texas SO_2 Trading Program units at the source and shall act in accordance with the certification statement in §97.916(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under §97.916:

(i) The designated representative shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the source and each Texas SO_2 Trading Program unit at the source in all matters pertaining to the Texas SO_2 Trading Program, notwithstanding any agreement between the designated representative and such owners and operators; and

(ii) The owners and operators of the source and each Texas SO_2 Trading Program unit at the source shall be bound by any decision or order issued to the designated representative by the Administrator regarding the source or any such unit.

(b) Except as provided under §97.915, each Texas SO_2 Trading Program source may have one and only one alternate designated representative, who may act on behalf of the designated representative. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) The alternate designated representative shall be selected by an agreement binding on the owners and operators of the source and all Texas SO_2 Trading Program units at the source and shall act in accordance with the certification statement in §97.916(a)(4)(iii).

(2) Upon and after receipt by the Administrator of a complete certificate of representation under §97.916,

(i) The alternate designated representative shall be authorized;

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative; and

(iii) The owners and operators of the source and each Texas SO_2 Trading Program unit at the source shall be bound by any decision or order issued to the alternate designated representative by the Administrator regarding the source or any such unit.

(c) Except in this section, §97.902, and §§97.914 through 97.918, whenever the term “designated representative” is used in this subpart, the term shall be construed to include the designated representative or any alternate designated representative.

§ 97.914 Responsibilities of designated representative and alternate designated representative.

(a) Except as provided under §97.918 concerning delegation of authority to make submissions, each submission under the Texas SO_2 Trading Program shall be made, signed, and certified by the designated representative or alternate designated representative for each Texas SO_2 Trading Program source and Texas SO_2 Trading Program unit for which the submission is made. Each such submission shall include the following certification statement by the designated representative or alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(b) The Administrator will accept or act on a submission made for a Texas SO_2 Trading Program source or a Texas SO_2 Trading Program unit only if the submission has been made, signed, and certified in accordance with paragraph (a) of this section and §97.918.

§ 97.915 Changing designated representative and alternate designated representative; changes in owners and operators; changes in units at the source.

(a) *Changing designated representative.* The designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.916. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new designated representative and the owners and operators of the Texas SO_2 Trading Program source and the Texas SO_2 Trading Program units at the source.

(b) *Changing alternate designated representative.* The alternate designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §97.916. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate designated representative, the designated representative, and the owners and operators of the Texas SO_2 Trading Program source and the Texas SO_2 Trading Program units at the source.

(c) *Changes in owners and operators.* (1) In the event an owner or operator of a Texas SO_2 Trading Program source or a Texas SO_2 Trading Program unit at the source is not included in the list of owners and operators in the certificate of representation under §97.916, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the source or unit, and the decisions and orders of the Administrator, as if the owner or operator were included in such list.

(2) Within 30 days after any change in the owners and operators of a Texas SO_2 Trading Program source or a Texas SO_2 Trading Program unit at the source, including the addition or removal of an owner or operator, the designated representative or any alternate designated representative shall submit a revision to the certificate of representation under §97.916 amending the list of owners and operators to reflect the change.

(d) *Changes in units at the source.* Within 30 days of any change in which units are located at a Texas SO_2 Trading Program source (including the addition (see §97.904(b)) or removal of a unit), the designated representative or any alternate designated representative shall submit a certificate of representation under §97.916 amending the list of units to reflect the change.

(1) If the change is the addition of a unit (see §97.904(b)) that operated (other than for purposes of testing by the manufacturer before initial installation) before being located at the source, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity from whom the unit was purchased or otherwise obtained (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was purchased or otherwise obtained, and the date on which the unit became located at the source.

(2) If the change is the removal of a unit, then the certificate of representation shall identify, in a format prescribed by the Administrator, the entity to which the unit was sold or that otherwise obtained the unit (including name, address, telephone number, and facsimile number (if any)), the date on which the unit was sold or otherwise obtained, and the date on which the unit became no longer located at the source.

§ 97.916 Certificate of representation.

(a) A complete certificate of representation for a designated representative or an alternate designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the Texas SO_2 Trading Program source, and each Texas SO_2 Trading Program unit at the source, for which the certificate of representation is submitted, including source name, source category and NAICS code (or, in the absence of a NAICS code, an equivalent code), State, plant code, county, latitude and longitude, unit identification number and type, identification number and nameplate capacity (in MWe, rounded to the nearest tenth) of each generator served by each such unit, and actual date of commencement of commercial operation, and a statement of whether such source is located in Indian country.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the Texas SO_2 Trading Program source and of each Texas SO_2 Trading Program unit at the source.

(4) The following certification statements by the designated representative and any alternate designated representative—

(i) "I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the source and each Texas SO_2 Trading Program unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the Texas SO_2 Trading Program on behalf of the owners and operators of the source and of each Texas SO_2 Trading Program unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the source or unit."

(iii) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a Texas SO_2 Trading Program unit, or where a utility or industrial customer purchases power from a Texas SO_2 Trading Program unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each Texas SO_2 Trading Program unit at the source; and Texas SO_2 Trading Program allowances and proceeds of transactions involving Texas SO_2 Trading Program allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of Texas SO_2 Trading Program allowances by contract, Texas SO_2 Trading Program allowances and proceeds of transactions involving Texas SO_2 Trading Program allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(b) Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

§ 97.917 Objections concerning designated representative and alternate designated representative.

(a) Once a complete certificate of representation under §97.916 has been submitted and received, the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §97.916 is received by the Administrator.

(b) Except as provided in paragraph (a) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of a designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative or the finality of any decision or order by the Administrator under the Texas SO_2 Trading Program.

(c) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative, including private legal disputes concerning the proceeds of Texas SO_2 Trading Program allowance transfers.

§ 97.918 Delegation by designated representative and alternate designated representative.

(a) A designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(b) An alternate designated representative may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(c) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (a) or (b) of this section, the designated representative or alternate designated representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(1) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative;

(2) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an "agent");

(3) For each such natural person, a list of the type or types of electronic submissions under paragraph (a) or (b) of this section for which authority is delegated to him or her; and

(4) The following certification statements by such designated representative or alternate designated representative:

(i) "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.918(d) shall be deemed to be an electronic submission by me."

(ii) "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.918(d), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.918 is terminated.".

(d) A notice of delegation submitted under paragraph (c) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such designated representative or alternate designated representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(e) Any electronic submission covered by the certification in paragraph (c)(4)(i) of this section and made in accordance with a notice of delegation effective under paragraph (d) of this section shall be deemed to be an electronic submission by the designated representative or alternate designated representative submitting such notice of delegation.

§ 97.919 [RESERVED]

§ 97.920 Establishment of compliance accounts and general accounts.

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under §97.916, the Administrator will establish a compliance account for the Texas SO_2 Trading Program source for which the certificate of representation was submitted, unless the source already has a compliance account. The designated representative and any alternate designated representative of the source shall be the authorized account representative and the alternate authorized account representative respectively of the compliance account.

(b) *General accounts*—(1) *Application for general account.* (i) Any person may apply to open a general account, for the purpose of holding and transferring Texas SO_2 Trading Program allowances, by submitting to the Administrator a complete application for a general account. Such application shall designate one and only one authorized account representative and may designate one and only one alternate authorized account representative who may act on behalf of the authorized account representative.

(A) The authorized account representative and alternate authorized account representative shall be selected by an agreement binding on the persons who have an ownership interest with respect to Texas SO_2 Trading Program allowances held in the general account.

(B) The agreement by which the alternate authorized account representative is selected shall include a procedure for authorizing the alternate authorized account representative to act in lieu of the authorized account representative.

(ii) A complete application for a general account shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the authorized account representative and any alternate authorized account representative;

(B) An identifying name for the general account;

(C) A list of all persons subject to a binding agreement for the authorized account representative and any alternate authorized account representative to represent their ownership interest with respect to the Texas SO_2 Trading Program allowances held in the general account;

(D) The following certification statement by the authorized account representative and any alternate authorized account representative: "I certify that I was selected as the authorized account representative or the alternate authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to Texas SO_2 Trading Program allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the Texas SO_2 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Administrator regarding the general account."

(E) The signature of the authorized account representative and any alternate authorized account representative and the dates signed.

(iii) Unless otherwise required by the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of authorized account representative and alternate authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section, the Administrator will establish a general account for the person or persons for whom the application is submitted, and upon and after such receipt by the Administrator:

(A) The authorized account representative of the general account shall be authorized and shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to Texas SO_2 Trading Program allowances held in the general account in all matters pertaining to the Texas SO_2 Trading Program, notwithstanding any agreement between the authorized account representative and such person.

(B) Any alternate authorized account representative shall be authorized, and any representation, action, inaction, or submission by any alternate authorized account representative shall be deemed to be a representation, action, inaction, or submission by the authorized account representative.

(C) Each person who has an ownership interest with respect to Texas SO_2 Trading Program allowances held in the general account shall be bound by any decision or order issued to the authorized account representative or alternate authorized account representative by the Administrator regarding the general account.

(ii) Except as provided in paragraph (b)(5) of this section concerning delegation of authority to make submissions, each submission concerning the general account shall be made, signed, and certified by the authorized account representative or any alternate authorized account representative for the persons having an ownership interest with respect to Texas SO_2 Trading Program allowances held in the general account. Each such submission shall include the following certification statement by the authorized account representative or any alternate authorized account representative: “I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the Texas SO_2 Trading Program allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) Except in this section, whenever the term "authorized account representative" is used in this subpart, the term shall be construed to include the authorized account representative or any alternate authorized account representative.

(3) *Changing authorized account representative and alternate authorized account representative; changes in persons with ownership interest.* (i) The authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new authorized account representative and the persons with an ownership interest with respect to the Texas SO_2 Trading Program allowances in the general account.

(ii) The alternate authorized account representative of a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate authorized account representative, the authorized account representative, and the persons with an ownership interest with respect to the Texas SO_2 Trading Program allowances in the general account.

(iii)(A) In the event a person having an ownership interest with respect to Texas SO_2 Trading Program allowances in the general account is not included in the list of such persons in the application for a general account, such person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the authorized account representative and any alternate authorized account representative of the account, and the decisions and orders of the Administrator, as if the person were included in such list.

(B) Within 30 days after any change in the persons having an ownership interest with respect to Texas SO_2 Trading Program allowances in the general account, including the addition or removal of a person, the authorized account representative or any alternate authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the Texas SO_2 Trading Program allowances in the general account to include the change.

(4) *Objections concerning authorized account representative and alternate authorized account representative.* (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(4)(i) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account shall affect any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative or the finality of any decision or order by the Administrator under the Texas SO_2 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the authorized account representative or any alternate authorized account representative of a general account, including private legal disputes concerning the proceeds of Texas SO_2 Trading Program allowance transfers.

(5) *Delegation by authorized account representative and alternate authorized account representative.* (i) An authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(ii) An alternate authorized account representative of a general account may delegate, to one or more natural persons, his or her authority to make an electronic submission to the Administrator provided for or required under this subpart.

(iii) In order to delegate authority to a natural person to make an electronic submission to the Administrator in accordance with paragraph (b)(5)(i) or (ii) of this section, the authorized account representative or alternate authorized account representative, as appropriate, must submit to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(A) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of such authorized account representative or alternate authorized account representative;

(B) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such natural person (referred to in this section as an "agent");

(C) For each such natural person, a list of the type or types of electronic submissions under paragraph (b)(5)(i) or (ii) of this section for which authority is delegated to him or her;

(D) The following certification statement by such authorized account representative or alternate authorized account representative: "I agree that any electronic submission to the Administrator that is made by an agent identified in this notice of delegation and of a type listed for such agent in this notice of delegation and that is made when I am an authorized account representative or alternate authorized account representative, as appropriate, and before this notice of delegation is superseded by another notice of delegation under 40 CFR 97.920(b)(5)(iv) shall be deemed to be an electronic submission by me."; and

(E) The following certification statement by such authorized account representative or alternate authorized account representative: "Until this notice of delegation is superseded by another notice of delegation under 40 CFR 97.920(b)(5)(iv), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under 40 CFR 97.920(b)(5) is terminated."

(iv) A notice of delegation submitted under paragraph (b)(5)(iii) of this section shall be effective, with regard to the authorized account representative or alternate authorized account representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of a superseding notice of delegation submitted by such authorized account representative or alternate authorized account representative, as appropriate. The superseding notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(v) Any electronic submission covered by the certification in paragraph (b)(5)(iii)(D) of this section and made in accordance with a notice of delegation effective under paragraph (b)(5)(iv) of this section shall be deemed to be an electronic submission by the authorized account representative or alternate authorized account representative submitting such notice of delegation.

(6) *Closing a general account.* (i) The authorized account representative or alternate authorized account representative of a general account may submit to the Administrator a request to close the account. Such request shall include a correctly submitted Texas SO_2 Trading Program allowance transfer under §97.922 for any Texas SO_2 Trading Program allowances in the account to one or more other Allowance Management System accounts.

(ii) If a general account has no Texas SO_2 Trading Program allowance transfers to or from the account for a 12-month period or longer and does not contain any Texas SO_2 Trading Program allowances, the Administrator may notify the authorized account representative for the account that the account will be closed after 30 days after the notice is sent. The account will be closed after the 30-day period unless, before the end of the 30-day period, the Administrator receives a correctly submitted Texas SO_2 Trading Program allowance transfer under §97.922 to the account or a statement submitted by the authorized account representative or alternate authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

(d) *Responsibilities of authorized account representative and alternate authorized account representative.* After the establishment of a compliance account or general account, the

Administrator will accept or act on a submission pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of Texas SO_2 Trading Program allowances in the account, only if the submission has been made, signed, and certified in accordance with §§97.914(a) and 97.918 or paragraphs (b)(2)(ii) and (b)(5) of this section.

§ 97.921 Recordation of Texas SO_2 Trading Program allowance allocations.

(a) By November 1, 2018, the Administrator will record in each Texas SO_2 Trading Program source's compliance account the Texas SO_2 Trading Program allowances allocated to the Texas SO_2 Trading Program units at the source in accordance with §97.911(a) for the control periods in 2019, 2020, 2021, and 2022. The Administrator may delay recordation of Texas SO_2 Trading Program allowances for the specified control periods if the State of Texas submits a SIP revision before the recordation deadline.

(b) By July 1, 2019 and July 1 of each year thereafter, the Administrator will record in each Texas SO_2 Trading Program source's compliance account the Texas SO_2 Trading Program allowances allocated to the Texas SO_2 Trading Program units at the source in accordance with §97.911(a) for the control period in the fourth year after the year of the applicable recordation deadline under this paragraph. The Administrator may delay recordation of the Texas SO_2 Trading Program allowances for the applicable control periods if the State of Texas submits a SIP revision by May 1 of the year of the applicable recordation deadline under this paragraph.

(c) By February 15, 2020, and February 15 of each year thereafter, the Administrator will record in each Texas SO_2 Trading Program source's compliance account the allowances allocated from the Texas SO_2 Trading Program Supplemental Allowance Pool in accordance with §97.912 for the control period in the year of the applicable recordation deadline under this paragraph, .

(d) By July 1, 2019 and July 1 of each year thereafter, the Administrator will record in each Texas SO_2 Trading Program source's compliance account the Texas SO_2 Trading Program allowances allocated to the Texas SO_2 Trading Program units at the source in accordance with §97.911(b).

(e) When recording the allocation of Texas SO_2 Trading Program allowances to a Texas SO_2 Trading Program unit in an Allowance Management System account, the Administrator will assign each Texas SO_2 Trading Program allowance a unique identification number that will include digits identifying the year of the control period for which the Texas SO_2 Trading Program allowance is allocated.

§ 97.922 Submission of Texas SO_2 Trading Program allowance transfers.

(a) An authorized account representative seeking recordation of a Texas SO_2 Trading Program allowance transfer shall submit the transfer to the Administrator.

(b) A Texas SO_2 Trading Program allowance transfer shall be correctly submitted if:

(1) The transfer includes the following elements, in a format prescribed by the Administrator:

(i) The account numbers established by the Administrator for both the transferor and transferee accounts;

(ii) The serial number of each Texas SO_2 Trading Program allowance that is in the transferor account and is to be transferred; and

(iii) The name and signature of the authorized account representative of the transferor account and the date signed; and

(2) When the Administrator attempts to record the transfer, the transferor account includes each Texas SO_2 Trading Program allowance identified by serial number in the transfer.

§ 97.923 Recordation of Texas SO_2 Trading Program allowance transfers.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a Texas SO_2 Trading Program allowance transfer that is correctly submitted under §97.922, the Administrator will record a Texas SO_2 Trading Program allowance transfer by moving each Texas SO_2 Trading Program allowance from the transferor account to the transferee account as specified in the transfer.

(b) A Texas SO_2 Trading Program allowance transfer to or from a compliance account that is submitted for recordation after the allowance transfer deadline for a control period and that includes any Texas SO_2 Trading Program allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions from such compliance account under §97.924 for the control period immediately before such allowance transfer deadline.

(c) Where a Texas SO_2 Trading Program allowance transfer is not correctly submitted under §97.922, the Administrator will not record such transfer.

(d) Within 5 business days of recordation of a Texas SO_2 Trading Program allowance transfer under paragraphs (a) and (b) of the section, the Administrator will notify the authorized account representatives of both the transferor and transferee accounts.

(e) Within 10 business days of receipt of a Texas SO_2 Trading Program allowance transfer that is not correctly submitted under §97.922, the Administrator will notify the authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

§ 97.924 Compliance with Texas SO_2 Trading Program emissions limitations.

(a) *Availability for deduction for compliance.* Texas SO_2 Trading Program allowances are available to be deducted for compliance with a source's Texas SO_2 Trading Program emissions limitation for a control period in a given year only if the Texas SO_2 Trading Program allowances:

(1) Were allocated for such control period or a control period in a prior year; and

(2) Are held in the source's compliance account as of the allowance transfer deadline for such control period.

(b) *Deductions for compliance.* After the recordation, in accordance with §97.923, of Texas SO_2 Trading Program allowance transfers submitted by the allowance transfer deadline for a control period in a given year, the Administrator will deduct from each source's compliance account Texas SO_2 Trading Program allowances available under paragraph (a) of this section in order to determine whether the source meets the Texas SO_2 Trading Program emissions limitation for such control period, as follows:

(1) Until the amount of Texas SO_2 Trading Program allowances deducted equals the number of tons of total SO_2 emissions from all Texas SO_2 Trading Program units at the source for such control period; or

(2) If there are insufficient Texas SO_2 Trading Program allowances to complete the deductions in paragraph (b)(1) of this section, until no more Texas SO_2 Trading Program allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of Texas* SO_2 *Trading Program allowances by serial number.* The authorized account representative for a source's compliance account may request that specific Texas SO_2 Trading Program allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in a given year in accordance with paragraph (b) or (d) of this section. In order to be complete, such request shall be submitted to the Administrator by the allowance transfer deadline for such control period and include, in a format prescribed by the Administrator, the identification of the Texas SO_2 Trading Program source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct Texas SO_2 Trading Program allowances under paragraph (b) or (d) of this section from the source's compliance account in accordance with a complete request under paragraph (c)(1) of this section or, in the absence of such request or in the case of identification of an insufficient amount of Texas SO_2 Trading Program allowances in such request, on a first-in, first-out accounting basis in the following order:

(i) Any Texas SO_2 Trading Program allowances that were recorded in the compliance account pursuant to §97.921 and not transferred out of the compliance account, in the order of recordation; and then

(ii) Any other Texas SO_2 Trading Program allowances that were transferred to and recorded in the compliance account pursuant to this subpart, in the order of recordation.

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the Texas SO_2 Trading Program source has excess emissions, the Administrator will deduct from the source's compliance account an amount of Texas SO_2 Trading Program allowances, allocated for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to three times the number of tons of the source's excess emissions.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraphs (b) and (d) of this section.

§ 97.925 [RESERVED]

§ 97.926 Banking.

(a) A Texas SO_2 Trading Program allowance may be banked for future use or transfer in a compliance account or general account in accordance with paragraph (b) of this section.

(b) Any Texas SO_2 Trading Program allowance that is held in a compliance account or a general account will remain in such account unless and until the Texas SO_2 Trading Program allowance is deducted or transferred under §97.911(c), §97.923, §97.924, §97.927, or §97.928.

§ 97.927 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Management System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 97.928 Administrator's action on submissions.

(a) The Administrator may review and conduct independent audits concerning any submission under the Texas SO_2 Trading Program and make appropriate adjustments of the information in the submission.

(b) The Administrator may deduct Texas SO_2 Trading Program allowances from or transfer Texas SO_2 Trading Program allowances to a compliance account, based on the information in a submission, as adjusted under paragraph (a) of this section, and record such deductions and transfers.

§ 97.929 [RESERVED]

§ 97.930 General monitoring, recordkeeping, and reporting requirements.

The owners and operators, and to the extent applicable, the designated representative, of a Texas SO_2 Trading Program unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and subparts F and G of part 75 of this chapter. For purposes of applying such requirements, the definitions in §97.902 and in §72.2 of this chapter shall apply, the terms "affected unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") in part 75 of this chapter shall be deemed to refer to the terms "Texas SO_2 Trading Program unit," "designated representative," and "continuous emission monitoring system" (or "CEMS") respectively as defined in §97.902. The owner or operator of a unit that is not a Texas SO_2 Trading Program unit but that is monitored under §75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a Texas SO_2 Trading Program unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each Texas SO_2 Trading Program unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO_2 mass emissions and individual unit heat input (including all systems required to monitor SO_2 concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under §97.931 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* Except as provided in paragraph (e) of this section, the owner or operator of a Texas SO_2 Trading Program unit shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the later of the following dates and shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after:

(1) For a Texas SO_2 Trading Program unit under §97.904(a), January 1, 2019; or

(2) For a Texas SO_2 Trading Program unit under §97.904(b), January 1 of the first control period for which the unit is a Texas SO_2 Trading Program unit.

(3) The owner or operator of a Texas SO_2 Trading Program unit for which construction of a new stack or flue or installation of add-on SO_2 emission controls is completed after the applicable deadline under paragraph (b)(1) or (2) of this section shall meet the requirements of §75.4(e)(1) through (4) of this chapter, except that:

(i) Such requirements shall apply to the monitoring systems required under §97.930 through §97.935, rather than the monitoring systems required under part 75 of this chapter;

(ii) SO_2 concentration, stack gas moisture content, stack gas volumetric flow rate, and O2 or CO2 concentration data shall be determined and reported, rather than the data listed in §75.4(e)(2) of this chapter; and

(iii) Any petition for another procedure under §75.4(e)(2) of this chapter shall be submitted under §97.935, rather than §75.66 of this chapter.

(c) *Reporting data.* The owner or operator of a Texas SO_2 Trading Program unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO_2 concentration, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO_2 mass emissions and heat input in accordance with §75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(d) *Prohibitions.* (1) No owner or operator of a Texas SO_2 Trading Program unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with §97.935.

(2) No owner or operator of a Texas SO_2 Trading Program unit shall operate the unit so as to discharge, or allow to be discharged, SO_2 to the atmosphere without accounting for all such SO_2 in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a Texas SO_2 Trading Program unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2 mass discharged into the atmosphere or heat input, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a Texas SO_2 Trading Program unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §97.905 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this subpart and part 75 of this chapter, by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §97.931(d)(3)(i).

(e) *Long-term cold storage.* The owner or operator of a Texas SO_2 Trading Program unit is subject to the applicable provisions of §75.4(d) of this chapter concerning units in long-term cold storage.

§ 97.931 Initial monitoring system certification and recertification procedures.

(a) The owner or operator of a Texas SO_2 Trading Program unit shall be exempt from the initial certification requirements of this section for a monitoring system under §97.930(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendices B and D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §97.930(a)(1) that is exempt from initial certification requirements under paragraph (a) of this section.

(c) [Reserved]

(d) Except as provided in paragraph (a) of this section, the owner or operator of a Texas SO_2 Trading Program unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (*i.e.*, a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under §97.930(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under §75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under §97.930(a)(1) (including the automated data acquisition and

handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §97.930(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under §97.930(a)(1) that may significantly affect the ability of the system to accurately measure or record SO_2 mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under §97.930(a)(1) is subject to the recertification requirements in §75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* For initial certification of a continuous monitoring system under §97.930(a)(1), paragraphs (d)(3)(i) through (v) of this section apply. For recertifications of such monitoring systems, paragraphs (d)(3)(i) through (iv)

of this section and the procedures in §75.20(b)(5) and (g)(7) of this chapter (in lieu of the procedures in paragraph (d)(3)(v) of this section) apply, provided that in applying paragraphs (d)(3)(i) through (iv) of this section, the words "certification" and "initial certification" are replaced by the word "recertification" and the word "certified" is replaced by with the word "recertified".

(i) *Notification of certification.* The designated representative shall submit to the appropriate EPA Regional Office and the Administrator written notice of the dates of certification testing, in accordance with §97.933.

(ii) *Certification application.* The designated representative shall submit to the Administrator a certification application for each monitoring system. A complete certification application shall include the information specified in §75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the Texas SO_2 Trading Program for a period not to exceed 120 days after receipt by the Administrator of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the Administrator does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the Administrator.

(iv) *Certification application approval process.* The Administrator will issue a written notice of approval or disapproval of the certification application to the owner or operator within

120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the Administrator does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the Texas SO_2 Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the Administrator will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the Administrator will issue a written notice of incompleteness that sets a reasonable date by which the designated representative must submit the additional information required to complete the certification application. If the designated representative does not comply with the notice of incompleteness by the specified date, then the Administrator may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the Administrator will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the Administrator and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter).

(D) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with §97.932(b).

(v) *Procedures for loss of certification.* If the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), §75.20(g)(7), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved SO_2 pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO_2 and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(3) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(e) The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under §75.19 of this chapter shall meet the applicable certification and recertification requirements in §§75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in §75.20(g) of this chapter.

(f) The designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.

§ 97.932 Monitoring system out-of-control periods.

(a) *General provisions.* Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D or appendix D to part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §97.931 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the Administrator or any State or permitting authority. By issuing the notice of disapproval, the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §97.931 for each disapproved monitoring system.

§ 97.933 Notifications concerning monitoring.

The designated representative of a Texas SO_2 Trading Program unit shall submit written notice to the Administrator in accordance with §75.61 of this chapter.

§ 97.934 Recordkeeping and reporting.

(a) *General provisions.* The designated representative of a Texas SO_2 Trading Program unit shall comply with all recordkeeping and reporting requirements in paragraphs (b) through (e) of this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of §97.914(a).

(b) *Monitoring plans.* The owner or operator of a Texas SO_2 Trading Program unit shall comply with the requirements of §75.62 of this chapter.

(c) *Certification applications.* The designated representative shall submit an application to the Administrator within 45 days after completing all initial certification or recertification tests required under §97.931, including the information required under §75.63 of this chapter.

(d) *Quarterly reports.* The designated representative shall submit quarterly reports, as follows:

(1) The designated representative shall report the SO_2 mass emissions data and heat input data for a Texas SO_2 Trading Program unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with the later of:

(i) The calendar quarter covering January 1, 2019 through March 31, 2019; or

(ii) The calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §97.930(b).

(2) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.64 of this chapter.

(3) For Texas SO_2 Trading Program units that are also subject to the Acid Rain Program or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

(4) The Administrator may review and conduct independent audits of any quarterly report in order to determine whether the quarterly report meets the requirements of this subpart and part 75 of this chapter, including the requirement to use substitute data.

(i) The Administrator will notify the designated representative of any determination that the quarterly report fails to meet any such requirements and specify in such notification any corrections that the Administrator believes are necessary to make through resubmission of the quarterly report and a reasonable time period within which the designated representative must respond. Upon request by the designated representative, the Administrator may specify reasonable extensions of such time period. Within the time period (including any such extensions) specified by the Administrator, the designated representative shall resubmit the quarterly report with the corrections specified by the Administrator, except to the extent the designated representative provides information demonstrating that a specified correction is not necessary because the quarterly report already meets the requirements of this subpart and part 75 of this chapter that are relevant to the specified correction.

(ii) Any resubmission of a quarterly report shall meet the requirements applicable to the submission of a quarterly report under this subpart and part 75 of this chapter, except for the deadline set forth in paragraph (d)(2) of this section.

(e) *Compliance certification.* The designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO_2 emission controls and for all hours where SO_2 data are substituted in accordance with §75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO_2 emissions.

§ 97.935 Petitions for alternatives to monitoring, recordkeeping, or reporting requirements.

(a) The designated representative of a Texas SO_2 Trading Program unit may submit a petition under §75.66 of this chapter to the Administrator, requesting approval to apply an alternative to any requirement of §§97.930 through 97.934.

(b) A petition submitted under paragraph (a) of this section shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(1) Identification of each unit and source covered by the petition;

(2) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(3) A description and diagram of any equipment and procedures used in the proposed alternative;

(4) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and with the purposes of this subpart and part 75 of this chapter and that any adverse effect of approving the alternative will be *de minimis;* and

(5) Any other relevant information that the Administrator may require.

(c) Use of an alternative to any requirement referenced in paragraph (a) of this section is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator and that such use is in accordance with such approval.

Exhibit B

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

SIERRA CLUB, Plaintiff, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and GINA McCARTHY,[1] Administrator, United States Environmental Protection Agency, Defendants.	)	Case No.: 1:10-CV-01541-CKK

SUPPLEMENTAL NOTICE BY EPA REGARDING EPA'S SCHEDULE FOR COMPLETING FINAL ACTION ON A GOOD NEIGHBOR FEDERAL IMPLEMENTATION PLAN FOR TEXAS WITH RESPECT TO THE 1997 $PM_{2.5}$ STANDARDS

On November 15, 2016, the Court ordered EPA to supplement its October 27, 2016, Notice to indicate with more specificity than it had in previous notices when it will complete final action addressing the Act's good neighbor requirements for the 1997 $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS) with respect to emissions from Texas. *See* Docket No. 85. The Court further ordered EPA to explain in the supplement why EPA's schedule is the most expeditious schedule possible. *Id.* EPA hereby states the following:

1. As described in EPA's October 27, 2016 Notice, Janet McCabe, Acting Assistant Administrator for the Office of Air and Radiation, issued a memorandum on June 27, 2016, explaining EPA's plan for responding to the D.C. Circuit's remand of certain Cross-State Air Pollution Rule ("CSAPR") Phase 2 budgets, including the Phase 2 sulfur dioxide ("SO_2") budget

[1] Gina McCarthy is substituted for Lisa P. Jackson pursuant to Fed. R. Civ. P. 25(d).

that EPA promulgated for Texas to address the good neighbor provision for the 1997 $PM_{2.5}$ NAAQS. *See* Memo from McCabe to Air Division Directors, Regions 1-10, "The U.S. Environmental Protection Agency's Plan for Responding to the Remand of the Cross-State Air Pollution Rule Phase 2 SO_2 Budgets for Alabama, Georgia, South Carolina and Texas" (June 27, 2016) ("McCabe Memorandum"), *available at* https://www3.epa.gov/airtransport/CSAPR/pdfs/CSAPR_SO2_Remand_Memo.pdf.

2. The McCabe Memorandum explains that a state subject to a remanded CSAPR Phase 2 SO_2 budget may voluntarily choose to adopt the remanded SO_2 budget as well as the CSAPR Phase 2 budget for annual emissions of nitrogen oxides ("NO_X") into a state implementation plan ("SIP"). If such plan is approved as satisfying the state's good neighbor obligation with respect to the 1997 $PM_{2.5}$ NAAQS (and in the case of certain states, the 2006 $PM_{2.5}$ NAAQS as well), the approved SIP would automatically replace EPA's corresponding federal implementation plan ("FIP") provisions promulgated in CSAPR, and EPA would no longer have authority to promulgate a FIP addressing the good neighbor provision for those standards with respect to that state. Alternatively, for any state that does not choose to voluntarily adopt the SO_2 and annual NO_X budgets into its SIP, the McCabe Memorandum explains that EPA intends to withdraw the current FIP provisions requiring the state's sources to participate in the CSAPR trading programs for SO_2 and annual NO_X emissions and to address any remaining interstate transport obligation for those standards with respect to that state through state-specific SIP or FIP actions, as appropriate. *See* McCabe Memorandum at 3.

3. Since EPA filed its last Notice with the Court, EPA signed and published a proposed rule in response to the remand of the Texas SO_2 budget. *See* Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas, 81

Fed. Reg. 78,954 (November 10, 2016) ("Proposed Rule"). In addition to addressing the remand, the Proposed Rule proposes to address any remaining good neighbor obligation for Texas with respect to the 1997 $PM_{2.5}$ NAAQS.

4. During the time leading up to the Proposed Rule, EPA consulted with each of the four states subject to remanded CSAPR Phase 2 SO_2 budgets (Alabama, Georgia, South Carolina, and Texas) as to which option outlined in the McCabe Memorandum each state would choose. Texas conveyed that it was not choosing the option of voluntarily adopting the remanded budgets into its SIP, whereas the three other states opted to voluntarily continue participating in CSAPR trading programs for SO_2 and annual NO_X by adopting the existing CSAPR budgets for those pollutants pursuant to approved SIP revisions.

5. Given the interconnected nature of the trading programs affected by the remand, EPA waited until it had complete information as to how all four states preferred to move forward before starting the rulemaking process for the Proposed Rule.

6. Furthermore, the same staff working on the Proposed Rule also worked on the recently published final CSAPR Update Rule, which addressed good neighbor obligations with respect to the 2008 ozone NAAQS for many states, including Texas, while also addressing the remand of CSAPR Phase 2 ozone season NO_X emission budgets for eleven states, including Texas. This rule was published on October 26, 2016, and substantial EPA resources were needed to develop the final rule and associated technical documents, and to review and respond to significant comments (approximately 15,500 comments were received). *See* 81 Fed. Reg. 74,504 (Oct. 26, 2016). Additionally, through early November 2016, in the fifteen months since the D.C. Circuit issued its decision remanding fifteen CSAPR Phase 2 budgets to EPA on July 28, 2015, EPA has published a final rule addressing the remand as to eleven of the fifteen

remanded budgets, approved a SIP revision from one state resolving the remand as to one of the budgets, obtained commitments from two additional states to submit SIP revisions that (if approved) would resolve the remand as to two of the budgets, and published a proposed rule addressing the remand as to the final budget (the Texas SO_2 budget as it relates to the transport obligation at issue here). Thus, since the CSAPR remand, EPA has been working diligently to respond to the remand.

7. In order to complete action as to the remand of the Texas SO_2 budget, EPA will need to complete a number of procedural steps. In particular, EPA will need to consider and respond to comments received on the Proposed Rule. The Proposed Rule (as it affects Texas) seeks comment on three topics. First, EPA proposes to address the remand of the Texas SO_2 budget by withdrawing the current FIP provisions requiring Texas sources to comply with the remanded budget. 81 Fed. Reg. at 78,958-60. Second, EPA proposes to find that, following withdrawal of those FIP provisions and based on reevaluation of the record for the original CSAPR rulemaking consistent with other holdings in the same D.C. Circuit decision, Texas will no longer have a transport obligation under CAA section 110(a)(2)(D)(i)(I) with regard to the 1997 $PM_{2.5}$ NAAQS, and that EPA consequently will have no obligation or authority to issue new FIP requirements to address such a transport obligation. *Id*. at 78,960. Finally, EPA provides a sensitivity analysis showing that the set of all actions that EPA has taken or expects to take to address the remand of CSAPR Phase 2 budgets, including the withdrawal of the FIP provisions for Texas sources as proposed, would not adversely affect the technical basis for a different EPA rule promulgated in 2012, which allowed states to rely on their participation in CSAPR to satisfy certain regulatory requirements related to regional haze. *Id*. at 78,961-64.

8. EPA anticipates receiving comments on all three aspects of the Proposed Rule. In particular, because the second and third topics are largely technical in nature, it is likely that commenters will choose to submit comments with their own technical analyses supporting or challenging EPA's findings. While EPA cannot anticipate the precise nature of any technical analyses that commenters may submit, EPA believes that, in projecting the most expeditious schedule for completing final action on the Proposed Rule, it is necessary to account for the reasonable possibility that any such technical analyses will be complex and will require EPA to conduct substantial technical review in order to prepare a response.

9. The comment period for the Proposed Rule is currently open and scheduled to close on December 12, 2016. However, EPA has received multiple requests to extend the comment period to 90 days. EPA evaluated those requests and plans to grant an extension of the comment period through January 9, 2017.

10. In addition to responding to comments, EPA must prepare a draft final rule package for management review, including the final rule preamble and any supporting documents for the record that may be necessary to support EPA's final action, such as technical support documents. EPA believes the final rule package may also be subject to interagency review. The determination of whether interagency review is required will be made by officials outside the Agency. If interagency review is required, this review process can only begin once significant work has been completed on the final rule preamble and may take up to three months to complete, during which time EPA can continue appropriate work on the preamble, responses to comments, and any associated technical support documents.

11. Finally, the upcoming change in Administration on January 20, 2017, will likely require additional internal meetings and other steps to brief new agency decision-makers on the

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Proposed Rule, associated legal and technical bases, and any other relevant information (including the CSAPR remand itself) for both informational and decision-making purposes.

Accordingly, EPA has substantial work to do before it can issue a final rule addressing the remand of the Texas Phase 2 SO_2 budget. Based on the time estimated to allow for public comment, respond to comments, prepare a draft final rule, and submit that draft to management and potential interagency review, as well as the transition to a new Administration, EPA believes that October 31, 2017, is the most expeditious date by which EPA can issue a final rule addressing the remand of the Texas Phase 2 SO_2 budget and thereby address any remaining good neighbor obligation for Texas with respect to the 1997 $PM_{2.5}$ NAAQS.

Dated: December 5, 2016

Respectfully submitted,

JOHN C. CRUDEN
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Exhibit C

912 **Federal Register** / Vol. 82, No. 2 / Wednesday, January 4, 2017 / Proposed Rules

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2016–0611; FRL–9955–77-Region 6]

Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or Act), the Environmental Protection Agency (EPA) is proposing to promulgate a Federal Implementation Plan (FIP) in Texas to address the remaining outstanding requirements that are not satisfied by the Texas Regional Haze State Implementation Plan (SIP) submission. Specifically, the EPA proposes SO_2 limits on 29 Electric Generating Units (EGUs) located at 14 Texas facilities to fulfill requirements for the installation and operation of the Best Available Retrofit Technology (BART) for SO_2. To address the requirement for NO_X BART for Texas EGU sources, we are proposing a FIP that relies upon two other EPA rulemakings, one already final and one proposed, which together will establish that participation in the Cross-State Air Pollution Rule (CSAPR) continues to qualify as an alternative to NO_X BART for EGUs in Texas. We also are proposing to disapprove the portion of the Texas Regional Haze SIP that addresses the BART requirement for EGUs for Particulate Matter (PM) and proposing a FIP with PM BART limits for EGUs at 29 EGUs located at 14 Texas facilities, based on existing practices and control capabilities. In addition, we propose to reconsider and re-propose disapproval of portions of several SIP revisions submitted to satisfy the requirement to address interstate visibility transport for six NAAQS and that the FIP emission limits we are proposing meet the interstate visibility transport requirements for these NAAQS.

DATES: *Comments:* Comments must be received on or before March 6, 2017. A public hearing will be held January 10, 2017. For additional logistical information regarding the public hearing please see the **SUPPLEMENTARY INFORMATION** section of this action.

ADDRESSES: Submit your comments, identified by Docket No. EPA–R06–OAR–2016–0611, at *http://www.regulations.gov* or via email to *R6_TX–BART@epa.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov.* The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.* on the web, cloud, or other file sharing system). For additional submission methods, please contact Joe Kordzi, 214–665–7186, *Kordzi.joe@epa.gov.* For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

Docket: The index to the docket for this action is available electronically at *http://www.regulations.gov* and in hard copy at the EPA Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas. While all documents in the docket are listed in the index, some information may be publicly available only at the hard copy location (*e.g.,* copyrighted material), and some may not be publicly available at either location (*e.g.,* CBI).

The Texas regional haze SIP is available online at: *https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html.* It is also available for public inspection during official business hours, by appointment, at the Texas Commission on Environmental Quality, Office of Air Quality, 12124 Park 35 Circle, Austin, Texas 78753.

FOR FURTHER INFORMATION CONTACT: Joe Kordzi, Air Planning Section (6PD–L), Environmental Protection Agency, Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202–2733, telephone 214–665–7186; fax number 214–665–7263; email address *Kordzi.joe@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document wherever ''we,'' ''us,'' or ''our'' is used, we mean the EPA.

Public Hearing: We are holding an information session, for the purpose of providing additional information and informal discussion for our proposal. We are also holding a public hearing to accept oral comments into the record:

Date: Tuesday, January 10, 2017
Time: Open House: 1:30 p.m.–3:30 p.m.
Public hearing: 4:00 p.m.–8:00 p.m. (including short break)
Location: Joe C. Thompson Conference Center (on the University of Texas (UT) Campus), Room 3.102, 2405 Robert Dedman Drive, Austin, Texas 78712

Joe C. Thompson Conference Center parking is adjacent to the building in Lot 40, located at the intersection of East Dean Keeton Street and Red River Street. Additional parking is available at the Manor Garage, located at the intersection of Clyde Littlefield Drive and Robert Dedman Drive. If arranged in advance, the UT Parking Office will allow buses to park along Dedman Drive near the Manor Garage for a fee.

The public hearing will provide interested parties the opportunity to present information and opinions to us concerning our proposal. Interested parties may also submit written comments, as discussed in the proposal. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearing. We will not respond to comments during the public hearing. When we publish our final action, we will provide written responses to all significant oral and written comments received on our proposal. To provide opportunities for questions and discussion, we will hold an information session prior to the public hearing. During the information session, EPA staff will be available to informally answer questions on our proposed action. Any comments made to EPA staff during an information session must still be provided orally during the public hearing, or formally in writing within 30 days after completion of the hearings, in order to be considered in the record.

At the public hearings, the hearing officer may limit the time available for each commenter to address the proposal to three minutes or less if the hearing officer determines it to be appropriate. We will not be providing equipment for commenters to show overhead slides or make computerized slide presentations. Any person may provide written or oral comments and data pertaining to our proposal at the public hearings. Verbatim English language transcripts of the hearing and written statements will be included in the rulemaking docket.

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3. Potential Process for Alternative Scrubber Upgrade Emission Limits
4. SO_2 BART for Gas-fired Units That Burn Oil
5. PM BART
B. Interstate Visibility Transport
VI. Statutory and Executive Order Reviews

I. Background

Regional haze is visibility impairment that is produced by a multitude of sources and activities that are located across a broad geographic area and emit fine particulates ($PM_{2.5}$) (*e.g.,* sulfates, nitrates, Organic Carbon (OC), Elemental Carbon (EC), and soil dust), and their precursors (*e.g.,* Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_X), and in some cases, ammonia (NH_3) and Volatile Organic Compounds (VOCs)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that can be seen. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the ''Interagency Monitoring of Protected Visual Environments'' (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national parks and wilderness areas. In 1999, the average visual range [1] in many Class I areas (*i.e.,* national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States was 100–150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range was less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions.[2] CAA programs have reduced some haze-causing pollution, lessening some visibility impairment and resulting in partially improved average visual ranges.[3]

CAA requirements to address the problem of visibility impairment are continuing to be addressed and implemented. In Section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the prevention of any future, and the remedying of any existing man-made impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I Federal areas.[4] On December 2, 1980, EPA promulgated regulations to address visibility impairment in Class I areas that is ''reasonably attributable'' to a single source or small group of sources, *i.e.,* ''reasonably attributable visibility impairment.'' [5] These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling, and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues, and we promulgated regulations addressing regional haze in 1999.[6] The Regional Haze Rule revised the existing visibility regulations to integrate into the regulations provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in our visibility protection regulations at 40 CFR 51.300–309. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. States were required to submit the first implementation plan addressing regional haze visibility

[1] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.

[2] 64 FR 35715 (July 1, 1999).

[3] An interactive ''story map'' depicting efforts and recent progress by EPA and states to improve visibility at national parks and wilderness areas may be visited at: *http://arcg.is/29tAbS3.*

[4] Areas designated as mandatory Class I Federal areas consist of National Parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to ''mandatory Class I Federal areas.'' Each mandatory Class I Federal area is the responsibility of a ''Federal Land Manager.'' 42 U.S.C. 7602(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

[5] 45 FR 80084 (December 2, 1980).

[6] 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P (Regional Haze Rule).

impairment no later than December 17, 2007.[7]

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often under-controlled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress toward the natural visibility goal, including a requirement that certain categories of existing major stationary sources[8] built between 1962 and 1977 procure, install and operate the ''Best Available Retrofit Technology'' (BART). Larger ''fossil-fuel fired steam electric plants'' are included among the BART source categories. Under the Regional Haze Rule, states are directed to conduct BART determinations for ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. The evaluation of BART for Electric Generating Units (EGUs) that are located at fossil-fuel fired power plants having a generating capacity in excess of 750 megawatts must follow the ''Guidelines for BART Determinations Under the Regional Haze Rule'' at appendix Y to 40 CFR part 51 (hereinafter referred to as the ''BART Guidelines''). Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or alternative program as long as the alternative provides greater reasonable progress towards improving visibility than BART. To the extent a Regional Haze SIP does not meet CAA requirements to address BART, the CAA requires EPA to promulgate a FIP that makes the requisite determinations to ensure the BART requirement is satisfied, as applicable, for sources in the state.[9]

II. Overview of Proposed Actions

A. Regional Haze

On January 5, 2016, we took final action on nearly all portions of a Regional Haze SIP submittal submitted by the State of Texas on March 31, 2009.[10] In that final rule, we did not take action on the portion of the submittal that was intended to satisfy BART requirements for EGUs as mandated by 40 CFR 51.308(e). In an earlier, separate action, we issued a limited disapproval of the Texas Regional Haze SIP concerning EGU BART due to Texas' reliance on the Clean Air Interstate Rule (CAIR).[11] The EGU BART requirements for NO_X and SO_2 remain unmet following the limited disapproval, and Texas has not submitted a revised SIP to address the deficiencies. While we previously proposed to approve the portion of the Regional Haze SIP that was intended to address whether EGUs in Texas must install and operate BART for PM,[12] that part of the proposed action was not finalized.[13] In connection with changed circumstances on how Texas EGUs are able to satisfy NO_X and SO_2 BART, we are now proposing to disapprove the portion of the Texas Regional Haze SIP that evaluated the PM BART requirement for EGUs. The FIP we are proposing today addresses the EGU BART requirement and addresses these deficiencies in the Texas Regional Haze SIP.

Texas' regional haze SIP relied on participation in CAIR as an alternative to meeting the source-specific BART requirements for SO_2 and NO_X. *See* 40 CFR 51.308(e)(4) (2006). At the time that Texas submitted its SIP to EPA, however, the D.C. Circuit had remanded CAIR (without vacatur). *See North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir.), *modified,* 550 F.3d 1176 (D.C. Cir. 2008). The court thereby left CAIR and CAIR FIPs in place in order to ''temporarily preserve the environmental values covered by CAIR'' until we could, by rulemaking, replace CAIR consistent with the court's opinion.[14]

On August 8, 2011, we promulgated the Cross-State Air Pollution Rule (CSAPR), to replace CAIR.[15] In 2012, we issued a limited disapproval of the Texas regional haze SIP because of Texas' reliance on CAIR as an alternative to EGU BART for SO_2 and NO_X.[16] We also determined that CSAPR would provide for greater reasonable progress than BART and amended the Regional Haze Rule to allow CSAPR participation as an alternative to source-specific SO_2 and NO_X BART for EGUs.[17] CSAPR has been subject to extensive litigation, and on July 28, 2015, the D.C. Circuit issued a decision generally upholding CSAPR but remanding without vacating the CSAPR emissions budgets for a number of states in *EME Homer City Generation* v. *EPA,* 795 F.3d 118 (D.C. Cir.). Specifically, the court invalidated a number of the Phase 2 ozone-season NO_X budgets and found that the SO_2 budgets for four states resulted in over-control for purposes of CAA section 110(a)(2)(D)(i)(I). The remand included Texas' ozone-season NO_X budget and annual SO_2 budget.

We had earlier proposed to rely on CSAPR participation to address these BART-related deficiencies in Texas' SIP submittals.[18] Because of the uncertainty caused by the D.C. Circuit Court's partial remand, however, we determined that it was not appropriate to finalize our action. We are in the process of responding to the remand of these CSAPR budgets. On October 26, 2016, we finalized an update to the CSAPR rule that addresses the 1997 ozone NAAQS portion of the remand and the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS.[19] This rule promulgated a new

[7] See 40 CFR 51.308(b). EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).

[8] See 42 U.S.C. 7491(g)(7) (listing the set of ''major stationary sources'' potentially subject-to-BART).

[9] See, 42 U.S.C. 7491(b)(2)(A)(citing the potential need for BART as determined by ''the Administrator in the case of a plan promulgated under section 7410(c) of this title'').

[10] 81 FR 296 (January 5, 2016). A preliminary order of the Fifth Circuit Court of Appeals in Case No. 16–60118 was issued on July 15, 2016, and stayed the rule ''in its entirety.'' On December 2, 2016, the U.S. Department of Justice filed a motion for voluntary remand of the parts of the rule under challenge and consenting to continuation of the judicial stay for remanded parts of the rule. The motion also requested affirmance of the partial approvals of the Texas and Oklahoma SIPs and lifting of the stay as to those approvals. This motion is currently pending disposition.

[11] The limited disapproval triggered the EPA's obligation to issue a FIP for Texas unless the State submitted an approvable SIP revision to correct the relevant deficiencies within 2 years of the final limited disapproval action. CAA section 110(c)(1); 77 FR 33641, 33654 (August 6, 2012).

[12] 79 FR 74817, 74851 (proposing to concur with screening analyses conducted by TCEQ including findings that no Texas EGUs are subject to BART for PM).

[13] 81 FR at 302 (January 5, 2016): ''[W]e proposed to approve Texas' determination that for its EGUs no PM BART controls were appropriate, based on a screening analysis of the visibility impacts of from just PM emissions. . . ..we have. . . .decided not to finalize our proposed approval of Texas' PM BART determination [for EGUs].''

[14] 550 F.3d at 1178.

[15] 76 FR 48208.

[16] 77 FR 33641.

[17] While that rulemaking also promulgated FIPs for several states to replace reliance on CAIR with reliance on CSAPR as an alternative to BART, it did not include a FIP for Texas. 77 FR 33641, 33654.

[18] 79 FR 74817, 74823 (December 16, 2014).

[19] ''Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS.'' 81 FR74504. The relevant portion of the remand pertained to the Phase 2 ozone season NO_X emission budget designed to address the 1997 ozone NAAQS. In response to the remand, in this final rule the EPA removed the regulatory requirement for sources in Texas to comply with the phase 2 ozone season NO_X budget calculated to address the 1997 ozone standard because we determined that no additional emission reductions from sources in Texas are necessary to address the State's obligation under 110(a)(2)(D)(i)(I) for the 1997 ozone NAAQS. However, because Texas is linked to downwind air quality problems with respect to the 2008 ozone NAAQS, we promulgated a new ozone season NO_X emission budget to address that standard. 81 FR 74504, 74600–74601.

FIP for Texas that replaced the CSAPR ozone season NO_X emission budget designed to address the 1997 ozone NAAQS for the State with a revised budget designed to address the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS. Then, on November 10, 2016, we proposed to withdraw the FIP provisions that require affected EGUs in Texas to participate in CSAPR for annual emissions of SO_2 and NO_X with regard to emissions after 2016.[20] Withdrawal of these FIP requirements will address the D.C. Circuit's remand of the CSAPR Phase 2 SO_2 budget for Texas. This recently published proposed rule includes an assessment of the impacts of the set of actions that the EPA has taken or expects to take in response to the D.C. Circuit's remand on our 2012 demonstration that participation in CSAPR would provide for greater reasonable progress than BART.

In 2012, we determined that CSAPR is ''better-than-BART'' based on a comparison of projected visibility in scenarios representing CSAPR implementation and BART implementation, as well as a base case without CSAPR or BART, in relevant locations throughout the country. In the case of the remanded Phase 2 ozone-season NO_X budgets, eight of the states with remanded budgets (including Texas) will continue to be subject to CSAPR to address ozone transport obligations with regard to the more stringent 2008 ozone NAAQS, and North Carolina and South Carolina, although no longer covered by CSAPR to address ozone transport obligations, will continue to be subject to CSAPR annual NO_X requirements in order to address their $PM_{2.5}$ transport obligations. In considering the potential impact of the remand of Phase 2 budgets on the 2012 CSAPR-Better-than-BART analytic demonstration, we therefore believe that only two changes have potential relevance: The withdrawal of the FIP provisions subjecting Florida EGUs to CSAPR ozone-season NO_X requirements that has already been finalized, and the withdrawal of FIP provisions subjecting Texas EGUs to CSAPR SO_2 and annual NO_X requirements that is proposed separately. That proposed analysis supports the continued conclusion that CSAPR participation would achieve greater reasonable progress than BART for NO_X despite the change in the treatment of Texas and Florida EGUs. Consequently, we have proposed that the Regional Haze Rule continues to authorize the use of CSAPR participation as a BART alternative for EGUs.[21] Finalization of that proposal would allow for Texas' regional haze program to rely on CSAPR ozone season control program participation as an alternative to source-specific EGU BART for NO_X.[22] Based on that national proposal, we are now proposing a FIP to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. Finalization of this portion of the FIP is contingent on our taking final action to find that CSAPR continues to be an appropriate alternative to source specific BART. However, finalization of the portion of our national proposal that would withdraw the FIP provisions for Texas for annual emissions of SO_2 and NO_X described above would mean that Texas will no longer be eligible to rely on CSAPR participation as an alternative to source-specific EGU BART for SO_2. As a result, we are proposing to promulgate a FIP that includes BART screening of sources and a source-by-source analysis for SO_2 BART and controls for this pollutant as appropriate. We are also unable to propose approval of the Texas Regional Haze SIP's PM BART evaluation, as previously proposed, as that demonstration made underlying assumptions that are no longer valid.[23] We instead propose to disapprove that portion of the SIP and, in place of it, promulgate source-specific PM BART requirements for EGUs that we have evaluated to be subject to BART in this proposed FIP.

We believe, however, it is preferable for states to assume primary responsibility for implementing the Regional Haze requirements as envisioned by the CAA. We will work with the State of Texas if it chooses to develop a SIP to meet these overdue Regional Haze requirements and replace or avoid a finalized FIP.

The FIP we are proposing includes BART control determinations for EGUs in Texas without previously approved BART determinations and associated compliance schedules and requirements for equipment maintenance, monitoring, testing, recordkeeping, and reporting for all affected sources and units. The EGU BART sources addressed in this FIP cause or contribute to visibility impairment at one or more Class I areas in Texas, Oklahoma, Arkansas, and New Mexico. The two Class I areas in Texas are Big Bend National Park and the Guadalupe Mountains National Park. The Class I area in Oklahoma is the Wichita Mountains National Wildlife Refuge. The two Class I areas in Arkansas are the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area. The closest impacted Class I areas in New Mexico are the Carlsbad Caverns National Park, Salt Creek Wilderness Area, and White Mountains Wilderness Area.

In order to remedy these deficiencies in the Texas SIP, we are proposing this FIP to establish the means by which the regional haze program for Texas will meet the BART requirements for SO_2, NO_X, and PM. We are proposing source-specific BART determinations for EGUs subject to BART for SO_2 and PM. We are proposing that NO_X BART requirements for EGUs in Texas will be satisfied by a determination, proposed for separate finalization, that Texas' participation in CSAPR's ozone season control program is a permissible alternative to source-specific NO_X BART.

Addressing the BART requirement for Texas EGUs, as proposed today, with cost-effective and readily available controls, will help ensure that progress

[20] ''Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas,'' 81 FR 78954 (November 10, 2016). Although the court's decision specifically remanded only Texas' SO_2 budget, the court's rationale for remanding that budget also implicates Texas' annual NO_X budget because the SO_2 and annual NO_X budgets were developed through an integrated analysis and were promulgated to meet a common $PM_{2.5}$ transport obligation under CAA section 110(a)(2)(D)(i)(I).

[21] 81 FR at 78962–78964.

[22] While we have proposed to remove Texas from CSAPR's annual NO_X program, CSAPR is still an appropriate alternative to BART for NO_X purposes because EGUs in Texas continue to be required to participate in CSAPR's ozone season NO_X program.

[23] We previously proposed approval of Texas' SIP for EGU PM BART on the premise that EGU BART for both SO_2 and NO_X were covered by participation in CSAPR, which allowed Texas to conduct a screening analysis of the visibility impacts from PM emissions in isolation. However, modeling on a pollutant-specific basis for PM is appropriate only in the narrow circumstance where a state relies on a BART alternative to satisfy NO_X and SO_2 BART. Due to the complexity and nonlinear nature of atmospheric chemistry and chemical transformation among pollutants, EPA has not recommended performing modeling on a pollutant-specific basis to determine whether a source is subject to BART, except in the unique situation described above. See discussion in Memorandum from Joseph Paisie to Kay Prince, ''Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations,'' July 19, 2006. More recently, the Ninth Circuit upheld EPA's disapproval of the Arizona regional haze SIP for including a pollutant-specific screening analysis for NO_X. *Phoenix Cement Co.* v. *EPA,* 647 F. App'x 702, 705–06 (9th Cir. Mar. 31, 2016) (upholding EPA's interpretation that the ''Regional Haze Rule [] require[s] a BART determination for any pollutant at a source that exceeds the de minimis threshold, once that source has been determined subject to BART.''). We did not finalize our proposed approval of Texas' EGU PM BART determination because of the uncertainty at that time concerning the CSAPR remand and whether Texas would continue to have CSAPR coverage for both NO_X and SO_2, 81 FR 296, 302, but that uncertainty has now been resolved.

is made toward natural visibility conditions at Class I areas affected by Texas' sources. Please refer to our previous rulemaking on the Texas regional haze SIP for additional background regarding the CAA, regional haze, and our Regional Haze Rule.[24]

B. Interstate Transport of Pollutants That Affect Visibility

Section 110(a) of the CAA directs states to submit a SIP that provides for the implementation, maintenance, and enforcement of each NAAQS, which is commonly referred to as an infrastructure SIP. Among other things, CAA 110(a)(2)(D)(i)(II) requires that SIPs contain adequate provisions to prohibit interference with measures required to protect visibility in other states. This requirement is referred to as ''interstate visibility transport.'' SIPs addressing interstate visibility transport are due to EPA within three years after the promulgation of a new or revised NAAQS (or within such shorter period as we may prescribe). A state's failure to submit a complete, approvable SIP for interstate visibility transport creates an obligation for EPA to promulgate a FIP to address this requirement.[25]

Previously, we issued a finding that Texas failed to submit a SIP revision to satisfy all four requirements of interstate transport under section 110(a)(2)(D)(i) of the CAA for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.[26] Texas later submitted a SIP revision to address interstate transport for these NAAQS. However, in our January 5, 2016 final action we disapproved the portion of Texas' SIP revisions intended to address interstate visibility transport for six NAAQS, including the 1997 8-hour ozone and 1997 $PM_{2.5}$.[27] We concluded that to meet the requirements of interstate visibility transport: (1) Texas could not rely on its Regional Haze SIP, which relied heavily upon the remanded CAIR, to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states; and (2) additional control of SO_2 emissions in Texas were needed to prevent interference with measures required to be included in the Oklahoma SIP to protect visibility. However, in that action we did not finalize the portion of our proposed FIP addressing Texas' interstate visibility transport obligations because that portion of the proposed FIP would have partially relied on CSAPR to ensure the emissions from Texas' sources do not interfere with other states' visibility programs. Given the uncertainty that existed at the time arising from the D.C. Circuit's remand of Texas' CSAPR budgets (*EME Homer City Generation* v. *EPA,* 79 F.3d 118 (D.C. Cir.)), we concluded that it was not appropriate to finalize our proposed determination to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas in that action.[28]

Our prior disapproval of interstate visibility transport for the six NAAQS is currently stayed by the Fifth Circuit.[29] We recognize that because our prior disapproval of the Texas SIP submittals addressing interstate visibility transport relied in part on our determinations of the measures needed in Texas to ensure reasonable progress in Oklahoma, the Fifth Circuit's stay of our previous action complicates next steps to ensure that the visibility requirements of CAA 110(a)(2)(D)(i)(II) are met. The Court's stay accordingly calls into question whether our past disapprovals for interstate visibility transport would stand. At the same time, we also note that we continue to have an obligation to issue a FIP for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS as a result of our 2005 finding that Texas failed to timely submit SIPs to address the interstate transport visibility requirements. Given the uncertainties arising from the Fifth Circuit's stay of our prior disapproval, we are now proposing to reconsider the basis of our prior disapproval of Texas' SIP submittals addressing the interstate visibility transport requirement for all six NAAQS. We are now proposing to determine that Texas' SIP submittals addressing interstate visibility transport for the six NAAQS are not approvable because these submittals relied solely on Texas' Regional Haze SIP to ensure that emissions from Texas did not interfere with required measures in other states. Texas' Regional Haze SIP, in turn, relied on the implementation of CAIR as an alternative to EGU BART for SO_2 and NO_X. Specifically, we are proposing disapproval of the following Texas SIP submittals insofar as they address the interstate visibility transport requirement: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). Texas has not submitted a SIP revision to remove reliance on CAIR for Regional Haze or interstate visibility transport. As CAIR is no longer in effect and has been replaced by CSAPR, we are proposing to find that Texas' Regional Haze SIP does meet its interstate visibility transport obligations. As a result, the Texas SIPs to address interstate visibility transport for these six NAAQS continue to be unapprovable.

We are proposing a FIP to cure the deficiencies in Texas' Regional Haze Program concerning EGU BART. This FIP will replace reliance on CAIR with reliance on CSAPR to meet the requirements for EGU BART for NO_X in Texas. The FIP will also address Texas EGU BART for SO_2 and PM on a source-specific basis. With the absence of CSAPR coverage for SO_2, we must reevaluate what is needed in Texas to address interstate visibility transport. Our proposed FIP to address Texas EGU BART achieves significant reductions of SO_2, which exceed the reductions initially assumed for Texas under either CAIR or CSAPR. In addition, our proposed FIP achieves reductions at large sources of SO_2 emissions (*e.g.,* Monticello, Martin Lake and Big Brown), that have significant impacts on

[24] 81 FR 296. The public docket for this past rulemaking remains accessible under EPA Docket ID: EPA–R06–OAR–2014–0754 at *https://www.regulations.gov.* This proposed rulemaking has a separately established docket (EPA–R06–OAR–2016–0611). Our TSD contains a list of materials from EPA Docket ID: EPA–R06–OAR–2014–0754 that we incorporate by reference and consider to be part of this rulemaking record even as they are not necessarily re-uploaded to the newer docket.

[25] CAA § 110(c)(1). Mandatory sanctions under CAA section 179 do not apply because the deficiencies are not with respect to a submission that is required under CAA title I part D. ''Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and (2)'' at pages 34–35 (September 13, 2013) [hereinafter 2013 i-SIP Guidance].

[26] 70 FR 21147 (April 25, 2005). The four components of interstate transport in Section 110(a)(2)(D)(i) are contained in two subsections. Section 110(a)(2)(D)(i)(I) addresses any emissions activity in one state that contributes significantly to nonattainment, or interferes with maintenance, of the NAAQS in another state. Section 110(a)(2)(D)(i)(II) requires SIPs to include provisions prohibiting any source or other type of emissions activity in one state from interfering with measures required of any other state to prevent significant deterioration of air quality or from interfering with measures required of any other state to protect visibility (referring to visibility in Class I areas). This proposal only addresses the fourth requirement concerning visibility.

[27] Specifically, we previously disapproved the relevant portion of these Texas' SIP submittals: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). 79 FR 74818, 74821; 81 FR 296, at 302.

[28] 81 FR 296, 301–2.

[29] July 15, 2016 Order in *Texas* v. *EPA* (Fifth Cir. Case No. 16–160118). The EPA's filed motion requesting voluntary partial remand and continuation of the judicial stay for remanded parts of the rule includes our prior disapproval of Texas' SIPs concerning interstate visibility transport. This motion is currently pending disposition.

Class I areas in nearby states. The BART FIP requires controls on many but not all of the sources that were controlled in our previous partial FIP for Texas Regional Haze. The EGU BART FIP also includes control requirements at some additional sources not controlled in our previous action on Texas Regional Haze.

We are proposing to find that our proposed EGU BART FIP is adequate to prevent interference with measures required to protect visibility in other states for the first planning period.[30] We, therefore, propose that the measures in our proposed FIP to address Texas EGU BART will fully address Texas' interstate visibility transport obligations for the six NAAQS (1997 8-hour ozone, 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 2008 8-hour ozone, 2010 1-hour NO_2, and 2010 1-hour SO_2). We also propose that reliance on CSAPR for EGU NO_X BART is appropriate to ensure NO_X emissions from Texas EGUs do not interfere with other states' measures to protect visibility. We are proposing this action based on the reasoning that our BART FIP will achieve more emission reductions than projected under CAIR or CSAPR and the reductions are occurring at sources that have particularly large impacts on Class I areas outside of Texas. To the extent our previous final action concerning Texas Regional Haze is remanded by a Court or otherwise reconsidered in the future, we may revisit whether controls in the EGU BART FIP are adequate to address interstate visibility transport requirements. Nonetheless, we are here proposing that the proposed EGU BART FIP measures will be adequate to address interstate visibility transport based on current information. This proposal concerning the adequacy of the proposed FIP remedy does not depend on our earlier action on the Texas Regional Haze SIP or hinge on its disposition, nor does it foreclose that we may reexamine visibility transport concerns under potential scenarios where we have a responsibility to take new action.[31]

We encourage Texas to consider adopting additional SIP provisions that would allow the EPA to fully approve the Regional Haze SIP and thus to withdraw the FIP and approve Texas' SIP with respect to interstate visibility transport. Texas may also elect to satisfy interstate visibility transport by providing, as an alternative to relying on its Regional Haze SIP alone, a demonstration that emissions within its jurisdiction do not interfere with other states' plans to protect visibility.[32]

C. Our Obligation To Promulgate a FIP

Under section 110(c) of the CAA, whenever we disapprove a mandatory SIP submission in whole or in part, we are required to promulgate a FIP within 2 years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. Specifically, CAA section 110(c) provides that the Administrator shall promulgate a FIP within 2 years after the Administrator disapproves a state implementation plan submission ''unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.''[33] The term ''Federal implementation plan'' is defined in Section 302(y) of the CAA in pertinent part as a plan promulgated by the Administrator to correct an inadequacy in a SIP.

Beginning in 2012, following the limited disapproval of the Texas Regional Haze SIP, EPA had the authority and obligation to promulgate a FIP to address BART for Texas EGUs for NO_X and SO_2. In proposing to disapprove the Regional Haze SIP component that sought to address the PM BART requirement for Texas EGUs, we also have the obligation to promulgate a PM BART FIP to address the deficiency. Texas has not addressed the EGU BART disapproval, and that requirement is now significantly overdue.[34] We are accordingly empowered and required by the CAA to make determinations and promulgate a FIP to ensure the BART requirement for Texas EGUs is satisfied.

Adding to this background, beginning with our January 5, 2016 disapproval of Texas SIP provisions regarding interstate visibility transport, we obtained the authority and obligation to promulgate a FIP to correct the deficiencies relating to that CAA requirement.[35] As with the BART requirement, we lack a SIP revision that would have any potential to correct the deficiency, necessitating that we now take action under FIP authority.

III. Our Proposed BART Analyses for SO_2 and PM

In our previous action,[36] we determined that due to the CSAPR remand, it was not appropriate at that time to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas. As a consequence, action to satisfy the overdue requirement to address BART for EGUs in the state of Texas was further delayed.[37] In this proposal, we are proposing that CSAPR, once fully revised to address the D.C. Circuit's remand, provides a basis for satisfying EGU BART obligations for NO_X alone. It remains the case that we cannot rely on CSAPR as an alternative to SO_2 BART for Texas EGUs as further confirmed by our proposed action to remove Texas from the annual NO_X and SO_2 control programs. Thus, we have the obligation to consider source-specific requirements for Texas EGUs consistent with the BART Guidelines for SO_2 BART.

Because the component of the Texas Regional Haze SIP regarding the PM BART requirement for EGUs has not been acted on, we have the responsibility under CAA section 110(k) to evaluate the submission and take action to approve or disapprove it. The SIP determinations for PM were based on modeling that was conducted by examining visibility impairment due to PM emissions alone, based on the assumption that the state would be participating in CAIR for SO_2 and NO_X and thereby having BART coverage for those pollutants. The Texas Regional Haze SIP had concluded that no PM BART controls for EGUs were appropriate, because modeling assessment of PM impacts alone showed their impacts to be too small to warrant control consideration. But Texas' screening analysis is no longer reliable or accurate because of the invalid assumption that source-by-source BART for either SO_2 or NO_X would not be

[30] This proposed FIP for interstate visibility transport is premised on the interpretation that this requirement can be addressed even when a Regional Haze SIP is not fully approved and the FIP does not purport to correct all Regional Haze SIP deficiencies. *See e.g.* 76 FR 52388 (August 22, 2011); 76 FR 22036 (April 20, 2011); and 78 FR 14681 (March 7, 2013); *see also*, 2013 i-SIP Guidance, at page 34 (stating that EPA may find it appropriate to supplement the i-SIP Guidance regarding the relationship between Regional Haze SIPs and interstate visibility transport for future planning periods).

[31] *See e.g.* 78 FR 14681, 14685.

[32] 2013 i-SIP Guidance, at pages 34–35.

[33] EPA additionally has the authority to promulgate a FIP any time after finding that ''a State has failed to make a required submission'' of a SIP. CAA section 110(c)(1)(A); 42 U.S.C. 7410(c)(1)(a).

[34] The Texas Regional Haze SIP stated, ''The TCEQ will take appropriate action if CAIR is not replaced with a system that the US EPA considers to be equivalent to BART.'' BART determinations were due in SIP submissions on December 17, 2007, 40 CFR 51.308(b), putting them on a timeline for controls by 2014 (considering the deadline for SIP action at CAA section 110(k)(2) and allowing five years for installation of BART controls). Additional delay of any amount is not appropriate and not consistent with the law.

[35] Additionally, we continue to have authority to issue a FIP to address interstate visibility transport for 1997 8-hour ozone and 1997 $PM_{2.5}$ due to our 2005 finding that Texas failed to submit SIPs to address interstate transport for these NAAQS under CAA section 110(a)(2)(D)(i). 70 FR 21147.

[36] See the discussion beginning on 81 FR 301 (January 5, 2016).

[37] Id. at 346.

required. In order to appropriately evaluate the BART requirements for EGUs, the visibility impacts from all pollutants must be studied, including PM emissions. Texas' PM BART analysis for EGUs does not do this.[38]

Accordingly, we are proposing to disapprove the portion of the Texas Regional Haze SIP that determined that all Texas EGUs screen out of the BART requirement for PM. The basis for the proposed disapproval is the SIP determination's assumption that EGUs would have coverage for SO_2 and NO_X BART under an alternative measure.[39] Since that assumption is not valid, the technical determinations regarding PM BART cannot be approved. Following the directions of the BART Guidelines on how to identify sources ''subject to BART,'' we have looked at all visibility impairing pollutants from EGUs that are BART-eligible. Our proposed FIP therefore seeks to fill that regulatory gap by assessing BART for Texas EGUs for visibility impairing pollutants other than NO_X, *i.e.,* SO_2 and PM.

A. Identification of BART-Eligible Sources

The BART Guidelines set forth the steps for identifying whether the source is a BART-eligible source: [40]

Step 1: Identify the emission units in the BART categories,

Step 2: Identify the start-up dates of those emission units, and

Step 3: Compare the potential emissions to the 250 ton/yr cutoff.

Following our 2016 final action on the March 31, 2009 Texas RH SIP, we began the process of generating additional technical information and analysis in order to address the above three steps in our BART-eligibility proposal. We started with Texas' facility-specific listing of BART-eligible EGU sources and removed sources we verified had retired. We then gathered additional information from (1) our authority under Section 114(a) of the CAA to request information from potential BART-eligible sources, and (2) the U.S. Energy Information Administration (EIA). We then converted Texas' facility-specific BART-eligible list to a unit-specific BART-eligible list and verified the BART-eligibility of each unit. The following is a list of units we propose have satisfied the above three steps and are BART-eligible: [41]

TABLE 1—SUMMARY OF BART-ELIGIBILITY ANALYSIS

Facility	Unit
Barney M. Davis (Talen/Topaz)	1.
Big Brown (Luminant)	1.
Big Brown (Luminant)	2.
Cedar Bayou (NRG)	CBY1.
Cedar Bayou (NRG)	CBY2.
Coleto Creek (Engie)	1.
Dansby (City of Bryan)	1.
Decker Creek (Austin Energy)	1.
Decker Creek (Austin Energy)	2.
Fayette (LCRA)	1.
Fayette (LCRA)	2.
Graham (Luminant)	2.
Greens Bayou (NRG)	5.
Handley (Exelon)	3.
Handley (Exelon)	4.
Handley (Exelon)	5.
Harrington Station (Xcel)	061B.
Harrington Station (Xcel)	062B.
J T Deely (CPS Energy)	1.
J T Deely (CPS Energy)	2.
Jones Station (Xcel)	151B.
Jones Station (Xcel)	152B.
Knox Lee Power Plant (AEP)	5.
Lake Hubbard (Luminant)	1.
Lake Hubbard (Luminant)	2.
Lewis Creek (Entergy)	1.
Lewis Creek (Entergy)	2.
Martin Lake (Luminant)	1.
Martin Lake (Luminant)	2.
Martin Lake (Luminant)	3.
Monticello (Luminant)	1.
Monticello (Luminant)	2.
Monticello (Luminant)	3.
Newman (El Paso Electric)	2.
Newman (El Paso Electric)	3.
Newman (El Paso Electric)	4.
Nichols Station (Xcel)	143B.
O W Sommers (CPS Energy)	1.
O W Sommers (CPS Energy)	2.
Plant X (Xcel)	4.
Powerlane (City of Greenville)	ST1.
Powerlane (City of Greenville)	ST2.
Powerlane (City of Greenville)	ST3.
R W Miller (Brazos Elec. Coop)	1.
R W Miller (Brazos Elec. Coop)	2.
R W Miller (Brazos Elec. Coop)	3.
Sabine (Entergy)	2.
Sabine (Entergy)	3.
Sabine (Entergy)	4.
Sabine (Entergy)	5.
Sim Gideon (LCRA)	1.
Sim Gideon (LCRA)	2.
Sim Gideon (LCRA)	3.
Spencer (City of Garland)	4.
Spencer (City of Garland)	5.
Stryker Creek (Luminant)	ST2.
Trinidad (Luminant)	6.
Ty Cooke (City of Lubbock)	1.
Ty Cooke (City of Lubbock)	2.
V H Braunig (CPS Energy)	1.
V H Braunig (CPS Energy)	2.
V H Braunig (CPS Energy)	3.
W A Parish (NRG)	WAP4.
W A Parish (NRG)	WAP5.
W A Parish (NRG)	WAP6.
Welsh Power Plant (AEP)	1.
Welsh Power Plant (AEP)	2.
Wilkes Power Plant (AEP)	1.
Wilkes Power Plant (AEP)	2.
Wilkes Power Plant (AEP)	3.

The final step in identifying a ''BART-eligible source'' is to use the information from the previous three steps to identify the collection of emissions units that comprise the BART-eligible source.

B. Identification of Sources That Are Subject to BART

Following our compilation of the BART-eligible sources in Texas, we examined whether these sources cause or contribute to visibility impairment in nearby Class I areas.[42] For those sources that are not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area, a BART determination is not required. Those sources are determined to be not subject-to-BART. Sources that are reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are determined to be subject-to-BART. For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that states (or EPA, in the case of a FIP) identify the level of control representing BART after considering the factors set out in CAA section 169A(g). The BART guidelines discuss several approaches available to exempt sources from the BART determination process, including modeling individual sources and the use of model plants. To determine which sources are anticipated to contribute to visibility impairment the BART guidelines state that CALPUFF or another appropriate model can be used to predict the visibility impacts from a single source at a Class I area. We employed a four-fold strategy in determining which units should or should not be subject to BART. A flowchart of the analysis along with a detailed discussion of the subject-to-BART screening analysis is provided in

[38] Texas' Regional Haze SIP determined whether its sources should be subject to review for PM controls by only looking at the impact of PM emissions on visibility. This approach is only appropriate when a state satisfies the requirements for BART for SO_2 and NO_X with an alternative measure. Additionally, as reflected in our TSD on the identification of BART-Eligible Sources, the Texas SIP neglected to identify several BART-eligible sources; this also shows error in the state's PM BART demonstration and conclusions, and it constitutes grounds for the proposed partial SIP disapproval for PM BART.

[39] The requirements for ''emissions trading programs or other alternative measures'' that may be implemented rather than requiring BART are provided at 40 CFR 51.308(e)(2).

[40] 70 FR 39158 (July 6, 2005).

[41] See our BART FIP TSD for more information concerning how we selected the units we are proposing are BART-eligible and other details concerning our proposed BART determinations.

[42] See 40 CFR part 51, Appendix Y, III, How to Identify Sources ''Subject to BART''.

the BART Screening TSD.[43] We summarize the methodology and results of this analysis here.

First, we examined whether any of the BART-eligible units should be eliminated from consideration based on the standard model plant exemptions described in the BART Guidelines.[44] Second, we created specific model plants between sources and nearby Class I areas and conducted CALPUFF modeling to evaluate a number of sources for exemption. Third, we performed stand-alone, source specific CALPUFF modeling on a number of units to determine if their visibility impacts were large enough to identify them as being subject to BART. Fourth, for those remaining units outside of the CALPUFF model's range, we contracted to have CAMx modeling performed to determine if their visibility impacts were large enough to merit their being subject to BART. These steps are further described below.

For states using modeling to determine the applicability of BART to single sources, the BART Guidelines note that the first step is to set a contribution threshold to assess whether the impact of a single source is sufficient to cause or contribute to visibility impairment at a Class I area. The BART Guidelines preamble advises that, ''for purposes of determining which sources are subject to BART, States should consider a 1.0 deciview change or more from an individual source to ''cause'' visibility impairment, and a change of 0.5 deciviews to ''contribute'' to impairment.'' [45] It further advises that ''States should have discretion to set an appropriate threshold depending on the facts of the situation,'' but ''[a]s a general matter, any threshold that you use for determining whether a source 'contributes' to visibility impairment should not be higher than 0.5 dv,'' and describes situations in which states may wish to exercise their discretion to set lower thresholds, mainly in situations in which a large number of BART-eligible sources within the State and in proximity to a Class I area justify this approach. We do not believe that the sources under consideration in this rule, most of which are not in close proximity to a Class I area, merit the consideration of a lesser contribution threshold. Therefore, our analysis employs a contribution threshold of 0.5 deciviews.

1. Our Use of the Standard BART Model Plant Exemption

As the BART Guidelines note:

> [W]e believe that a State that has established 0.5 deciviews as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tons per year of NO_X or SO_2 (or combined NO_X and SO_2), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tons per year of NO_X or SO_2 (or combined NO_X and SO_2) that are located more than 100 kilometers from any Class I area. You do, however, have the option of showing other thresholds might also be appropriate given your specific circumstances.[46]

We applied the standard BART model plant exemption described above to the following facilities, exempting them from further analysis:

TABLE 2—STANDARD BART MODEL PLANT EXEMPT SOURCES

Facility	Units
Dansby (City of Bryan)	1.
Greens Bayou (NRG)	5.
Nichols Station (Xcel)	143B.
Plant X (Xcel)	4.
Powerlane (City of Greenville).	ST1, ST2 & ST3.
Spencer (City of Garland)	4 & 5.
Trinidad (Luminant)	6.
Ty Cooke (City of Lubbock)	1 & 2.

2. Our Extension of the BART Model Plant Exemption

As the BART Guidelines note, the standard BART model plant exemption can be extended to values other than the 500 tons/50 km and 1,000 tons/100 km scenarios discussed in the previous section. The BART Guidelines explain that: ''you may find based on representative plant analyses that certain types of sources are not reasonably anticipated to cause or contribute to visibility impairment. To do this, you may conduct your own modeling to establish emission levels and distances from Class I areas on which you can rely to exempt sources with those characteristics.'' [47]

Modeling analyses of representative plants are used to reflect groupings of specific sources with important common characteristics. We conducted CALPUFF modeling to establish emission levels and distances from Class I areas on which we could rely to exempt sources with those characteristics. In this approach, a hypothetical facility (''model plant'') is located between a group of BART-eligible sources and a Class I area. Predominant wind patterns and elevation are considered in locating the model plant such that conditions that would be anticipated to transport pollution from the group of BART-eligible sources to the Class I area are consistent with conditions anticipated to transport pollution from the model plant to the Class I area. The visibility impacts from this model plant are modeled utilizing CALPUFF following the protocol described in the BART Screening TSD. Model plant emissions are adjusted such that the modeled visibility impact (maximum of 98th percentile values for 2001, 2002, and 2003) is below the screening threshold of 0.5 dv. For each model plant, the Q/d value is calculated as the annual emissions (combined NO_X and SO_2 emissions) divided by distance to the Class I area (km) resulting in a critical Q/d value. The Q/d value for each BART-eligible source is calculated based on annual emissions based on the maximum actual 24-hr emission rate and distance to the Class I area and is then compared to the critical Q/d value. For a BART-eligible source with a lower Q/d value than the critical Q/d, it is reasonably anticipated that the visibility impact from the BART-eligible source is lower than the model plant and therefore below the screening threshold and not subject to BART. See the BART Screening TSD for additional discussion and source-specific information used in this model plant screening analysis. By this extension of the BART model plant exemption, we identified the following additional facilities that can be exempted from further analysis:

TABLE 3—EXTENDED BART MODEL PLANT EXEMPT SOURCES

Facility	Units
Barney M. Davis (Talen/Topaz).	1.
Cedar Bayou (NRG)	CBY1 & CBY2.
Decker Creek (Austin Energy)	1 & 2.
Lewis Creek (Entergy)	1 & 2.
Sabine (Entergy)	2, 3, 4 & 5.
Sim Gideon (LCRA)	1, 2 & 3.
V H Braunig (CPS Energy)	1, 2 & 3.

3. Our Use of CALPUFF Modeling To Exempt Sources From Being Subject to BART

Those sources that did not screen out using the model plant approach were modeled directly with CALPUFF if they were in a range of when CALPUFF has

[43] See our TSD, ''Our Strategy for Assessing which Units are Subject to BART for the Texas Regional Haze BART Federal Implementation Plan (BART Screening TSD)'' in our docket.

[44] See the discussion beginning on 70 FR 39104, 39162 (July 6, 2005) [40 CFR part 51, App. Y].

[45] 70 FR at 39118.

[46] 70 FR at 39163 [40 CFR part 51, App. Y].

[47] 70 FR at 39163 [40 CFR part 51, App. Y].

been previously used. Historically CALPUFF has been used at distances up to approximately 400 km. The maximum 98th percentile impact from the modeled years (calculated based on annual average natural background conditions) was compared with the 0.5 dv screening threshold following the modeling protocol described in the BART screening TSD. The BART Guidelines recommend that states use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods of start-up, shutdown, or malfunction. The maximum 24-hour emission rate (lb/hr) for NO_X and SO_2 from the 2000–2004 baseline period for each source was identified through a review of the daily emission data for each BART-eligible unit from EPA's Air Markets Program Data.[48] For some BART-eligible sources, evaluation of baseline emissions revealed evidence of the installation of NO_X control technology during the baseline period. For those sources, the maximum emission rate was updated to reflect the identified maximum emission rate from the post-control portion of the baseline period. Because daily emissions are not available for PM, the annual average emission rate was doubled to approximate the 24-hr maximum emission rate for PM. See the BART Screening TSD for additional discussion and source-specific information used in the CALPUFF modeling for this portion of the screening analysis. With the use of CALPUFF modeling results, we identified the following additional facilities that can be exempted from further analysis:

TABLE 4—CALPUFF BART EXEMPT SOURCES

Facility	Units
Handley (Exelon)	3, 4 & 5.
Jones (Xcel)	151B & 152B.
Lake Hubbard (Luminant)	1 & 2.
Knox Lee (AEP)	5.
R W Miller (Brazos Elec. Coop).	1, 2 & 3.

Based on these CALPUFF screening analyses using model plant approaches and direct modeling, the following gas[49]/fuel oil fired facilities did not screen out from being subject to BART: Newman, Stryker, Graham, and Wilkes. None of the coal fired facilities screened out in our CALPUFF modeling for the facilities within CALPUFF range.

4. Our Use of CAMx Modeling To Exempt Sources From Being Subject to BART

Some of the BART-eligible sources in Texas are geographically distant from a Class I area, yet have high enough emissions that they may significantly impact visibility at Class I areas in Texas and surrounding states. However, the use of CALPUFF is not recommended for distances much greater than 300 km, and has typically not been used at distances more than approximately 400 km. To determine which sources are anticipated to contribute to visibility impairment the BART guidelines state that CALPUFF or another appropriate model can be used to predict the visibility impacts from a single source at a Class I area. CAMx provides a scientifically defensible platform for assessment of visibility impacts over a wide range of source-to-receptor distances. CAMx is also more suited than some other modeling approaches for evaluating the impacts of SO_2, NO_X, VOC and PM emissions as it has a more robust chemistry mechanism. The CAMx PM Source Apportionment Technology (PSAT) modeling was conducted for those BART-eligible sources that have large SO_2 emissions.[50] In 2006/2007, the TCEQ developed a modeling protocol and analysis using CAMx with the same Plume in Grid and PSAT techniques to evaluate visibility impacts from non-EGU BART sources, as well as to evaluate VOC and PM impacts from all BART-eligible sources to inform the 2009 Texas Regional Haze SIP.[51] [52] This modeling protocol was reviewed by the TCEQ, EPA and FLM representatives specialized in air quality analyses and BART prior to performing the analysis and submission of their regional haze SIP. Our subject-to-BART screening modeling for EGU-sources using CAMx is consistent with the protocol developed and utilized by Texas in their regional haze SIP. We are using more recent model versions with updated science in our analysis.

Consistent with the BART guidelines and our CALPUFF modeling, for the selected BART-eligible sources we used the maximum actual 24-hr emission rates for NO_X and SO_2 from the 2000–2004 baseline period from EPA's Air Markets Program Data[53] and modeled these emission rates as constant emission rates for the entire modeled year. For some of the modeled BART-eligible sources, evaluation of baseline emissions revealed evidence of installation of NO_X control technology during the baseline period. For those sources the maximum emission rate was identified from the post-control portion of the baseline period. Because daily emissions are not available for PM, the annual average emission rate was doubled to approximate the 24-hr maximum emission rate for PM. A BART-eligible source that is shown not to contribute significantly to visibility impairment at any of the Class I areas using CAMx modeling may be excluded from further steps in the BART process. The maximum modeled impact for each source (calculated based on annual average natural background conditions) was compared to the 0.5 dv contribution threshold. See the BART Screening TSD for additional details on the CAMx modeling performed and the model inputs used. The table below summarizes the results of the CAMx screening analysis. As shown in the table below, all sources analyzed with CAMx modeling had impacts greater than 0.5 dv at one or more Class I areas. The most impacted Class I areas based on these results are Wichita Mountains National Wildlife Refuge in Oklahoma (WIMO), Caney Creek Wilderness Area in Arkansas (CACR), and Salt Creek Wilderness Area in New Mexico (SACR). CAMx modeled impacts at single locations for these sources (maximum impact day) ranged from 0.845 dv to 10.498 dv.

[48] *http://ampd.epa.gov/ampd/.*

[49] When we use the term ''gas,'' we mean ''pipeline quality natural gas.''

[50] CAMx results were also obtained and add to our basis of information for coal-fired facilities that have CALPUFF results.

[51] See TX RH SIP Appendix 9–5, ''Screening Analysis of Potential BART-Eligible Sources in Texas''; Revised Draft Final Modeling Protocol Screening Analysis of Potentially BART-Eligible Sources in Texas, Environ Sept. 27, 2006; and Guidance for the Application of the CAMx Hybrid Photochemical Grid Model to Assess Visibility Impacts of Texas BART Sources at Class I Areas, Environ December 13, 2007 all available in the docket for this action.

[52] We approved Texas' subject-to-BART analysis for non-EGU sources which relied on this CAMx modeling in our January 5, 2016 rulemaking (81 FR 296).

[53] *http://ampd.epa.gov/ampd/.*

TABLE 5—CAMX BART SCREENING SOURCE ANALYSIS RESULTS

BART-eligible source	Units	Most impacted Class I area	Maximum delta-dv	Less than 0.5 dv?	Number of modeled days over 0.5 dv [2]	Number of modeled days over 1.0 dv [2]
Big Brown	1 & 2	WIMO	4.017	No	65	33
Coleto Creek	1	WIMO	0.845	No	9	0
Fayette Power	1 & 2	CACR	1.894	No	26	9
Harrington	061B & 062B	SACR	5.288	No	13	5
Martin Lake	1, 2, & 3	CACR	6.651	No	141	99
Monticello	1, 2, & 3	CACR	10.498	No	152	111
Calaveras	J T Deely 1 & 2, OW Sommers 1 & 2.	WIMO	1.513	No	47	6
W A Parish	WAP4, WAP5 & WAP6	CACR	3.177	No	54	22
Welsh [1]	1 & 2	CACR	4.576	No	92	39

[1] Welsh unit 2 has recently shutdown. We note that baseline impacts from unit 1 alone are 2.343 dv at Caney Creek.
[2] Number of days over 0.5 or 1.0 dv at the most impacted Class I area.

5. Summary of Sources that are Subject to BART

Based on the four methodologies described above, the BART-eligible sources in the table below have been determined to cause or contribute to visibility impairment at a nearby Class I area, and we therefore propose to find the sources are subject-to-BART. They are subject to review for visibility impairing pollutants other than NO_X.[54] Foremost, they are subject to SO_2 BART, the visibility impairing pollutant that is the main contributor to the regional haze problem at Class I areas in Texas and neighboring states. The sources are also subject to review for source-specific BART requirements for PM.

TABLE 6—SUMMARY: SOURCES THAT ARE SUBJECT-TO-BART

Facility	Units
Big Brown	1 & 2.
Coleto Creek	1.
Fayette Power	1 & 2.
Harrington	061B & 062B.
Martin Lake	1, 2 & 3.
Monticello	1, 2 & 3.
Calaveras	J T Deely 1 & 2, O W Sommers 1 & 2.
W A Parish	WAP4, WAP5 & WAP6.
Welsh	1 & 2*.
Stryker	ST2.
Graham	2.
Wilkes	1, 2 & 3.
Newman	2, 3 & 4.

* Welsh Unit 2 retired in April, 2016.

C. Our BART Five Factor Analyses

The purpose of the BART analysis is to identify and evaluate the best system of continuous emission reduction based on the BART Guidelines.[55] In determining BART, a state, or EPA when promulgating a FIP, must consider the five statutory factors in section 169A of the CAA: (1) The costs of compliance; (2) the energy and nonair quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. See also 40 CFR 51.308(e)(1)(ii)(A). This is commonly referred to as the ''BART five factor analysis.'' The BART Guidelines break the analyses of these requirements down into five steps: [56]

STEP 1—Identify All Available Retrofit Control Technologies,
STEP 2—Eliminate Technically Infeasible Options,
STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,
STEP 4—Evaluate Impacts and Document the Results, and
STEP 5—Evaluate Visibility Impacts.

The following sections treat these steps individually for SO_2. We are combining these steps into one section in our assessment of PM BART that follows the SO_2 sections.

1. Steps 1 and 2: Technically Feasible SO_2 Retrofit Controls

The BART Guidelines state that in identifying all available retrofit control options,

> [Y]ou must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.[57]

Adhering to this, we will identify a reasonable set of SO_2 control options, including those that cover the maximum level of control each technology is capable of achieving. In the course of that task, we will note whether any of these technologies are technically infeasible.

The subject-to-BART units identified in Table 6 can be organized into four broad categories, based on their fuel type and the potential types of SO_2 controls that could be retrofitted: (1) Coal-fired EGUs with no SO_2 scrubber, (2) coal-fired EGUs with underperforming SO_2 scrubbers, (3) gas-fired EGUs that do not burn oil, and (4) gas-fired EGUs that occasionally burn fuel oil. This classification is represented below:

[54] The NO_X BART requirement for these EGU sources is not addressed by source-specific limits in this proposal. According to our proposal, participation in CSAPR, in its updated form, would serve as a BART alternative, dispensing with the need for source-specific BART determinations and requirements for NO_X.

[55] See July 6, 2005 BART Guidelines, 40 CFR part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations.

[56] 70 FR 39104, 39164 (July 6, 2005) [40 CFR part 51, App. Y].

[57] 70 FR at 39164, fn 12 [40 CFR part 51, App. Y]

TABLE 7—SUBJECT TO BART FUEL TYPES AND POTENTIAL SO_2 BART CONTROLS

Facility	Unit	Coal no scrubber	Coal underperforming scrubber	Gas no oil	Gas burns oil
Big Brown (Luminant)	1	X			
Big Brown (Luminant)	2	X			
Coleto Creek (Engie)	1	X			
Fayette (LCRA) *	1				
Fayette (LCRA) *	2				
Graham (Luminant)	2				X
Harrington Station (Xcel)	061B	X			
Harrington Station (Xcel)	062B	X			
J T Deely (CPS Energy)	1	X			
J T Deely (CPS Energy)	2	X			
Martin Lake (Luminant)	1		X		
Martin Lake (Luminant)	2		X		
Martin Lake (Luminant)	3		X		
Monticello (Luminant)	1	X			
Monticello (Luminant)	2	X			
Monticello (Luminant)	3		X		
Newman (El Paso Electric)	2				X
Newman (El Paso Electric)	3				X
Newman (El Paso Electric)	4			X	
O W Sommers (CPS Energy)	1				X
O W Sommers (CPS Energy)	2				X
Stryker Creek (Luminant)	ST2				X
W A Parish (NRG)	WAP4			X	
W A Parish (NRG)	WAP5	X			
W A Parish (NRG)	WAP6	X			
Welsh Power Plant (AEP)	1	X			
Wilkes Power Plant (AEP)	1				X
Wilkes Power Plant (AEP)	2			X	
Wilkes Power Plant (AEP)	3			X	

* The Fayette units have high performing wet Flue Gas Desulfurization scrubbers in place.

For the coal-fired EGUs without an existing scrubber, we have identified four potential control technologies: (1) Coal pretreatment, (2) Dry Sorbent Injection (DSI), (3) Spray Dryer Absorber (SDA), and (4) wet Flue Gas Desulfurization (FGD.) For the coal-fired EGUs with an existing underperforming scrubber we will examine whether that scrubber can be upgraded.

Gas-fired EGUs that do not burn oil have inherently very low SO_2 emissions and there are no known SO_2 controls that can be evaluated.

For gas-fired units that occasionally burn fuel oil, we will follow the BART Guidelines recommendations for oil-fired units: ''For oil-fired units, regardless of size, you should evaluate limiting the sulfur content of the fuel oil burned to 1 percent or less by weight.'' [58] In addition, we will also evaluate the potential for post combustion SO_2 controls for these units.

a. Identification of Technically Feasible SO_2 Retrofit Control Technologies for Coal-Fired Units

Available SO_2 control technologies for coal-fired EGUs consist of either pretreating the coal in order to improve its qualities, or treating the flue gas through the installation of either DSI or some type of scrubbing technology.

Coal Pretreatment

Coal pretreatment, or coal upgrading, has the potential to reduce emissions by reducing the amount of coal that must be burned in order to result in the same heat input to the boiler. Coal pretreatment broadly falls into two categories: coal washing and coal drying.

Coal washing is often described as preparation (for particular markets) or cleaning (by reducing the amount of mineral matter and/or sulphur in the product coal).[59] Washing operations are carried out mainly on bituminous and anthracitic coals, as the characteristics of subbituminous coals and lignite (brown coals) do not lend themselves to separation of mineral matter by this means, except in a few cases.[60] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of preparation.[61] Following the coal washing, the coal is dewatered, and the waste streams are disposed.

Coal washing takes place offsite at large dedicated coal washing facilities, typically located near where the coal is mined. In addition, coal washing carries with it a number of problems:

- Coal washing is not typically performed on the types of coals used in the power plants under consideration, Powder River Basin (PRB) subbituminous and Texas lignites.

[58] 70 FR 39171 (July 6, 2005) [40 CFR 51, App. Y].

[59] Couch, G.R., ''Coal Upgrading to Reduce CO_2 emissions,'' CCC/67, October 2002, IEA Clean Coal Centre.

[60] Ibid.

[61] Various coal washing techniques are treated in detail in Chapter 4 of *Meeting Projected Coal Production Demands In The USA, Upstream Issues, Challenges, and Strategies,* The Virginia Center for Coal and Energy Research, Virginia Polytechnic Institute and State University, contracted for by the National Commission on Energy Policy, 2008.

• Because coal washing is not typically conducted onsite of the power plant, it is viewed as a consideration in the selection of the coal, and not as an air pollution control.

• Coal washing poses significant energy and non-air quality considerations under section 51.308(e)(1)(ii)(A). For instance, it results in the use of large quantities of water,[62] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[63]

Because of these issues, we do not consider coal washing as a part of our reasonable set of options for analysis as BART SO_2 control technology.

In general, coal drying consists of reducing the moisture content of lower rank coals, thereby improving the heating value of the coal and so reducing the amount of coal that has to be combusted to achieve the same power, thus improving the efficiency of the boiler. In the process, certain pollutants are reduced as a result of (1) mechanical separation of mineralized sulfur (*e.g.,* and iron pyrite) and rocks, and (2) the unit burning less coal to make the same amount of power.

Coal drying can be performed onsite and so can be considered a potential BART control. Great River Energy has developed a patented process which is being successfully utilized at the Coal Creek facility and is potentially available for installation at other facilities.[64] This process utilizes excess waste heat to run trains of moving fluidized bed dryers. The process offers a number of co-benefits, such as general savings due to lower coal usage (*e.g.,* coal cost, ash disposal), less power required to run mills and ID fans, and lower maintenance on coal handling equipment air preheaters, etc.

Although we view this new patented technology for coal drying onsite as a promising path in the near future for generally improving boiler efficiency and obtaining some reduction in SO_2, its analysis presents a number of difficulties. For instance, the degree of reduction in SO_2 is dependent on a number of factors. These include (1) the quality and quantity of the waste heat available at the unit, (2) the type of coal being dried (amount of bound sulfur, *i.e.,* pyrites, moisture content), and (3) the design of the boiler (*e.g.,* limits to steam temperatures, which can decrease due to the reduced flue gas flow through the convective pass of the boiler). We cannot assess many of these site-specific issues and we believe that requesting that the facilities in question do so would require detailed engineering analysis and extend our review time greatly. As a result of these issues, we do not further assess coal drying as part of our reasonable set of options for BART analysis. We expect that this technology may have matured enough such that it can be better assessed for the second planning period.

DSI

DSI is performed by injecting a dry reagent into the hot flue gas, which chemically reacts with SO_2 and other gases to form a solid product that is subsequently captured by the particulate control device. A blower delivers the sorbent from its storage silos through piping directly to the flue gas ducting via injection lances. The most commonly used sorbent is trona, a naturally occurring mineral primarily mined from the Green River Formation in Wyoming. Trona can also be processed into sodium bicarbonate, which is more reactive with SO_2 than trona, but more expensive. Hydrated lime is another potential sorbent but it is less frequently used and little data are available regarding its potential performance and cost. In general, trona is considered the most cost-effective of the sorbents for SO_2 removal. There are many examples of DSI being used on coal-fired EGUs to control SO_2. However, DSI may not be technically feasible at every coal-fired EGU. For instance, Luminant states in its response to one of our Section 114(a) letters regarding its Big Brown and Monticello units: [65]

> Luminant commissioned the study of dry sorbent injection (''DSI'') at these units in 2011. These studies determined that a very high feed rate (in the range of 20–30%) was required to achieve modest SO_2 removal. Further, it was determined that other economic and operational factors make the use of DSI infeasible. For example, sorbent build-up was determined to cause degraded performance of the control equipment over time, as well as significant, repeat down time on a regular basis (*i.e.,* every few days) to remove the buildup. In addition to the high cost of the sorbent required, the disposal and transport of the used sorbent (a Texas Class 1 waste) would result in significant additional cost. Thus, the use of DSI was determined infeasible from both an operational and economic point of view, and further evaluation has been discontinued.

As a consequence of this statement, which is discussed more fully in the CBI material Luminant has submitted and in our TSD, we have concluded that DSI is not a feasible alternative for the Big Brown and Monticello facilities. For all unscrubbed, coal-fired BART-subject units other than the Big Brown and Monticello facilities, although individual installations may present technical difficulties or poor performance due to the suboptimization of one or more of the above factors, we believe that DSI is technically feasible and should be considered as a potential BART control.

SO_2 Scrubbing Systems

In contrast to DSI, SO_2 scrubbing techniques utilize a large dedicated vessel in which the chemical reaction between the sorbent and SO_2 takes place either completely or in large part. Also in contrast to DSI systems, SO_2 scrubbers add water to the sorbent when introduced to the flue gas. The two predominant types of SO_2 scrubbing employed at coal-fired EGUs are wet FGD, and Spray Dry Absorber (SDA). More recently, Circulating Dry Scrubbers (CDS) have been introduced. The EIA reports the following types of flue gas desulfurization systems as being operational in the U.S. for 2015:

TABLE 8—EIA REPORTED DESULFURIZATION SYSTEMS IN 2015

Type	Number of installations
Wet spray tower scrubber	296
Spray dryer absorber	269
Circulating dry scrubber	50
Packed tower wet scrubber	6
Venturi wet scrubber	48
Jet bubbling reactor	31
Tray tower wet scrubber	42
Mechanically aided wet scrubber.	4
DSI	106
Other	1
Unspecified	1
Total	854

Excluding the DSI installations, EIA lists 748 SO_2 scrubber installations in operation in 2015. Of these, 296 are listed as being spray type wet scrubbers, with an additional 42 listed as being

[62] ''Water requirements for coal washing are quite variable, with estimates of roughly 20 to 40 gallons per ton of coal washed (1 to 2 gal per MMBtu) (Gleick, 1994; Lancet, 1993).'' Energy Demands on Water Resources, Report to Congress on the Interdependency of Energy and Water, U.S. Department Of Energy, December 2006.

[63] Committee on Coal Waste Impoundments, Committee on Earth Resources, Board on Earth Sciences and Resources, Division on Earth and Life Studies; *Coal Waste Impoundments, Risks, Responses, and Alternatives;* National Research Council; National Academy Press, 2002.

[64] DryFining™ is the company's name for the process. It is described here: *http://www.powermag.com/improve-plant-efficiency-and-reduce-co2-emissions-when-firing-high-moisture-coals/.*

[65] Luminant's 6/17/14 response to EPA's 5/20/14 Section 114(a) request for information relating to the Big Brown, Martin Lake, Monticello, and Sandow generating stations.

tray type wet scrubbers.[66] An additional 269 are listed as being spray dry absorber types. Consequently, spray type or tray type wet scrubbers (wet FGD) account for approximately 45% of all scrubber systems, and spray dry scrubbers (SDA) account for approximately 36% of all scrubber systems that were operational in the U.S. in 2015.

We consider some of the other scrubber system types (*e.g.,* venturi and packed wet scrubber types) to be older, outdated technologies (that are not existing controls or factor into considerations regarding existing controls) and therefore will not be considered in our BART analysis. Jet bubbling reactors and circulating dry scrubbers are relatively new technologies, with limited installations, and little information is available with which to characterize them or their suitability as a retrofit control option. Therefore, they too will not be further considered as part of our reasonable set of options for analysis for BART controls.

In summary, wet FGD and SDA installations account for approximately 81% of all scrubber installations in the U.S. and as such constitute a reasonable set of SO_2 scrubber control options. The vast majority of the wet FGD and SDA installations utilize limestone and lime, respectively as reagents. In addition, these technologies cover the maximum level of SO_2 control available. As described above, these controls are in wide use and have been retrofitted to a variety of boiler types and plant configurations. We therefore see no technical infeasibility issues and believe that limestone wet FGD and lime SDA should be considered as potential BART controls for all of the unscrubbed coal-fired BART-eligible units.

b. Identification of Technically Feasible SO_2 Retrofit Control Technologies for Gas-Fired Units that Burn Oil

Reduction in Fuel Oil Sulfur

A number of the units we proposed in Table 6 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past as reported by the EIA databases: EIA–767, EIA–906/920, and EIA–923,[67] which indicate the historic quantities of fuel oil burned and the type and sulfur content of that fuel oil. These units are identified below in Table 9:

TABLE 9—GAS UNITS THAT OCCASIONALLY BURN OIL AND ARE SUBJECT TO BART

Facility	Unit(s)	Gas turbine	Steam turbine
Graham (Luminant)	2		X
Newman (El Paso Electric)	2, 3		X
O W Sommers (CPS Energy)	1, 2		X
Stryker Creek (Luminant)	ST2		X
Wilkes Power Plant (AEP)	1		X

The BART Guidelines advise that for oil-fired units, regardless of size, limits on fuel oil sulfur content should be considered in the BART evaluation.[68] All of the subject units are limited by permit to burning oil with a sulfur content of no more than 0.7% sulfur by weight.[69] In analyzing the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we investigated two issues: (1) Is lower sulfur fuel oil available and what is its cost, and (2) are there any technical issues in burning a lower sulfur fuel oil that could add to the cost of that oil? All of the units have either burned Distillate Fuel Oil (DFO) or have switched between DFO and Residual Fuel Oil (RFO), thus demonstrating the ability to burn DFOs of the type under consideration for SO_2 BART. We therefore conclude that lower sulfur DFOs are a technically feasible retrofit control option under BART. Lower sulfur DFOs carry no capital costs. Any cost increases relate to purchase price differences.

SO_2 Scrubber Feasibility for Gas/Oil-Fired Boilers

We are aware of instances in which FGDs of various types have been installed or otherwise deemed feasible on a boiler that burns oil.[70] Consequently, we will consider the installation of various types of scrubbers to be technically feasible.

c. Identification of Technically Feasible SO_2 Control Technologies for Scrubber Upgrades

In our recent Texas-Oklahoma FIP,[71] we presented a great deal of information that concluded that the existing scrubbers for a number of facilities could be very cost-effectively upgraded.[72] That information is included in this proposal.[73] It contains a comprehensive survey of available literature concerning the kinds of upgrades that have been performed by industry on scrubber systems similar to the ones installed on the units included in this proposal. We then reviewed all of the information we had at our disposal regarding the status of the existing scrubbers for each unit, including any upgrades the facility may have already installed. We finished by calculating the cost-effectiveness of scrubber upgrades, using the facility's own information, obtained as a result of our Section 114 collection efforts. The companies that supplied this information have asserted a Confidential Business Information (CBI) claim for much of it, as provided in 40 CFR 2.203(b). We therefore redacted any CBI information we utilize in our analyses, or otherwise disguised it so that it cannot be traced back to its specific source. Of the facilities we evaluated for scrubber upgrades in that action, Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are subject to BART and are thus a part of this proposal.

[66] Trays are often employed in spray type wet scrubbers and EIA lists some of the wet spray tower systems as secondarily including trays.

[67] EIA-767: *http://www.eia.gov/electricity/data/eia767/*. EIA–906/920 and EIA–923: *http://www.eia.gov/electricity/data/eia923/*.

[68] 70 FR at 39171.

[69] In addition, the Newman units 2 and 3 are restricted to burning fuel oil for no more than 10% of their annual operating time.

[70] Crespi, M. ''Design of the FLOWPAC WFGD System for the Amager Power Plant.'' Power-Gen FGD Operating Experience, November 29, 2006, Orlando, FL.

Babcock and Wilcox. ''Wet Flue Gas Desulfurization (FGD) Systems Advanced Multi-Pollutant Control Technology.'' See Page 4: ''We have also provided systems for heavy oil and Orimulsion fuels.''

DePriest, W; Gaikwad, R. ''Economics of Lime and Limestone for Control of Sulfur Dioxide.'' See page 7: ''A CFB unit, in Austria, is on a 275 MW size oil-fired boiler burning 1.0–2.0% sulfur oil.''

[71] 81 FR 321.

[72] See information presented in Sections 6 and 7 of the Cost TSD.

[73] That information is included in our BART FIP TSD, Appendix B.

2. Step 3: Evaluation of SO_2 Control Effectiveness

In the following subsections, we evaluate the control levels each technically feasible technology is capable of achieving for the coal and gas units. In so doing, we consider the maximum level of control each technology is capable of delivering based on a 30 Boiler Operating Day (BOD) period. As the BART Guidelines direct, ''[y]ou 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.'' [74] To calculate a 30-day rolling average based on BOD, the average of the last 30 ''boiler operating days'' is used. In other words, days are skipped when the unit is down, as for maintenance. In effect, this provides a margin of safety by eliminating spikes that occur at the beginning and end of outages.

a. Evaluation of SO_2 Control Effectiveness for Coal Fired Units

Control Effectiveness of DSI

We lack the site-specific information, which we believe requires an individual performance test, in order to be able to accurately determine the maximum DSI SO_2 removal efficiency for the individual units listed in Table 7. We are aware that a number of the subject-to-BART coal-fired units have conducted such testing. However, although we have examined that testing, most of the facilities have claimed it as CBI and requested protection from public disclosure as provided by 40 CFR part 2.

However, we nevertheless must evaluate DSI as a viable, proven method of SO_2 control. We must do the same for SO_2 scrubbing, and in so doing, compare the visibility benefits and costs of each technology in order to inform our proposed BART determinations. We therefore propose the following methodology:

- We will evaluate each unit at its maximum recommended DSI performance level, according to the IPM DSI documentation,[75] assuming milled trona: 80% SO_2 removal for an ESP installation and 90% SO_2 removal for a baghouse installation. This level of control is within the range that can be achieved by SO_2 scrubbers, and thus allows a better comparison of the costs of DSI and scrubbers.
- However, (1) we do not know whether a given unit is actually capable of achieving these control levels and (2) we believe it is useful to evaluate lesser levels of DSI control (and correspondingly lower costs). We therefore also evaluate all the units at a DSI SO_2 control level of 50%, which we believe is likely achievable for most units.
- We invite comments on whether particular units have performed DSI testing and have concluded they cannot achieve a SO_2 reduction between 50% and 80/90%. Any data to support such a conclusion should be submitted along with those comments.

Control Effectiveness of Wet FGD and SDA

We have assumed a wet FGD level of control to be a maximum of 98% not to go below 0.04 lbs/MMBtu, in which case, we assume the percentage of control equal to 0.04 lbs/MMBtu. As we discuss later in this proposal, we will conduct our wet FGD control cost analysis using the wet FGD cost algorithms, as employed in version 5.13 of our IPM model.[76] The IPM wet FGD Documentation states: ''The least squares curve fit of the data was defined as a ''typical'' wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of wet FGD systems, are 0.04 lb/MMBtu.'' As we established in our Oklahoma FIP,[77] this level of control is achievable with wet FGD. This level of control was also employed in our recent Texas-Oklahoma FIP.[78] We received a comment challenging this level of control and we responded to that comment in our final action on our Texas-Oklahoma FIP and incorporate that response in this proposed action.[79] We continue to conclude that our proposed level of control for wet FGD is reasonable.

As with our Oklahoma FIP, we have assumed a SDA level of control equal to 95%, unless that level of control would fall below an outlet SO_2 level of 0.06 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu. See our response to comments in our previous Oklahoma FIP.[80] In that FIP, we finalized the same emission limit of 0.06 lbs/MMBtu on a 30 BOD average for 6 coal-fired EGUs. We justified those limits based on the same SDA technology, using a combination of industry publications and real world monitoring data. Much of that information is summarized in our response to a comment to that action [81] and in our TSD. We continue to conclude that our proposed level of control for SDA is reasonable.

b. Evaluation of SO_2 Control Effectiveness for Gas Fired Units

The control effectiveness of switching from a higher sulfur fuel oil to a lower sulfur fuel oil lies in the reduction in sulfur emissions. The emissions reduction depends on the percentage reduction from the sulfur contents of the fuel oil that forms the SO_2 baseline to the replacement fuel oil. Ultimately, the highest level of control would result from a switch from the highest percentage sulfur the units are permitted to burn, 0.7% to the lowest DFO available, ultra-low sulfur diesel, which has a sulfur content of 0.0015%. This would equate to a control effectiveness of 99.8%. Lesser levels of controls are also possible. We will evaluate a range of control effectiveness in switching to lower sulfur fuel oils in the next section.

[74] 70 FR 39103, 39172 (July 6, 2005), [40 CFR part 51, App. Y].

[75] IPM Model—Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy, p. 7.

[76] IPM Model—Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5–5: DSI Cost Methodology, downloaded *https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-5_dsi_cost_methodology.pdf.*

IPM Model—Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v. 5.13: Chapter 5: Emission Control Technologies, Attachment 5–2: SDA FGD Cost Methodology, downloaded from *https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-2_sda_fgd_cost_methodology_3.pdf.*

IPM Model—Updates to Cost and Performance for APC Technologies, wet FGD Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5–1: Wet FGD Cost Methodology, downloaded from *https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-1_wet_fgd_cost_methodology.pdf.*

[77] As discussed previously in our TSD for that action, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95% and 98% respectively. 76 FR 81742); *Oklahoma* v. *EPA*, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014).

[78] 81 FR 321.

[79] That information is included in our BART FIP TSD, Appendix A.

[80] 76 FR 81728.

[81] Response to Technical Comments for Sections E through H of the **Federal Register** Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA–R06–OAR–2010–0190, 12/13/2011. See comment and response beginning on page 91.

Because we are unaware of any scrubber installations on oil fired units in the U.S., we have no information on their control effectiveness. However, we see no technical reason why the control effectiveness of FGDs installed on gas-fired units that occasionally burn fuel oil should not be equal to that of FGDs installed on coal-fired units.

3. Step 4: Evaluate Impacts and Document the Results for SO_2

The BART Guidelines offers the following with regard to how Step 4 should be conducted: [82]

After you identify the available and technically feasible control technology options, you are expected to conduct the following analyses when you make a BART determination:

Impact analysis part 1: Costs of compliance,
Impact analysis part 2: Energy impacts, and
Impact analysis part 3: Non-air quality environmental impacts.
Impact analysis part 4: Remaining useful life.

We evaluate the cost of compliance on a unit-by unit basis, because control cost analysis depends on specific factors that can vary from unit to unit. However, we generally evaluate the energy impacts, non-air quality impacts, and the remaining useful life for all the units in question together because in this instance there are no appreciable differences in these factors from unit to unit.[83]

In developing our cost estimates for the units in Table 7, we rely on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[84] We proceed in our SO_2 costing analyses by examining the current SO_2 emissions and the level of SO_2 control, if any, for each of the units listed in Table 7. For the coal units without any SO_2 control, we calculate the cost of installing DSI, a SDA scrubber, and a wet FGD scrubber. For the gas units that burn oil, we evaluate the cost of switching to lower sulfur fuel oils and installing scrubbers.

In order to estimate the costs for DSI, SDA scrubbers, and wet FGD scrubbers, we programmed the DSI, SDA and wet FGD cost algorithms, as employed in version 5.13 of our IPM model, referenced above, into three spreadsheets. These cost algorithms calculate the Total Project Cost (TPC), Fixed Operating and Maintenance (Fixed O&M) costs, and Variable Operating and Maintenance (Variable O&M) costs. We then performed DSI, SDA and wet FGD cost calculations for each unit listed in Table 7 that did not already have SO_2 control.[85] These cost models were based on costs escalated to 2012 dollars.[86] Because the IPM 5–13 cost algorithms were calculated in 2012 dollars, we have escalated them to 2016, using the annual Chemical Engineering Plant Cost Indices (CEPCI).

a. Impact Analysis Part 1: Cost of Compliance for DSI, SDA, and Wet FGD

As we discuss above and in our Cost TSD, we evaluated each unit at its maximum recommended level of control, considering the type of SO_2 control device. Below, we present a summary of our DSI, SDA, and wet FGD cost analysis: [87]

TABLE 10—SUMMARY OF DSI, SDA, AND WET FGD COST ANALYSIS

Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized cost	2016 Cost effectiveness ($/ton)	2016 Incremental cost-effectiveness ($/ton)
Big Brown	1	DSI	50	14,448	$29,468,587	$2,040	
		DSI	90	26,006	72,131,749	2,774	$3,691
		SDA	95	27,453	35,297,532	1,286	−25,456
		Wet FGD	98	28,320	33,673,102	1,189	−1,874
	2	DSI	50	15,320	29,342,350	1,915	
		DSI	90	27,576	71,322,593	2,586	3,425
		SDA	95	29,108	35,359,239	1,215	−23,475
		Wet FGD	97.9	29,998	33,817,952	1,127	−1,732
Monticello	1	DSI	50	4,787	11,408,872	2,383	
		DSI	90	8,617	25,409,128	2,949	3,655
		SDA	95	9,095	24,294,319	2,671	−2,332
		Wet FGD	97	9,286	25,236,699	2,718	4,934
	2	DSI	50	4,129	9,742,648	2,360	
		DSI	90	7,431	21,418,734	2,882	3,536
		SDA	95	7,844	23,126,113	2,948	4,134
		Wet FGD	96.8	7,995	24,233,133	3,031	7,331
Coleto Creek	1	DSI	50	7,376	16,246,169	2,203	
		DSI	90	13,277	34,841,379	2,624	3,151
		SDA	92.4	13,632	29,445,018	2,160	−15,201
		Wet FGD	94.9	14,005	29,786,106	2,127	914
Harrington	061B	DSI	50	2,477	9,187,608	3,710	
		DSI	80	3,962	16,073,779	4,057	4,637
		SDA	90.2	4,466	17,455,679	3,909	2,742
	062B	DSI	50	2,455	6,524,937	2,658	
		DSI	* 88.9	4,364	11,981,111	2,746	2,858
		SDA	88.9	4,364	18,240,127	4,180	N/A
J T Deely	1	DSI	50	3,072	8,854,319	2,883	

[82] 70 FR 39166.

[83] To the extent these factors inform the cost of controls, consistent with the BART Guidelines, they do inform our considerations on a unit-by-unit basis.

[84] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B–02–001, January 2002 available at *http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf*.

[85] These spreadsheets are entitled, ''DSI Cost IPM 5–13 TX BART.xlsx,'' ''SDA Cost IPM 5–13 TX BART.xlsx,'' and ''Wet FGD Cost IPM 5–13 TX BART.xlsx,'' and are located in our Docket.

[86] Ibid., p.1: ''The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data.''

[87] In this table, the capital cost is the total cost of constructing the facility. The annualized cost is the sum of the annualized capital cost and the annualized operational cost. See our Cost TSD for more information on how these costs were calculated.

TABLE 10—SUMMARY OF DSI, SDA, AND WET FGD COST ANALYSIS—Continued

Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized cost	2016 Cost effectiveness ($/ton)	2016 Incremental cost-effectiveness ($/ton)
		DSI	90	5,529	18,071,878	3,269	3,752
		SDA	91.3	5,609	21,689,526	3,867	45,221
		Wet FGD	94.2	5,787	22,555,395	3,898	4,864
	2	DSI	50	3,222	9,865,798	3,062	
		DSI	90	5,800	20,229,233	3,488	4,020
		SDA	91.3	5,884	21,812,518	3,707	18,849
		Wet FGD	94.2	6,070	22,530,901	3,712	3,862
Welsh	1	DSI	50	3,343	8,963,761	3,469	
		DSI	* 87.2	5,832	23,090,408	3,960	5,676
		SDA	87.2	5,832	22,697,048	3,892	N/A
		Wet FGD	91.5	6,116	23,998,161	3,924	4,581
W.A. Parish	5	DSI	50	6,712	15,002,337	2,235	
		DSI	90	12,081	30,865,711	2,555	2,955
		SDA	92.1	12,364	31,195,787	2,523	1,166
		Wet FGD	94.7	12,717	30,735,030	2,417	−1,305
	6	DSI	50	7,525	16,014,988	2,128	
		DSI	90	13,545	33,302,528	2,459	2,872
		SDA	92.1	13,862	32,758,784	2,363	−1,715
		Wet FGD	94.7	14,258	32,215,226	2,259	−1,373

* DSI control level limited to that of SDA.

b. Impact Analysis Part 1: Cost of Compliance for Scrubber Upgrades

In our BART FIP TSD, we analyze those units listed in Table 7 with an existing SO_2 scrubber in order to determine if cost-effective scrubber upgrades are available. Of our subject-to-BART units, Martin Lake Units 1, 2, 3; Monticello Unit 3, and Fayette Units 1 and 2 are currently equipped with wet FGDs. Of these, all but the Fayette units were analyzed for scrubber upgrades in our Texas-Oklahoma FIP. For all but the Fayette units, we propose to adopt the total annualized cost calculations used to make the cost-effectiveness calculations in our Texas-Oklahoma FIP in this action. We acknowledge that these costs could change slightly, due to changes in the costs of various materials and services. However, these costs were calculated in 2013 dollars. Escalating them to 2015 dollars would result in a reduction in cost, which we conservatively do not take into consideration.[88]

In our Texas-Oklahoma FIP action, after responding to comments we revised our proposed cost-effectiveness basis from where all scrubber upgrades were less than $600/ton, to where all scrubber upgrades ranged from between $368/ton to $910/ton.[89] As with our Texas-Oklahoma FIP, we are limited in what information we can include in this section, because we used information that was claimed as CBI. This information was submitted in response to our Section 114(a) requests. The following summary is based on information not claimed as CBI.

- The absorber system had either already been upgraded to perform at an SO_2 removal efficiency of at least 95%, or it could be upgraded to perform at that level using proven equipment and techniques.
- The SO_2 scrubber bypass could be eliminated, and the additional flue gas could be treated by the absorber system with at least a 95% removal efficiency.
- Additional modifications necessary to eliminate the bypass, such as adding fan capacity, upgrading the electrical distribution system, and conversion to a wet stack could be performed using proven equipment and techniques.
- The additional SO_2 emission reductions resulting from the scrubber upgrade are substantial, ranging from 68% to 89% reduction from the current emission levels, and are cost-effective.

We now update these calculations for 2011–2015 data.[90] The revised scrubber upgrade results for Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are presented below in Table 11:

TABLE 11—SUMMARY OF UPDATED SCRUBBER UPGRADE RESULTS

Unit	2011–2015 3-yr avg. SO_2 emissions (eliminate max and min) (tons)	SO_2 emissions at 95% control (tons)	SO_2 emissions reduction due to scrubber upgrade (tons)	SO_2 emission rate at 95% control (lbs/MMBtu)
Monticello 3	8,136	1,180	6,956	0.05
Martin Lake 1	19,040	3,208	15,832	0.12
Martin Lake 2	17,973	3,393	14,580	0.12
Martin Lake 3	16,113	2,591	13,522	0.11
Total SO_2 Removed			50,890	

[88] The CEPCI for 2013 is 567.3 and that for 2015 is 556.3. Therefore, the costs would be multiplied by a factor of 556.8/567.3, which is approximately 0.98.

[89] 81 FR 318.

[90] See Coal vs CEM data 2011–2015.xlsx.

As we note above, we updated the cost-effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost-effectiveness was $1,156/ton or less. We invite the facilities listed above to make arrangements with us to view our complete updated cost analysis for their units.

The Fayette Units 1 and 2 are currently equipped with high performing wet FGDs. Both units have demonstrated the ability to maintain a SO_2 30 BOD average below 0.04 lbs/MMBtu for years at a time.[91] As we discuss above, we evaluate BART demonstrating that retrofit wet FGDs should be evaluated at 98% control not to go below 0.04 lbs/MMBtu. Because the Fayette units are performing below this level, we propose that no scrubber upgrades are necessary. We propose to find that the Fayette Units 1 and 2 maintain a 30 Boiler Operating Day rolling average SO_2 emission rate of 0.04 lbs/MMBtu based on the actual emissions data we present above. We believe that based on its demonstrated ability to maintain an emission rate below this value on a 30 BOD basis, it can consistently achieve this emission level.

c. Impact Analysis Part 1: Cost of Compliance for Gas Units That Burn Oil

As we noted in Section III.C.1.b, a number of the units we proposed in Table 9 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past as reported by the EIA. These units are limited by their permits to burning oil with a sulfur content of no more than 0.7% sulfur by weight. We proposed to consider both a reduction in fuel oil sulfur and SO_2 scrubbers as potential BART controls. Below we consider the cost of these potential controls.

Reduction in Fuel Oil Sulfur

In order to determine the cost of these facilities switching to lower sulfur content fuel oils, we sent the Graham, Newman, Stryker Creek, and the Wilkes facilities Section 114 letters requesting certain information.[92] We received very limited information in response to one of our questions concerning the present cost of the historic fuel oil burned, and the cost of various lower sulfur replacement fuel oils. Because of this, we were unable to compile facility-specific information on the cost of switching to lower sulfur fuel oils. Consequently, we considered the best available information by consulting more general information from the EIA, which reports the prices for various refinery petroleum products on a monthly and annual basis. Below is a summary of various distillate and residual fuel oil products for 2001 to 2015, averaged across the U.S.[93]

TABLE 12—SELECTED EIA REPORTED ANNUAL REFINER PETROLEUM PRICES

Date	West Texas intermediate crude oil—Cushing Oklahoma ($/bbl)	U.S. no. 2 diesel wholesale/resale price by refiners ($/gallon)	U.S. no. 2 fuel oil wholesale/resale price by refiners ($/gallon)	U.S. no. 4 distillate wholesale/resale price by refiners ($/gallon)
2015	48.66	1.667	1.565	1.215
2014	93.17	2.812	2.741	2.333
2013	97.98	3.028	2.966	2.767
2012	94.05	3.109	3.031	
2011	94.88	3.034	2.907	2.801
2010	79.48	2.214	2.147	
2009	61.95	1.713	1.657	1.561
2008	99.67	2.994	2.745	2.157
2007	72.34	2.203	2.072	1.551
2006	66.05	2.012	1.834	1.395
2005	56.64	1.737	1.623	1.377
2004	41.51	1.187	1.125	1.033
2003	31.08	0.883	0.881	0.793
2002	26.18	0.724	0.694	0.663
2001	25.98	0.784	0.756	0.697
2000	30.38	0.898	0.886	0.778

Lacking facility-specific pricing information, for the purposes of calculating the cost of compliance, we make the following assumptions:

- No. 4 distillate is the type of fuel oil currently available that most closely approximates the types of fuel oil that were historically burned by the facilities. It is available in a range of sulfur up to the facilities' permitted maximum of 0.7% sulfur by weight or 7,000 ppm. We will use the cost of this fuel oil in constructing ''business as usual'' scenarios of the annual cost of fuel oil.
- No. 2 fuel oil is available at approximately 3,000 ppm, which roughly corresponds to the sulfur level present in No. 2 fuel oil prior to our implementation of the Ultra-Low-Sulfur Diesel (ULSD) regulations.[94] We will use the cost of this fuel oil in constructing a ''medium control'' annual cost of fuel oil.
- No. 2 diesel fuel corresponds to ULSD, with a sulfur content of 15 ppm. We will use the cost of this fuel oil in constructing a ''high control'' annual cost of fuel oil.

Having identified a reasonable set of historical and lower sulfur fuel oils, we turned to the matter of establishing SO_2 baselines. We would expect that regardless of the baseline selected, a cost-effectiveness calculation that simply depended on differing fuel oil costs and the resulting reductions in SO_2, would result in the same value. In other words, the cost-effectiveness in $/ton is independent of the SO_2 baseline, since *in this case,* it is calculated on a unit basis—the increased cost in burning a unit of fuel divided by the increased reduction in the resulting

[91] See our BART FIP TSD for graphs of this data.

[92] Copies of these letters and the facilities' responses are in our docket. We inadvertently did not send the O W Sommers a letter.

[93] EIA Refiner Petroleum Product Prices by Sales Type, available here: *http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm; http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.*

[94] 69 FR 39073: ''Both high sulfur No. 2–D and No. 2 fuel oil must contain no more than 5000 ppm sulfur,131 and currently [as of the date of our final rule, 6/29/04] averages 3000 ppm nationwide.''

SO_2. While the above is true, reported data for these units does not match this expectation. This can be illustrated by examining selected EIA and emissions data for the Graham Unit 2:

TABLE 13—GRAHAM UNIT 2 EXAMPLE DISCORDANCE IN FUEL OIL BURNED AND REPORTED SO_2

Date (month/year)	Quantity fuel oil burned (bbls)	Reported SO_2 for month (tons)	Reported EIA sulfur content (wt %)
Mar-02	9,800	21.614	0.65
Feb-03	8,400	90.389	0.66
Jun-12	18,177	0.064	0.50
Jul-12	5,657	0.07	0.50

As can be seen from the above table, even though the reported sulfur content of the fuel oil in March 2002 and February 2003 was approximately the same, and the quantity burned was fairly close, the reported SO_2 emissions were significantly different. Similarly, although the amount of fuel oil burned in June 2012 was more than three times that burned in July 2012 (at the same sulfur content), the reported SO_2 emissions in June 2012 were less than that in July 2012. Also, although the fuel oil sulfur content in the 2012 examples was only slightly less than that in the 2002/2003 examples, and the amount of fuel oil burned was the same order of magnitude, the resulting reported SO_2 emissions in 2012 were three orders of magnitude less than that in 2002/2003. We conclude that either the values for the EIA fuel quantities, the EIA fuel oil sulfur contents, and/or the reported SO_2 emissions are in error. Further examination of the CAMD emissions data for Graham and Stryker revealed that the data contained a large amount of substitute data for SO_2 emissions and heat input during periods when the units burned fuel oil.

As a consequence of this discordance between the type and amount of fuel oil burned and the reported SO_2 emissions, we cannot rely on historical SO_2 emissions to construct a baseline, because a barrel of fuel oil with a given sulfur content does not result in a consistent reported SO_2 value over time. Instead, we will conduct our cost-effectiveness analysis on the basis of unit values of 1,000 barrels, using the following assumptions:

- Fuel oil costs will be based on the 2015 U.S. average prices as reported in Table 12 for No. 4 distillate at 0.7 wt. % (the permitted maximum for all units) as the current business as usual fuel, No. 2 fuel oil at 0.3 wt. % as the moderate control option, and No. 2 diesel at 0.0015% as the high control option.
- The emission factor for calculating the tons of sulfur emitted by the three fuel oils are taken from AP 42, *Compilation of Air Pollutant Emissions Factors*.[95]

Below is the result of that calculation:

TABLE 14—COST EFFECTIVENESS OF SWITCHING TO LOWER SULFUR FUEL OILS

Level of control	Cost for 1,000 barrels baseline ($/yr)	Tons reduced for 1,000 barrels	Cost effectiveness for 1,000 barrels ($/ton)	Incremental cost-effectiveness ($/ton)
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A	
Moderate control (No. 2 fuel oil $1.565/gal)	65,730	1.26	11,218	
High control (ULSD $1.667/gal)	70,014	2.20	8,627	−2,756

We suspect our price information for ULSD may be high, as the Wilkes facility indicated in its reply to our Section 114 request that its 8/12/16 contract for oil was for ULSD, which had an index price of $1.423/gallon. Assuming this price and retaining the same price for our business as usual No. 4 distillate fuel oil of $1.215/gallon, results in a cost-effectiveness of $3,970/ton—a significant improvement in cost-effectiveness. We invite the affected facilities to provide site-specific information for delivery of ULSD.

Scrubber Retrofits

Elsewhere in our proposal, we conclude that certain types of wet scrubbers were technically feasible as potential control options for gas boilers that occasionally burn oil, similar to the ones under BART review here. Were we to calculate the cost-effectiveness of a wet FGD, similar to those under consideration for the coal units undergoing BART review, we could expect that the capital and operating costs would be on the same order, as displayed in Table 10. It is a straightforward exercise to demonstrate that the installation of such a scrubber on any of the gas-fired units that occasionally burn oil would result in a very high cost-effectiveness value.

For instance, taking the smallest total annualized wet FGD cost in Table 10, corresponding to the Harrington Unit 0161B (approximately the same size as the Graham Unit 2), results in a value of $19,145,500. Assuming a 98% reduction from a baseline equal to the largest annual SO_2 emissions from any of the gas units, 1,287 tons/year (Graham Unit 2, 2001), results in a SO_2 reduction of 1,261 tons/year. The cost-effectiveness is then $15,183/ton, which is very high for a SO_2 scrubber. In addition, the annual SO_2 values for Graham Unit 2 from 2002 to 2015, and the annual SO_2 values for the remaining units, have always been an order of magnitude less than the 2001 Graham Unit 2 value. Although we have not modeled the visibility benefit of

[95] The emission factor (lb/10^3 gal) used is 150 × S, where S = weight % sulfur, taken from AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.3, Fuel Oil Combustion, available here: *https://www3.epa.gov/ttn/chief/ap42/ch01/index.html.* Boilers >100 Million Btu/hr, No. 4 oil fired.

installing SO_2 scrubbers on these units, the visibility benefit from scrubbers is estimated to be slightly less than the amount of benefit estimated from switching to ULSD.[96]

4. Impact Analysis Parts 2, 3, and 4: Energy and Non-air Quality Environmental Impacts, and Remaining Useful Life

Regarding the analysis of energy impacts, the BART Guidelines advise, ''You should examine the energy requirements of the control technology and determine whether the use of that technology results in energy penalties or benefits.'' [97] As discussed above in our cost analyses for DSI, SDA, and wet FGD, our cost model allows for the inclusion or exclusion of the cost of the additional auxiliary power required for the pollution controls we considered to be included in the variable operating costs. We chose to include this additional auxiliary power in all cases. Consequently, we believe that any energy impacts of compliance have been adequately considered in our analyses.

Regarding the analysis of non-air quality environmental impacts, the BART Guidelines advise: [98]

Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device. You should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary environmental impacts. Scrubber effluent, for example, may affect water quality and land use. Alternatively, water availability may affect the feasibility and costs of wet scrubbers. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist or when the incremental emissions reductions potential of the more stringent control is only marginally greater than the next most-effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste is similar to those other applications. On the other hand, where you or the source owner can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BART.

The SO_2 control technologies we considered in our analysis—DSI and scrubbers—are in wide use in the coal-fired electricity generation industry. Both technologies add spent reagent to the waste stream already generated by the facilities we analyzed, but do not present any unusual environmental impacts. As discussed below in our cost analyses for DSI and SDA SO_2 scrubbers, our cost model includes waste disposal costs in the variable operating costs. Consequently, we believe that with one possible exception, any non-air quality environmental impacts have been adequately considered in our analyses. We are aware that the Harrington facility has instituted a water recycling program and obtains some of its water from the City of Amarillo.[99] Due to potential non-air quality concerns, we limit our SO_2 control analysis for Harrington to DSI and dry scrubbers.

Regarding the remaining useful life, the BART Guidelines advise: [100]

You may decide to treat the requirement to consider the source's ''remaining useful life'' of the source for BART determinations as one element of the overall cost analysis. The ''remaining useful life'' of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's OAQPS Control Cost Manual require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life will clearly exceed this time period, the remaining useful life has essentially no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculations.

We are unaware that any of the facilities we have analyzed for BART have entered into an enforceable document to shut down the applicable units earlier than what would occur under our assumed 30-year operational life.[101] As we stated in our Oklahoma FIP,[102] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. Because a DSI system is relatively simple and reliable, we have no reason to conclude that its service life would be any less than what we typically use for scrubber cost analyses. Because none of the facilities involved have entered into enforceable documents to shut down the applicable units earlier, we will continue to use a 30-year equipment life for DSI, scrubber retrofits, and scrubber upgrades, as we believe that is proper.

5. Step 5: Evaluate Visibility Impacts

Please see the BART Modeling TSD, where we describe in detail the various modeling runs we conducted, our methodology and selection of emission rates, modeling results, and final modeling analysis that we used to evaluate the benefits of the proposed controls and their associated emission decreases on visibility impairment values. Below we present a summary of our analysis and our proposed findings regarding the estimated visibility benefits of emission reductions based on the CALPUFF and/or CAMx modeling results.

a. Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units depicted in Tables 15 and 16 below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2 control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 300 to 400 km of a Class

[96] For example, switching from 0.7% sulfur fuel oil to ULSD at 0.0015% sulfur results in a reduction in sulfur emissions of 99.8% compared to an estimated 98% reduction due to the use of a scrubber.

[97] 70 FR 39103, 39168 (July 6, 2005), [40 CFR part 51, App. Y.].

[98] 70 FR at 39169 (July 6, 2005), [40 CFR part 51, App. Y.].

[99] *http://www.powermag.com/xcel-energys-harrington-generating-station-earns-powder-river-basin-coal-users-group-award/.*

[100] 70 FR 39103, 39169, [40 CFR part 51, App. Y.].

[101] We received a November 21, 2016 letter from the source owner regarding Parish Units 5 & 6. The letter, now added to the docket, explains the units have natural gas firing capabilities and expresses interest in obtaining flexibility to avoid BART or obtaining multiple options for complying with BART. While we acknowledge this interest, the letter does not provide or commit to any specifics in furtherance of the BART analysis that EPA is now required to conduct under the BART Guidelines.

[102] Response to Technical Comments for Sections E. through H. of the **Federal Register** Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA–R06–OAR–2010–0190, 12/13/2011. See discussion beginning on page 36.

I area, we utilized CALPUFF and CAMx modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. In evaluating the impacts and benefits of potential controls, we utilized a number of metrics, including change in deciviews and number of days impacted over 0.5 dv and 1.0 dv. Consistent with the BART Guidelines, the visibility impacts and benefits modeled in CALPUFF and CAMx are calculated as the change in deciviews compared against natural visibility conditions.[103] We note that the high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see our BART Modeling TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

TABLE 15—VISIBILITY BENEFIT OF RETROFIT CONTROLS: COAL-FIRED UNITS (CAMX MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days >0.5 dv	65	33	0	32	65
			Days >1.0 dv	33	13	0	20	33
		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days >0.5 dv	91	62	4	29	87
			Days >1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days >0.5 dv	33	13	0	20	33
			Days >1.0 dv	12	1	0	11	12
		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days >0.5 dv	58	22	0	36	58
			Days >1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days >0.5 dv	34	13	0	21	34
			Days >1.0 dv	12	1	0	11	12
		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days >0.5 dv	58	23	0	35	58
			Days >1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1, 2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days >0.5 dv	152	107	28	45	124
			Days >1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days >0.5 dv	67	35	4	32	63
			Days >1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days >0.5 dv	79	43	3	36	76
			Days >1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989
			Days >0.5 dv	30	10	0	20	30
			Days >1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924
			Days >0.5 dv	78	42	1	36	77
			Days >1.0 dv	30	13	0	17	30
		WIMO	Max dv	2.189	1.252	0.186	0.937	2.003
			Days >0.5 dv	30	10	0	20	30
			Days >1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIMO	Max dv	0.845	0.526	0.176	0.318	0.668
			Days >0.5 dv	9	1	0	8	9
			Days >1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days >0.5 dv	5	0	0	5	5
			Days >1.0 dv	0	0	0	0	0
Harrington [1]	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days >0.5 dv	13	7	3	6	10
			Days >1.0 dv	5	1	1	4	4
		WIMO	Max dv	4.928	4.362	3.798	0.565	1.130
			Days >0.5 dv	15	11	6	4	9
			Days >1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days >0.5 dv	5	1	1	4	4
			Days >1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.708	2.382	2.065	0.326	0.643
			Days >0.5 dv	6	5	4	1	2
			Days >1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days >0.5 dv	5	1	1	4	4
			Days >1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.770	2.407	2.046	0.363	0.723
			Days >0.5 dv	6	5	4	1	2
			Days >1.0 dv	4	1	1	3	3

[103] 40 CFR 51 Appendix Y, IV.D.5: ''Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions.''

TABLE 15—VISIBILITY BENEFIT OF RETROFIT CONTROLS: COAL-FIRED UNITS (CAMX MODELING)—Continued

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
J T Deely	Source (Sommers 1&2, J T Deely 1&2).	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days >0.5 dv	47	8	1	39	46
			Days >1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days >0.5 dv	7	3	2	4	5
			Days >1.0 dv	2	1	0	1	2
	J T Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days >0.5 dv	4	0	0	4	4
			Days >1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days >0.5 dv	2	0	0	2	2
			Days >1.0 dv	0	0	0	0	0
	J T Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days >0.5 dv	3	0	0	3	3
			Days >1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days >0.5 dv	2	0	0	2	2
			Days >1.0 dv	0	0	0	0	0
W.A. Parish	Source (WAP 4, 5, & 6)	CACR	Max dv	3.177	2.032	0.511	1.145	2.665
			Days >0.5 dv	54	26	1	28	53
			Days >1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days >0.5 dv	34	14	0	20	34
			Days >1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518
			Days >0.5 dv	22	9	0	13	22
			Days >1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days >0.5 dv	11	1	0	10	11
			Days >1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days >0.5 dv	22	8	0	14	22
			Days >1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days >0.5 dv	9	1	0	8	9
			Days >1.0 dv	1	0	0	1	1
Welsh [2]	Source (Unit 1 & 2)	CACR	Max dv	4.576		0.822		3.754
			Days >0.5 dv	92		3		89
			Days >1.0 dv	39		0		39
		MING	Max dv	2.544		0.570		1.973
			Days >0.5 dv	9		1		8
			Days >1.0 dv	3		0		3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days >0.5 dv	37	18	3	19	34
			Days >1.0 dv	8	3	0	5	8
		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days >0.5 dv	2	1	1	1	1
			Days >1.0 dv	1	0	0	1	1
Fayette [2]	Source (Unit 1 & 2)	CACR	Max dv	1.894		0.903		0.991
			Days >0.5 dv	26		2		24
			Days >1.0 dv	9		0		9
		WIMO	Max dv	1.175		0.580		0.595
			Days >0.5 dv	19		1		18
			Days >1.0 dv	2		0		2
	Unit 1	CACR	Max dv	1.002		0.480		0.522
			Days >0.5 dv	9		0		9
			Days >1.0 dv	1		0		1
		WIMO	Max dv	0.609		0.306		0.302
			Days >0.5 dv	2		0		2
			Days >1.0 dv	0		0		0
	Unit 2	CACR	Max dv	0.974		0.441		0.534
			Days >0.5 dv	9		0		9
			Days >1.0 dv	0		0		0
		WIMO	Max dv	0.598		0.282		0.316
			Days >0.5 dv	2		0		2
			Days >1.0 dv	0		0		0

[1] Harrington high control scenario for both units is SDA at 95% reduction.

[2] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD (wet FGD) installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.

TABLE 16—VISIBILITY BENEFIT OF RETROFIT CONTROLS: COAL-FIRED UNITS (CALPUFF MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2).	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days >0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days >1.0 dv Avg.	42.00	21.00	1.00	21	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days >0.5 dv Avg.	91.67	64.33	4.67	27.33	87.00
			Days >1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello[1]	Source (Unit 1, 2 and 3).	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days >0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days >1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU[4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days >0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days >1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days >0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days >1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington[2]	Source (Units 061B & 062B).	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days >0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days >1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days >0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33
			Days >1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh[3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days >0.5 dv Avg.	50.33	32.67	12.33	17.67	38
			Days >1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days >0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days >1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days >0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days >1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction.
[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

b. Visibility Benefits of Scrubber Upgrades for Coal-Fired Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

TABLE 17—VISIBILITY BENEFIT OF SCRUBBER UPGRADES: COAL-FIRED UNITS (CAMX MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	(90%) control	(95%) control	(90%) benefit	(95%) benefit
Martin Lake	Source (Unit 1, 2 & 3).	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days >0.5 dv	141	75	56	66	85
			Days >1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days >0.5 dv	99	39	22	60	77
			Days >1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days >0.5 dv	71	17	6	54	65
			Days >1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days >0.5 dv	44	6	3	38	41
			Days >1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655
			Days >0.5 dv	68	18	9	50	59
			Days >1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days >0.5 dv	40	6	5	34	35
			Days >1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days >0.5 dv	76	15	6	61	70
			Days >1.0 dv	29	2	1	27	28
		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478
			Days >0.5 dv	46	6	4	40	42

TABLE 17—VISIBILITY BENEFIT OF SCRUBBER UPGRADES: COAL-FIRED UNITS (CAMX MODELING)—Continued

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	(90%) control	(95%) control	(90%) benefit	(95%) benefit
			Days >1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1, 2 and 3).	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days >0.5 dv	152	107	28	45	124
			Days >1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days >0.5 dv	67	35	4	32	63
			Days >1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719
			Days >0.5 dv	79	5	5	74	74
			Days >1.0 dv	32	0	0	32	32
		WIMO	Max dv	2.282	0.462	0.364	1.820	1.918
			Days >0.5 dv	31	0	0	31	31
			Days >1.0 dv	7	0	0	7	7

TABLE 18—VISIBILITY BENEFIT OF SCRUBBER UPGRADES: COAL-FIRED UNITS (CALPUFF MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3).	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days >0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days >1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days >0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days >1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1, 2 and 3).	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days >0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days >1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days >0.5 dv Avg.	103	61	13.67	42	89.33
			Days >1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days >0.5 dv Avg.	60	34.67	6	25.33	54
			Days >1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

c. Visibility Benefits of Fuel Oil Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits.

TABLE 19—VISIBILITY BENEFITS FROM LOWER SULFUR FUEL

Facility name	Emission unit	Baseline visibility impact from source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
Stryker	ST2	CALPUFF 0.65% S: 0.786 dv @ CACR (Facility).	CALPUFF (0.3% S): 0.263 dv @ CACR (Facility).	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69% S: 1.228 dv @ WIMO (Facility).	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility.	CALPUFF: 0.851 dv @ WIMO (Facility)
Wilkes	Units 1, 2, 3	CALPUFF 0.43% S: 0.698 dv @ CACR (Facility).	CALPUFF (0.1% S): 0.029 dv @ CACR (Facility).	CALPUFF: 0.037 dv @ CACR (Facility)
Newman [1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A
Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit).	0.004 dv @ CACR	0.008 dv @ CACR

TABLE 19—VISIBILITY BENEFITS FROM LOWER SULFUR FUEL—Continued

Facility name	Emission unit	Baseline visibility impact from source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit).	0.023 @ CACR	0.047 @ CACR

[1] Newman is on the edge of the CALMET and CALPUFF modeling grids for the database that were used in this action. Since the facility was near the edge, emissions of the facility's impacts could not be adequately modeled since some of the plumes could have gone out of the grid and not be adequately assessed if they come back into the grid and transport to impact a Class I area.

6. BART Analysis for PM

In our recent Texas-Oklahoma FIP, we initially proposed to approve Texas' determination that no PM BART controls were appropriate for its EGUs, based on a screening analysis of the visibility impacts from just PM emissions and the premise that EGU SO_2 and NO_X were covered separately by participation in CSAPR (allowing consideration of PM emissions in isolation). Because of the CSAPR remand and resulting uncertainty regarding SO_2 and NO_X BART for EGUs, we decided not to finalize our proposed approval of Texas' PM BART determination.[104] For reasons earlier stated we are proposing to disapprove the SIP determination regarding PM BART for EGUs. Following from that proposed disapproval, we are proposing a PM BART FIP for those Texas EGUs that are subject to BART.

The BART Guidelines permit us to conduct a streamlined analysis of PM BART in two key ways. First, the Guidelines allow a streamlined analysis for PM sources subject to MACT standards. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, the Guidelines state it is permissible to rely on MACT standards for purposes of BART.[105]

Second, with respect to gas-fired units, which have inherently low emissions of PM (as well as SO_2), the Regional Haze Rule did not specifically envision new or additional controls or emissions reductions from the PM BART requirement. The BART guidelines preclude us from stating that PM emissions are *de minimis* when plant-wide emissions exceed 15 tons per years. While we must assign PM BART determinations to the gas-firing units, there are no practical add-on controls to consider for setting a more stringent PM BART emissions limit. The Guidelines state that if the most stringent controls are made federally enforceable for BART, then the otherwise required analyses leading up to the BART determination can be skipped.[106]

With this background, we are providing our evaluation along with some supplementary information on the BART sources as divided into two categories: coal-fired EGUs, and gas-fired EGUs.

BART Analysis for PM for Coal-Fired Units

All of the coal-fired EGUs that are subject to BART are currently equipped with either Electrostatic Precipitators (ESPs) or baghouses, or both, as can be seen from Table 20:

TABLE 20—CURRENT PM CONTROLS FOR COAL-FIRED UNITS SUBJECT TO BART

Facility name	Unit ID	Fuel type (primary)	SO_2 control(s)	PM control(s)
Big Brown	1	Coal		Baghouse + Electrostatic Precipitator.
Big Brown	2	Coal		Baghouse + Electrostatic Precipitator.
Coleto Creek	1	Coal		Baghouse.
Harrington Station	061B	Coal		Electrostatic Precipitator.
Harrington Station	062B	Coal		Baghouse.
J T Deely	1	Coal		Baghouse.
J T Deely	2	Coal		Baghouse.
Martin Lake	1	Coal	Wet Limestone	Electrostatic Precipitator.
Martin Lake	2	Coal	Wet Limestone	Electrostatic Precipitator.
Martin Lake	3	Coal	Wet Limestone	Electrostatic Precipitator.
Monticello	1	Coal		Baghouse + Electrostatic Precipitator.
Monticello	2	Coal		Baghouse + Electrostatic Precipitator.
Monticello	3	Coal	Wet Limestone	Electrostatic Precipitator.
Fayette	1	Coal	Wet Limestone	Electrostatic Precipitator.
Fayette	2	Coal	Wet Limestone	Electrostatic Precipitator.
W A Parish	WAP5	Coal		Baghouse.
W A Parish	WAP6	Coal		Baghouse.
Welsh Power Plant	1	Coal		Baghouse (Began Nov 15, 2015) + Electrostatic Precipitator.

As an initial matter, we examine the control efficiencies of both baghouses and ESPs. We consider a baghouse, widely reported to be capable of 99.9% control of PM, to be the maximum level control for PM and so the units equipped with a baghouse will not be further analyzed for PM BART. The remaining units are fitted with ESPs.

The particulate matter control efficiency of ESPs varies somewhat with

[104] 81 FR 302 (January 5, 2016).

[105] 70 FR 39163–39164.

[106] 70 FR 39165 (''. . . you may skip the remaining analyses in this section, including the visibility analysis . . .'')

the design, the resistivity of the particulate matter, and the maintenance of the ESP. We do not have any information on the control level efficiency of any of the ESPs for the units in question. However, reported control efficiencies for well-maintained ESPs typically range from greater than 99% to 99.9%.[107] We consider this pertinent in concluding that the potential additional particulate control that a baghouse can offer over an ESP is relatively minimal.[108] In other words, if we did obtain control information specific to the ESP units in question, we do not believe that additional information would lead us to a different conclusion.

Nevertheless, w'e will examine the potential cost of retrofitting a typical 500 MW coal fired unit with a baghouse. Using our baghouse cost algorithms, as employed in version 5.13 of our IPM model,[109] and assuming a conservative air to cloth ratio of 6.0, results in a capital engineering and construction cost of $77,428,000.[110] Applied to the subject units, this cost assumes a retrofit factor of 1.0, and does not consider the demolition of the existing ESP, should it be required in order to make space for the baghouse.

We do not calculate the cost-effectiveness resulting from replacing an ESP with a baghouse. However, we expect that the tons of additional PM removed by a baghouse over an ESP to be very small, which would result in a very high cost-effectiveness figure. Also, we do not model the visibility benefit of replacing an ESP with a baghouse. However, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from replacing an ESP with a baghouse to be a small fraction of that. For instance, our CAMx baseline modeling shows that on a source-wide level, impacts from PM emissions on the maximum impacted days from each source at each Class I area was 3% of the total visibility impairment or less (calculated as percent of total extinction due to the source). Therefore additional PM controls are anticipated to result in very little visibility benefit on the maximum impacted days. Similarly, our CALPUFF modeling indicates that visibility impairment from PM is also a small fraction (typically only a few percent) of the total visibility impairment due to each source.

Adding to the above discussion, we are tasked to assign the enforceable emission limitations that constitute PM BART. We believe a stringent control level that would be met with existing or otherwise-required controls is a filterable PM limit of 0.03 lb/MMBtu for each of the coal-fired units subject to BART. We note that the Mercury and Air Toxics (MATS) Rule establishes an emission standard of 0.03 lb/MMBtu filterable PM (as a surrogate for toxic non-mercury metals) as representing Maximum Achievable Control Technology (MACT) for coal-fired EGUs.[111] This standard derives from the average emission limitation achieved by the best performing 12 percent of existing coal-fired EGUs, as based upon test data used in developing the MATS Rule. We are not familiar with any new technologies subsequent to this standard that could lead to any cost effective increases in the level of control; thus, consistent with the BART Guidelines, we are proposing to rely on this limit for purposes of PM BART for all of the coal-fired units as part of our FIP. We understand the coal-fired units covered by this proposal to be subject to MATS, but to the extent the units may be following alternate limits that differ from the surrogate PM limits found in MATS, we welcome comments on different, appropriately stringent limits reflective of current control capabilities.[112] Because we anticipate that any limit we assign should be achieved by current control capabilities, we propose that compliance can be met at the effective date of the rule. To address periods of startups and shutdowns, we are further proposing that PM BART for these units will additionally be met by following the work practice standards specified in 40 CFR part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042. We are proposing that the demonstration of compliance can be satisfied by the methods for demonstrating compliance with filterable PM limits that are specified in 40 CFR part 63, subpart UUUUU, Table 7. However, we would give consideration to commenter-submitted requests for alternate or additional methods of demonstrating compliance.

BART Analysis for PM for Gas-Fired Units

We note that PM emissions for the gas-only fired units that are subject to BART are inherently low.[113] We therefore conclude that PM emissions from natural gas firing is so minimal that the installation of any additional PM controls on the unit would likely achieve very low emissions reductions and have minimal visibility benefits. As there are no appropriate add-on controls and the status quo reflects the most stringent controls, we are proposing to make the requirement to burn pipeline natural gas federally enforceable. We note that in addition to satisfying PM BART, this limitation will also serve to satisfy SO_2 BART for these gas-fired units, as well as the fuel-oil units when they fire natural gas. We are proposing that PM and SO_2 BART for gas fired-units will limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

The available PM controls for gas units that also burn fuel oil are the same for the coal-fired units. We would expect similar costs for installing a baghouse on a typical gas-fired boiler that occasionally burns fuel oil. Again, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from the installation of a baghouse to be a small fraction on the order of 1–3% of the visibility impacts from the facility. We are confident that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. We conclude that the cost of a baghouse does not justify the minimal expected improvement in visibility for these units. Accordingly, we are proposing that the fuel content limits for oil burning that we propose to meet SO_2 BART will also satisfy PM BART.

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[107] EPA, ''Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP)—Wire Plate Type,'' EPA–452/F–03–028. Grieco, G., ''Particulate Matter Control for Coal-fired Generating Units: Separating Perception from Fact,'' *apcmag.net,* February, 2012. Moretti, A. L.; Jones, C. S., ''Advanced Emissions Control Technologies for Coal-Fired Power Plants, Babcox and Wilcox Technical Paper BR–1886, Presented at Power-Gen Asia, Bangkok, Thailand, October 3–5, 2012.

[108] We do not discount the potential health benefits this additional control can have for ambient PM. However, the regional haze program is only concerned with improving the visibility at Class I areas.

[109] IPM Model—Updates to Cost and Performance for APC Technologies, Particulate Control Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5–7: PM Cost Methodology, downloaded from: *https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-7_pm_cost_methodology.pdf.*

[110] *Id.* See page 9.

[111] 77 FR 9304, 9450, 9458 (February 16, 2012) (codified at 40 CFR 60.42 Da(a), 60.50 Da(b)(1)); 40 CFR part 63 Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units.

[112] The various limits are provided at 40 CFR part 63, subpart UUUUU, Table 2 (''Emission Limits for Existing EGUs'').

[113] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: *https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.*

Lastly, should our assumptions regarding the frequency and type of fuel oil burned in these units significantly change, we expect that Texas will address such a change appropriately in its SIP, which we will review in the next planning period.

D. How, if at all, do issues of ''Grid Reliability'' relate to the proposed BART determinations?

On July 15, 2016, a preliminary order of the Fifth Circuit Court of Appeals took the view that EPA's Texas-Oklahoma FIP (81 FR 295, January 5, 2016) gave a ''truncated discussion of grid reliability'' and additionally stated that ''the agency may not have fulfilled its statutory obligation to consider the energy impacts of the FIP.'' The Court's preliminary ruling made particular reference to ''the explicit directive in the [CAA] that implementation plans 'take[ ] into consideration . . . the energy . . . impacts of compliance,' 42 U.S.C. 7491(g)(1).'' [114] Because the BART requirement at issue in this proposal has similar language on *energy impacts of compliance* appearing at 42 U.S.C. 7491(g)(2), we wish to provide a clear explanation on how grid-related considerations for EGUs could bear on this proposal.

First, the BART factor for *energy impacts of compliance* does not call for the examination of grid reliability considerations from alleged plans to shut down or retire a unit rather than comply with a more stringent emission limit or limits. The language instead calls for consideration of energy impacts from *complying* by installing retrofit controls on a source that continues in operation. In this regard, our proposal follows the required BART Guidelines for EGUs.[115] The Guidelines explain that the energy impacts factor relates to the penalties and benefits that may be associated with the assessment of a control option, *e.g.,* whether (for power penalties) the operation of add-on control technology subtracts from the productive yield of electricity from an EGU (what is sometimes termed an auxiliary or parasitic load).[116] It is also useful to note that the statutory text, while using the word ''energy,'' can apply to sources that do not produce energy or electricity. Thus, the statutory text regarding ''energy impacts'' of compliance with BART is not confined to the power generating industry and does not dictate that we study grid reliability issues.

We have considered whether this topic has any separate relevance to our proposal. Various court filings, news accounts, and industry market reports suggest that some source operators for some Texas BART units may be contemplating unit retirements. The BART Guidelines directly address such scenarios under the ''remaining useful life'' factor: ''there may be situations where a source operator intends to shut down a source . . . . but wishes to retain the flexibility to continue operating beyond that date in the event, for example, the market conditions change.'' [117] The Guidelines advise that a source that is willing to assure a permanent stop in operations with a federally- or State-enforceable restriction preventing further operation may obtain a short remaining useful life for BART analysis purposes that could then factor in the overall cost analysis.[118] As the Guidelines state, ''Where the remaining useful life is less the than the time period for amortizing costs, you should use this shorter period in your cost calculations.'' [119] We have no information on enforceable restrictions of this type for any of the units that we propose to be subject to BART. Absent that, we must assume that controls installed on the BART units will experience their full useful life. Affected sources are free to submit information as part of their comments containing appropriate enforceable documentation of shorter remaining useful lives.

We note, however, that the Guidelines recognize there may be cases where the installation of controls, even when cost-effective, would ''affect the viability of continued plant operations.'' [120] Under the Guidelines, where there are ''unusual circumstances,'' we are permitted to take into consideration ''the conditions of the plant and the economic effects of requiring the use of a control technology.'' [121] If the effects are judged to have a ''severe impact,'' those effects can be considered in the selection process. In such cases, the Guidelines counsel that any determinations be made with an economic analysis with sufficient detail for public review on the ''specific economic effects, parameters, and reasoning.'' [122] It is recognized, by the language of the Guidelines, that any such review process may entail the use of sensitive business information that may be confidential. The **ADDRESSES** section of this proposal explains how to submit confidential information with comments, and when claims of confidential business information, or CBI, are asserted with respect to any information that is submitted, the EPA regulations at 40 CFR part 2, subpart B-Confidentiality Business Information apply to protect it. All of that said, the Guidelines also advise that we may ''consider whether other competing plants in the same industry have been required to install BART controls if this information is available.'' [123] Because Texas EGUs are among the last to have SO_2 BART determinations, this information is available. It is indeed the case that other similar EGUs have been required to install the same types of SO_2 BART controls that we are proposing as very cost effective.[124]

We have considered the state of available information on whether the proposed controls could affect the viability of continued plant operations. On this point, we note that we are proposing BART determinations for several units where SO_2 control requirements were separately promulgated as part of the Texas-Oklahoma FIP. These under-controlled EGU sources are: Big Brown 1 and 2; Monticello 1, 2 and 3; Martin Lake 1, 2 and 3; and Coleto Creek 1. In litigation over the reasonable progress FIP, various declarations were filed on the issues of alleged forced closures and alleged reliability impacts. These declarations have been compiled and added to the docket for this rulemaking.

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[114] EPA Guidance on this statutory language specifically explains that energy impacts are a matter of whether ''energy requirements associated with a control technology result in energy penalties.'' U.S. EPA, Office of Air Quality Planning and Standards, ''Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,'' (June 1, 2007 rev), at Page 5–2.

[115] The promulgation of the Guidelines was required by 42 U.S.C. 7491(b)(1). Adherence to the Guidelines is mandatory for fossil-fuel fired generating power plants having total generating capacities ''in excess of 750 megawatts.''

[116] Other CAA provisions requiring consideration of ''energy impacts'' or ''energy requirements of the control technology'' are understood similarly. *See, e.g.,* CAA section 169 (the 1977 ''best available control technology'' requirement with consideration of ''energy . . . impacts''); *see also* CAA section 108 (''energy requirements . . . of the emission control technology; ''energy . . . impact of such processes, procedures, and methods [to reduce or control air pollution''); section 111 (''taking into account . . . energy requirements'' of an emission limitation), etc.

[117] *Id.* at 39169–39170.

[118] Similar to calculating a mortgage, remaining useful life is used in our cost-effectiveness analysis to calculate the annual cost of a particular control. The longer the remaining useful life, the smaller the total annualized cost, and the more cost-effective the control.

[119] *Id.* at 39169.

[120] 70 FR 39103, 39171 (July 6, 2005), [40 CFR part 51, App. Y].

[121] *Id.*

[122] 70 FR at 39171.

[123] *Id.*

[124] See for instance, the EIA information we present elsewhere in this notice in which we summarize the hundreds of scrubber installations that have been performed on similar EGUs.

By our review, these declarations do not appropriately inform or substantiate source-specific allegations of ''unusual circumstances'' that may have a severe impact on plant operations, because they do not offer any site-specific information.[125] Thus, we are unable to conclude that the proposed cost-effective BART controls would severely impact plant operations. Generalized claims of possible retirements and discussions on attributes of the market design of the Electric Reliability Council of Texas (ERCOT) cannot inform the statutorily required, source-specific BART determinations.

As a predicate to studying effects on transmission or reliability as ''unusual circumstances,'' we would require site-specific information from any source that would wish for us to potentially consider ''affordability of controls,'' under the terms specified in the Guidelines. Source owners may submit information, including information claimed to be CBI, for our assessment and consideration to potentially support an economic analysis that might be used in the BART selection process. As suggested by the Guidelines, the information necessary to inform our judgment would likely entail source-specific information on ''product prices, the market share, and the profitability of the source.'' Consideration of such information does not dictate what will be selected as a ''best'' alternative under the Guidelines, but it will substantiate the likelihood of a retirement scenario that would then give the parameters for: A non-conjectural examination of grid reliability issues; judging the significance or insignificance of such issues; and assessing whether such issues could be avoided through appropriate transmission planning. In sum, unless we are able to substantiate an ''affordability of controls'' problem for any particular unit and substantiate that a particular unit retirement would not be happening anyway at about the same time, alleged grid reliability impacts are speculative and are not able to inform these required BART determinations. As a final note, we acknowledge Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, and Use''). In cases where it does apply, agencies are ordered to prepare a Statement of Energy Effects for submission to the Administrator of the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget. This EGU BART proposal is not considered a significant regulatory action under Executive Order 12866, so the proposed action cannot be a ''significant energy action'' for purposes of Executive Order 13211 on that basis. This proposed action has also not been designated a significant energy action by the Administrator of OIRA, so Executive Order 13211 could not apply under that separate basis. With this proposal, there are no anticipated adverse effects on energy supply, distribution, or use that are meaningful or distinguishable from any other scenario where an EGU is expected to install cost-effective pollution controls required by the CAA.

IV. Our Weighing of the Five BART Factors

Below we present our reasoning for proposing our BART determinations for 29 EGUs in Texas, based on our analysis and weighing of the Five BART Factors: (1) Proposed SO_2 and PM BART determinations for 12 coal-fired units with no SO_2 controls, (2) proposed BART SO_2 and PM BART determinations for 6 coal-fired units with existing scrubbers, (3) proposed SO_2 and PM BART determinations 7 gas-fired units that occasionally burn fuel oil, and (4) proposed PM BART determinations for 4 gas-fired units.

In previous sections of this proposal, we have described how we assessed the five BART factors. In no case do we see any instance in which our assessment of energy impacts is a determining factor in assessing BART.[126] Also, in no case do we see any instance in which our assessment of the remaining useful life is a determining factor in assessing BART. Should a facility indicate in comments to us that the remaining useful life is less than the 30 years we have assumed in our control cost analyses, and is willing to enter into an enforceable document to that effect, we will adjust our cost-effectiveness calculation accordingly in making our final decision. In two cases, Harrington units 061B and 062B, we have limited our SO_2 control analysis for Harrington to DSI and dry scrubbers due to potential non-air quality concerns. In all other instances, we conclude that the cost of compliance, and the visibility benefits of controls are the controlling BART factors in our weighing of the five BART factors.

In considering cost-effectiveness and visibility benefit, we do not eliminate any controls based solely on the magnitude of the cost-effectiveness value, nor do we use cost-effectiveness as the primary determining factor. Rather, we compare the cost-effectiveness to the anticipated visibility benefit, and we take note of any additional considerations.[127] Also, in judging the visibility benefit we do not simply examine the highest value for a given Class I area, or a group of Class I areas, but we also consider the cumulative visibility benefit for all affected Class I areas, the number of days in a calendar year in which we see significant improvements, and other factors.[128]

First, we note that all of the sources addressed in our proposed BART determinations have already been shown to cause or contribute to visibility impairment at a Class I area as a condition of being subject-to-BART as part of the BART screening analysis. This analysis eliminated any BART-eligible source that emits lower amounts of visibility impacting pollutants, or otherwise impacts any Class I area at less than 0.5 deciviews. In fact, all of the individual units that we are proposing for BART controls exceed 0.5 deciviews on a unit basis, with most exceeding 1.0 deciview impact on a unit basis. As a consequence, all of the units we are proposing for BART controls are among the largest emitters of visibility impacting pollutants in Texas. A number of these units (*i.e.,* Big Brown, Martin Lake, Monticello, and Coleto Creek) were previously determined by us to require the same type and level of controls under the reasonable progress and long-term strategy provisions of the Regional Haze Rule that we are proposing here.[129]

Second, not discounting our approach of considering both cost-effectiveness and visibility benefit in unison, the cost-effectiveness of all of the controls that form the basis of our proposed BART determinations are within a range found to be acceptable in other cases.[130] As we

[125] Certain statements in declarations from representatives of both Luminant and Coleto Creek, who are the source owners of these facilities, cited compliance planning efforts that would be consistent with continued plant operations.

[126] In addition to our assessment of energy impacts, also see our discussion in Section III.D concerning our conclusion that energy impact considerations do not relate to potential electrical grid reliability issues.

[127] For instance, as we discuss later in Section IV.C why we believe that there are certain mitigating factors that should be considered when assessing BART for the gas-fired units that occasionally burn fuel oil.

[128] See for example 70 39130: ''comparison thresholds can be used in a number of ways in evaluating visibility improvement (*e.g.* the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, a threshold representing an x percent change in improvement, etc.).''

[129] See our recent Texas-Oklahoma FIP, 81 FR 321.

[130] See for instance 79 FR 5048 (January 30, 2014): Jim Bridger BART determination of LNB/SOFA + SCR on Units 1–4; 77 FR 18070 (March 26, 2012): EPA proposed approval of Colorado's BART

stated in the BART Rule, ''[a] reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time.'' [131]

A. SO_2 BART for Coal-fired Units With No SO_2 Controls

As we have discussed in this proposal and in our TSD, we have assumed two DSI control levels corresponding to 50% control and either a maximum of 80% or 90% control, depending on the particulate matter control device in use.[132] We did this to address the BART Guidelines directive that in evaluating technically feasible alternatives we ''(1) [ensure we] express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options, and (2) [give] appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.'' [133] In most cases, the cost-effectiveness of the higher control level of DSI was higher than either SDA or wet FGD. This was not the case for Monticello Unit 2; Harrington Unit 062B; and J T Deely Units 1 and 2.

However, these maximum DSI control levels are theoretical and we believe that any DSI control level above 50% must be confirmed by onsite testing before we could propose a BART control based on it. As is evident in comparing the 50% control level to the higher control level, the cost-effectiveness of DSI worsens (higher $/ton) as the control level increases, and the certainty of any unit attaining that control level decreases. We therefore regard the cost-effectiveness values of the maximum DSI control levels as being useful in a basic comparison of cost-effectiveness between DSI and scrubbers, but we place much less weight on these values. We therefore conclude that given the uncertainty concerning the maximum control level of DSI, the greater control efficiency and resulting visibility benefit offered by scrubbers overrides any possible advantage DSI may hold in cost-effectiveness. Should the affected facilities provide site-specific information to us in their comments that conflicts with this assumption, we will incorporate it into our final decision on SO_2 BART and potentially re-evaluate DSI.

As we indicate elsewhere in our proposal, both SDA and wet FGD are mature technologies that are in wide use throughout the United States. We are not aware of any unusual circumstances that exist for any of the sources that would serve to indicate they should not be viewed similarly to these hundreds of previous scrubber retrofits. In comparing wet FGD versus SDA we note that in a number of cases the cost-effectiveness of wet FGD is lower than the cost-effectiveness of SDA. In the remaining cases, we conclude that the incremental cost-effectiveness of wet FGD over SDA, which we review in Section III.C.3.a is reasonable, and the improved control and visibility benefit offered by wet FGD overrides the small penalty in cost-effectiveness FGD has in comparison to SDA. We propose that with the exception of the Harrington units, SO_2 BART for all other coal-fired units should be based on the wet FGD control levels we have used in our BART analyses. We propose that SO_2 BART for the Harrington units should be based on the SDA control levels we have used in our BART analyses. Below we discuss our consideration of the cost-effectiveness and anticipated visibility benefits of controls. See section III.C.5 for additional information on the anticipated visibility benefits from each level of control modeled. See the BART Modeling TSD for a complete summary of our visibility benefit analysis of controls, including modeled benefits and impacts at all Class I areas included in the modeling analyses and additional metrics considered in the assessment of visibility benefits.

CAMx model results shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. The benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario. Also summarized are the cumulative benefit and the number of days impacted over 0.5 and 1.0 dv. Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario summed across the 15 Class I areas included in the CAMx modeling. The baseline total cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold in the baseline modeling. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario. The CALPUFF cumulative model results only consider those Class I areas within the typical range of CALPUFF and not all 15 Class I areas included in the CAMx modeling.

1. Big Brown 1 & 2

In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 21—WET FGD VISIBILITY BENEFITS AT BIG BROWN (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv) [1]	Cumulative reduction in number of days above 0.5 dv [2]	Cumulative reduction in number of days above 1.0 dv [2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains.

[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

determination of SCR for Hayden Unit 2, later finalized at 77 FR 76871 (December 31, 2012).

[131] 70 FR 39168 (July 6, 2005).

[132] Note for Harrington Unit 062B and Welsh 1, we further limited the maximum DSI control level to that of our calculated SDA control level.

[133] 70 FR 39166 (July 6, 2005).

In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis.

TABLE 22—WET FGD VISIBILITY BENEFITS AT BIG BROWN (CAMX)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv)[1]	Baseline total cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174/44	174/44
Big Brown 2	1.940	1.642	12.924	175/45	175/45
Source	3.542	2.988	24.274	372/170	362/170

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.
[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD will on each unit result in visibility improvements of 1.9 dv on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the CAMx modeling.

We also conclude that wet FGD is very cost-effective for both units at less than $1,200/ton and more cost-effective than DSI. Based on this consideration of the BART factors, we propose that SO_2 BART for Big Brown Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

2. Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 23—WET FGD VISIBILITY BENEFITS AT MONTICELLO (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total cumulative visibility benefit (dv)[1]	Baseline total cumulative number of days over 0.5/1.0 dv[2]	Cumulative reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6

days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I area and half of the cumulative benefits.

TABLE 24—WET FGD VISIBILITY BENEFITS AT MONTICELLO (CAMX)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Monticello 1	3.783	1.989	12.708	197/67	191/67
Monticello 2	3.924	2.003	13.025	192/57	191/57
Source (including unit 3)	8.419	4.962	31.553	520/293	460/278

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.
[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1 dv at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8–3.9 dv on the most impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

The wet FGD cost-effectiveness of $2,718/ton and $3,031/ton are higher than those for Big Brown, but these figures remain well within a range that we have previously found to be acceptable for BART, and we consider the very significant visibility benefits that will result justify the cost of wet FGD at the Monticello Units 1 and 2. The 50% control DSI cost-effectiveness is slightly less than that for wet-FGD, but results in much less visibility benefits. Based on our consideration of the BART factors, we therefore propose that SO_2 BART for Monticello Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

3. Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

TABLE 25—WET FGD VISIBILITY BENEFITS AT COLETO CREEK UNIT 1 (CAMX)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Coleto Creek 1	0.668	0.606	5.233	17/0	17/0

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.
[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling.

We also conclude that wet FGD is very cost-effective at $2,127/ton and well within a range that we have previously found to be acceptable and more cost-effective than DSI. We consider the significant visibility benefits that will result justify the cost of wet FGD at the Coleto Creek Unit 1. We therefore propose that SO_2 BART for Coleto Creek Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

4. Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 26—WET FGD VISIBILITY BENEFITS AT WELSH UNIT 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total cumulative visibility benefit (dv) [1]	Cumulative reduction in number of days above 0.5 dv [2]	Cumulative reduction in number of days above 1.0 dv [2]
Welsh 1	0.72	0.41	1.66	56.67	15

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.

[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

TABLE 27—WET FGD VISIBILITY BENEFITS AT WELSH UNIT 1 (CAMX)

Unit	Improvement at Caney Creek (dv)	Improvement at Mingo Wilderness (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Welsh 1	1.521	0.579	4.683	65/9	60/9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211/72	206/72

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.

[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.

[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We conclude that although at $3,824/ton, the cost-effectiveness of wet FGD is higher than for other facilities, it remains within a range that we have previously found to be acceptable. We consider the significant visibility benefits that will result from the installation of wet FGD at Welsh Unit 1 to justify the cost. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for Welsh Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

5. Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 28—SDA VISIBILITY BENEFITS AT HARRINGTON (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total cumulative visibility benefit (dv) [1]	Cumulative reduction in number of days above 0.5 dv [2]	Cumulative reduction in number of days above 1.0 dv [2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

TABLE 29—SDA VISIBILITY BENEFITS AT HARRINGTON (CAMX)

Unit	Improvement at Salt Creek (dv)	Improvement at Wichita Mountains (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Harrington 061B	1.170	0.643	4.832	17/5	11/3
Harrington 062B	1.279	0.723	5.379	17/5	11/3
Source (061B & 0622B)	2.053	1.130	9.329	51/17	37/11

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.

[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.

[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6–0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We also conclude that SDA is cost-effective at $3,904 for Unit 061B and $4,180/ton for Unit 062B and, remains within a range that we have previously found to be acceptable. In contrast to other units we have reviewed, the 50% control DSI cost-effectiveness is much less than that for SDA. However, given the additional large total cumulative visibility benefits that will result from the installation of SDA over DSI at 50% control, we consider SDA to justify the additional cost. We therefore propose that SO_2 BART for Harrington Units 061B and 062B should be based on the installation of SDA at an emission limit of 0.06 lbs/MMBtu based on a 30 BOD.

6. W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 30—WET FGD VISIBILITY BENEFITS AT W A PARISH (CAMX)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
W A Parish 5	1.518	0.943	8.171	51/9	51/9
W A Parish 6	1.492	0.922	7.979	48/7	48/7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163/49	162/49

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.
[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5 dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios.

We conclude that wet FGD is cost-effective at $2,417/ton for Unit 5 and $2,259/ton for Unit 6, and remains well within a range that we have previously found to be acceptable. DSI at 50% control is approximately the same cost-effectiveness but results in significantly less visibility benefit. We consider the cost of wet FGD at the W A Parish units to be justified by the significant visibility benefits that will result. We therefore propose that SO_2 BART for W A Parish Units 5 and 6 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

7. J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 31—WET FGD VISIBILITY BENEFITS AT J T DEELY (CAMX)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
J T Deely 1	0.487	0.283	4.785	10/0	10/0
J T Deely 2	0.298	0.217	3.650	7/0	7/0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89/13	84/13

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] Baseline Total Cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold.
[3] Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas. Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and as discussed in the BART Modeling TSD, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source.

We conclude that wet FGD is cost-effective at $3,898/ton for Unit 1 and $3,712/ton for Unit 2, and remains within a range that we have previously found to be acceptable. We consider the cost of wet FGD at the J T Deely units to be justified by the significant visibility benefits that will result at a number of impacted Class I areas. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for J T Deely Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.[134]

B. SO_2 BART for Coal-fired Units With Underperforming Scrubbers

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[135] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 17 above. The following is a listing of each of the affected units along with the resulting CAMx modeled visibility benefits from upgrading their existing scrubbers:

TABLE 32—VISIBILITY BENEFIT FOR COAL-FIRED UNITS WITH EXISTING SO_2 CONTROLS (CAMX)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total cumulative visibility benefit (dv)	Reduction in number of days above 0.5 dv at——	Reduction in number of days above 1.0 dv at——
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200/66	188/66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160/41	151/40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150/41	134/39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173/47	163/46

As we state elsewhere in this proposal, because our cost-effectiveness calculations depend on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We conclude that in all cases, scrubber upgrades are very cost-effective and result in very significant visibility benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. We propose that SO_2 BART for all other coal-fired units with underperforming scrubbers should be based on the wet FGD upgrade control levels we have used in our BART analyses of them.

C. SO_2 BART for Gas-Fired Units That Burn Oil

In analyzing potential controls for those gas-fired units that occasionally burn fuel oil we considered scrubber retrofits and lower sulfur fuel oil. We concluded that the cost-effectiveness of scrubber retrofits for these units were likely very high, and not worth the potential visibility benefit.

We also concluded that the cost-effectiveness of switching to a No. 2 fuel oil with a sulfur content of 0.3% is $11,218/gallon, and the cost-effectiveness of switching to ULSD with a sulfur content of 0.0015% is $8,627/gallon. We further noted that one facility already had a contract in place for ULSD at a lower price than we assumed, which if used in our analysis would result in a cost effectiveness of $3,970/ton. Although the cost-effectiveness of switching to a lower sulfur oil (assuming our price for ULSD of $1.667/gal) is higher than other controls that we have typically required under BART, we note certain mitigating factors.

For instance, arguing against control, our calculated cost-effectiveness values are high in relation to other BART controls we have required in the past. Also, our visibility modeling necessarily utilized the maximum SO_2 emissions over a 24-hour timeframe,[136] resulting in the configuring of our visibility modeling to analyze the maximum short-term potential impacts that could occur when the unit burns fuel oil. However, as we discuss elsewhere in our proposal, these units are primarily gas-fired, and have only occasionally burned fuel oil. Their most recent practices appear to reinforce this trend.

Arguing for control, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. This means the overall annual costs are relatively minor, if the units in question adhere to their historical usages. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying solely on their primary fuel of natural gas. Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[137]

The preamble to the Regional Haze Rule counseled that a one percent sulfur content limitation on fuel oil should be considered as a ''starting point,'' [138] and the existing sulfur content limits are lower than one percent. Considering all of this information, we propose that SO_2 BART for the gas-fired units that occasionally burn fuel oil should be no further control. In so doing, we acknowledge the data quality issues we have discussed concerning these units and we specifically request comments on all aspects of our proposed BART analysis for these units from all interested parties. Based on the comments we receive, we may either finalize our BART determinations for these units as proposed, or we may revise them without a re-proposal.

D. PM BART

We propose to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We note that all of the coal-fired units are either currently fitted with a baghouse, an ESP and a polishing baghouse, or an ESP. We conclude that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP.

[134] We have read reports that CPS Energy, is planning to retire J T Deely Units 1 and 2 by the end of 2018, but we have no enforceable documents to that effect.

[135] 70 FR 39171 (July 6, 2005).

[136] See the BART Guidelines at 70 FR 39162, July 6, 2005: ''We recommend that States use the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods start-up, shutdown, or malfunction.''

[137] *http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/.*

[138] 70 FR at 39134.

Consequently, we propose that PM BART for the coal-fired units is an emission limit of 0.030 lb/MMBtu along with work practice standards. We propose that PM and SO_2 BART for the units that only fire gas be pipeline natural gas. We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight or pipeline natural gas.

V. Proposed Actions

A. Regional Haze

We are proposing to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We are proposing to promulgate a FIP as described in this notice and summarized in this section to satisfy the remaining outstanding regional haze requirements that are unmet by the Texas' regional haze SIP and that we did not take action on in our January 5, 2016 final action.[139] Our proposed FIP includes SO_2 and PM BART emission limits for sources in Texas to reduce emissions that contribute to regional haze in Texas' two Class I areas and other nearby Class I areas and make reasonable progress for the first regional haze planning period for Texas' two Class I areas.

1. NO_X BART

As discussed elsewhere in this proposal, we are proposing a FIP to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. This portion of our proposal is based on: The recent update to the CSAPR rule;[140] and the EPA's finalization of a separate proposed finding that the EPA's actions in response to the D.C. Circuit's remand would not adversely impact our 2012 demonstration that CSAPR is better than BART.[141] We cannot finalize this portion of the proposed FIP unless and until the EPA finalizes the proposed finding that CSAPR continues to be better than BART because finalization of that proposal would allow for reliance on CSAPR participation as an alternative to source-specific EGU BART for NO_X in Texas.

2. SO_2 BART for Coal-Fired Units

We propose that SO_2 BART for the coal-fired units be the following SO_2 emission limits to be met on a 30 Boiler Operating Day (BOD) period:

TABLE 33—PROPOSED SO_2 BART EMISSIONS LIMITS FOR COAL-FIRED UNITS

Unit	Proposed SO_2 emission limit (lbs/MMBtu)
Scrubber Upgrades	
Martin Lake 1	0.12
Martin Lake 2	0.12
Martin Lake 3	0.11
Monticello 3	0.05
Scrubber Retrofits	
Big Brown 1	0.04
Big Brown 2	0.04
Monticello 1	0.04
Monticello 2	0.04
Coleto Creek 1	0.04
Fayette 1	0.04
Fayette 2	0.04
Harrington 061B	0.06
Harrington 062B	0.06
J T Deely 1	0.04
J T Deely 2	0.04
W A Parish 5	0.04
W A Parish 6	0.04
Welsh 1	0.04

We propose that compliance with these limits be within five years of the effective date of our final rule for Big Brown Units 1 and 2; Monticello Units 1 and 2; Coleto Creek Unit 1; Harrington Units 061B and 062B; J T Deely Units 1 and 2; W A Parish Units 5 and 6; and Welsh Unit 1. This is the maximum amount of time allowed under the Regional Haze Rule for BART compliance. We based our cost analysis on the installation of wet FGD and SDA scrubbers for these units, and in the past we have typically required that scrubber retrofits under BART be operational within five years.

We propose that compliance with these limits be within three years of the effective date of our final rule for Martin Lake Units 1, 2, and 3; and Monticello Unit 3. We believe that three years is appropriate for these units, as we based our cost analysis on upgrading the existing wet FGD scrubbers of these units, which we believe to be less complex and time consuming that the construction of a new scrubber.

We propose that compliance with these limits be within one year for Fayette Units 1 and 2. We believe that one year is appropriate for these units because the Fayette units have already demonstrated their ability to meet these emission limits.

3. Potential Process for Alternative Scrubber Upgrade Emission Limits

In our BART FIP TSD, we discuss how we calculated the SO_2 removal efficiency of the units we analyzed for scrubber upgrades. We note that due to a number of factors we could not accurately quantify, our calculations of scrubber efficiency may contain some error. Based on the results of our scrubber upgrade cost analysis, we do not believe that any reasonable error in calculating the true tons of SO_2 removed affects our proposed decision to require emission reductions, as all of the scrubber upgrades we analyzed are cost-effective (low $/ton). In other words, were we to make reasonable adjustments in the tons removed to account for any potential error in our scrubber efficiency calculation, we would still propose to upgrade these SO_2 scrubbers. We believe we have demonstrated that upgrading an underperforming SO_2 scrubber is one of the most cost-effective pollution control upgrades a coal fired power plant can implement to improve the visibility at Class I areas. However, our proposed FIP does specify a SO_2 emission limit that is based on 95% removal in all cases. This is below the upper end of what an upgraded wet SO_2 scrubber can achieve, which is 98–99%, as we have noted in our BART FIP TSD. We believe that a 95% control assumption provides an adequate margin of error for any of the units for which we have proposed scrubber upgrades, such that they should be able to comfortably attain the emission limits we have proposed. However, for the operator of any unit that disagrees with us on this point, we propose the following:

(1) The affected unit should comment why it believes it cannot attain the SO_2 emission limit we have proposed, based on a scrubber upgrade that includes the kinds of improvements (*e.g.,* elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically included in a scrubber upgrade.

(2) After considering those comments, and responding to all relevant comments in a final rulemaking action, should we still require a scrubber upgrade in our final FIP we will provide the company the following option in the FIP to seek a revised emission limit after taking the following steps:

(a) Install a CEMS at the inlet to the scrubber.

(b) Pre-approval of a scrubber upgrade plan conducted by a third party engineering firm that considers the kinds of improvements (*e.g.,* elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically performed during a scrubber upgrade. The goal of this plan will be to maximize the unit's overall SO_2 removal efficiency.

[139] 81 FR 296.

[140] 81 FR 74504.

[141] 81 FR 78954.

(c) Installation of the scrubber upgrades.

(d) Pre-approval of a performance testing plan, followed by the performance testing itself.

(e) A pre-approved schedule for 2.a through 2.d.

(f) Should we determine that a revision of the SO_2 emission limit is appropriate, we will have to propose a modification to the BART FIP after it has been promulgated. It should be noted that any proposal to modify the SO_2 emission limit will be based largely on the performance testing and may result in a proposed increase or decrease of that value.

4. SO_2 BART for Gas-fired Units That Burn Oil

We propose that SO_2 BART for the following gas-fired units that occasionally burn fuel oil be the existing permit limits for the sulfur content of the fuel oil:

TABLE 34—PROPOSED BART SO_2 EMISSION LIMITS GAS UNITS THAT OCCASIONALLY BURN OIL

Facility	Fuel Oil Sulfur Content (percent by weight)
Graham 2	0.7
Newman 2*	0.7
Newman 3*	0.7
O W Sommers 1	0.7
O W Sommers 2	0.7
Stryker Creek ST2	0.7
Wilkes 1	0.7

*The Newman Units 2 and 3 are further limited to burning fuel oil for no more than 876 hours per year.

5. PM BART

We propose that PM BART limits for the coal units, Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2 are 0.030 lb/MMBtu and work practice standards, which we present below:

TABLE 35—PM BART EMISSIONS STANDARDS AND WORK PRACTICE STANDARDS

Unit Type	PM BART Proposal
Coal-Fired BART Units	0.03 lb/MMBtu filterable PM Table 3 to Subpart UUUUU
Gas-Fired Only BART Units	Pipeline quality natural gas
Oil-Fired BART Units when not firing natural gas	Fuel Content not to exceed 0.7% sulfur by weight (also SO_2 BART)

We propose that compliance with these emissions standards and work practice standards be the effective date of our final rule, as the affected facilities' should already be meeting them.

We propose that PM and SO_2 BART for the units that only fire gas, Newman Unit 4; W A Parish Unit 4; and Wilkes Units 2 and 3 be pipeline natural gas.

We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil, Newman Unit 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes Unit 1 be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight.

B. Interstate Visibility Transport

We are proposing to disapprove Texas' SIP revisions addressing interstate visibility transport under CAA section 110(a)(2)(D)(i)(II) for six NAAQS. We further are proposing a FIP to fully address Texas' interstate visibility transport obligations for: (1) 1997 8-hour ozone, (2) 1997 $PM_{2.5}$ (annual and 24 hour), (3) 2006 $PM_{2.5}$ (24-hour), (4) 2008 8-hour ozone, (5) 2010 1-hour NO_2 and (6) 2010 1-hour SO_2. The proposed FIP is based on the finding that our proposed action to fully address the Texas Regional Haze BART program is adequate to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states in accordance with CAA section 110(a)(2)(D)(i)(II).

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Overview

This proposed action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). The proposed FIP would not constitute a rule of general applicability, because it only proposes source specific requirements for particular, identified facilities (8 total).

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. Section 3501 *et seq.* Because it does not contain any information collection activities, the Paperwork Reduction Act does not apply. See 5 CFR 1320(c).

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions. For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's proposed rule on small entities, I certify that this action will not have a significant impact on a substantial number of small entities. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. This rule does not impose any requirements or create impacts on small entities. This proposed FIP action under Section 110 of the CAA will not create any new requirement with which small entities must comply. This action, when finalized, will apply to 14 facilities owned by 8 companies, none of which are small entities. Accordingly, it affords no opportunity for the EPA to fashion for small entities less burdensome compliance or reporting requirements or timetables or exemptions from all or part of the rule. The fact that the CAA prescribes that various consequences (*e.g.,* emission limitations) may or will flow from this action does not mean that the EPA either can or must conduct a regulatory flexibility analysis for this action. We have therefore concluded that, this action will have no net regulatory burden for all directly regulated small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on state, local, and Tribal governments and the private sector. Under Section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to state, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any one year. Before promulgating an EPA rule for which a written statement is needed, Section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of Section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, Section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under Section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that Title II of UMRA does not apply to this proposed rule. In 2 U.S.C. Section 1502(1) all terms in Title II of UMRA have the meanings set forth in 2 U.S.C. Section 658, which further provides that the terms ''regulation'' and ''rule'' have the meanings set forth in 5 U.S.C. Section 601(2). Under 5 U.S.C. Section 601(2), ''the term 'rule' does not include a rule of particular applicability relating to . . . facilities.'' Because this proposed rule is a rule of particular applicability relating to 12 named facilities, EPA has determined that it is not a ''rule'' for the purposes of Title II of UMRA.

E. Executive Order 13132: Federalism

This proposed action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks [142] applies to any rule that: (1) Is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under Section 5–501 of the EO has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of SO_2, NO_X, and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires Federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use ''voluntary consensus standards'' (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical. EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. We have determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

[142] 62 FR 19885 (Apr. 23, 1997).

This proposed federal rule limits emissions of NO_X, SO_2, and PM from 14 facilities in Texas.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxides, Visibility, Interstate transport of pollution, Regional haze, Best available control technology.

Dated: December 9, 2016.

Ron Curry,

Regional Administrator, Region 6.

Title 40, chapter I, of the Code of Federal Regulations is proposed to be amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart SS—Texas

■ 2. Section 52.2287 is added to read as follows:

§ 52.2287 Best Available Retrofit Requirements (BART) for SO_2 and Particulate Matter and Interstate pollutant transport provisions; What are the FIP requirements for visibility protection?

(a) *Applicability.* The provisions of this section shall apply to each owner or operator, or successive owners or operators, of the coal or natural gas burning equipment designated below.

(b) *Definitions.* All terms used in this part but not defined herein shall have the meaning given them in the CAA and in parts 51 and 60 of this title. For the purposes of this section:

24-hour period means the period of time between 12:01 a.m. and 12 midnight.

Air pollution control equipment includes selective catalytic control units, baghouses, particulate or gaseous scrubbers, and any other apparatus utilized to control emissions of regulated air contaminants that would be emitted to the atmosphere.

Boiler-operating-day means 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.

Daily average means the arithmetic average of the hourly values measured in a 24-hour period.

Heat input means heat derived from combustion of fuel in a unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources. Heat input shall be calculated in accordance with 40 CFR part 75.

Owner or Operator means any person who owns, leases, operates, controls, or supervises any of the coal or natural gas burning equipment designated below.

PM means particulate matter.

Regional Administrator means the Regional Administrator of EPA Region 6 or his/her authorized representative.

Unit means one of the natural gas, gas and/or fuel oil, or coal-fired units covered in this section.

(c) *Emissions limitations and compliance dates for SO_2.* The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

Unit	Proposed SO_2 emission limit (lbs/MMBtu)	Compliance date (from the effective date of the final rule) (years)
Martin Lake 1	0.12	3
Martin Lake 2	0.12	3
Martin Lake 3	0.11	3
Monticello 3	0.05	3
Big Brown 1	0.04	5
Big Brown 2	0.04	5
Monticello 1	0.04	5
Monticello 2	0.04	5
Coleto Creek 1	0.04	5
Fayette 1	0.04	1
Fayette 2	0.04	1
Harrington 061B	0.06	5
Harrington 062B	0.06	5
J T Deely 1	0.04	5
J T Deely 2	0.04	5
W A Parish 5	0.04	5
W A Parish 6	0.04	5
Welsh 1	0.04	5

(d) *Emissions limitations and compliance dates for PM.* The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

(1) Coal-Fired Units at Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2.

(i) Normal operations: Filterable PM limit of 0.030 lb/MMBtu.

(ii) Work practice standards specified in 40 CFR part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042.

(2) Gas-Fired Units at Newman Unit 4; Wilkes Units 2 and 3; and W A Parish Unit 4 shall burn only pipeline natural gas, as defined in 40 CFR 72.1

(3) Gas-fired units that also burn fuel oil at Graham Unit 2; Newman Units 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes shall burn 0.7% sulfur content fuel or pipeline natural gas, as defined in 40 CFR 72.1.

(4) Compliance for the units included in Section (d) shall be as of the effective date of the final rule.

(e) *Testing and monitoring.* (1) No later than the compliance date of this regulation, the owner or operator shall install, calibrate, maintain and operate Continuous Emissions Monitoring Systems (CEMS) for SO_2 on the units covered under paragraph (c) of this section. Compliance with the emission limits for SO_2 shall be determined by using data from a CEMS.

(2) Continuous emissions monitoring shall apply during all periods of operation of the coal or natural gas burning equipment, including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments. Continuous monitoring systems for measuring SO_2 and diluent gas shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant in an hour) if data are unavailable as a result of performance of calibration, quality assurance, preventive maintenance activities, or backups of data from data acquisition and handling system, and recertification events. When valid SO_2 pounds per hour, or SO_2 pounds per million Btu emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments, emission data must be obtained by using other monitoring systems approved by the EPA to provide emission data for a minimum of 18 hours in each 24 hour period and at least 22 out of 30 successive boiler operating days.

(3) Compliance with the PM emission limits for units in paragraph (d)(1) shall be demonstrated by the filterable PM methods specified in 40 CFR part 63, subpart UUUUU, Table 7.

(f) *Reporting and recordkeeping requirements.* Unless otherwise stated all requests, reports, submittals, notifications, and other communications to the Regional Administrator required by this section shall be submitted, unless instructed otherwise, to the Director, Multimedia Division, U.S. Environmental Protection Agency, Region 6, to the attention of Mail Code: 6MM, at 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. For each unit subject to the emissions limitation in this section and upon completion of the installation of CEMS as required in this section, the owner or operator shall comply with the following requirements:

(1) For SO_2 each emissions limit in this section, comply with the notification, reporting, and recordkeeping requirements for CEMS compliance monitoring in 40 CFR 60.7(c) and (d).

(2) For each day, provide the total SO_2 emitted that day by each emission unit. For any hours on any unit where data for hourly pounds or heat input is missing, identify the unit number and monitoring device that did not produce valid data that caused the missing hour.

(3) Records for demonstrating compliance with the SO_2 and PM emission limitations in this section shall be maintained for at least five years.

(g) *Equipment operations.* At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(h) *Enforcement.* (1) Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(2) Emissions in excess of the level of the applicable emission limit or requirement that occur due to a malfunction shall constitute a violation of the applicable emission limit.

■ 3. In § 52.2304, paragraph (f) is added to read as follows:

§ 52.2304 Visibility protection.

* * * * *

(f) *Measures addressing disapproval associated with NO_X,* SO_2, and PM. (1) The deficiencies associated with NO_X identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by Section 52.2283.

(2) The deficiencies associated with SO_2 and PM identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by Section 52.2287.

[FR Doc. 2016–30713 Filed 1–3–17; 8:45 am]
BILLING CODE 6560–50–P

Exhibit D

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

SIERRA CLUB, et. al.,

Plaintiffs,

v.

CHRISTINE TODD WHITMAN, Administrator, United States Environmental Protection Agency,

Defendant.

Civil Action No. 00-2206 (CKK)/(JMF)

FILED

JUL 1 0 2002

NANCY MAYER WHITTINGTON, CLERK
U.S. DISTRICT COURT

MEMORANDUM OPINION

This case arises out of an action brought by Plaintiffs Sierra Club and Group Against Smog and Pollution (collectively "Sierra Club" or "Plaintiffs") under the citizen-suit provision of the Clean Air Act, 42 U.S.C. § 7604(a)(2) (1995) ("CAA"), alleging that Defendant United States Environmental Protection Agency ("EPA" or "Agency") failed to meet its statutory obligations to perform certain nondiscretionary duties required by the CAA. Sierra Club alleges, *inter alia*, that the Defendant failed to comply with the nonattainment determination and reclassification process required by the CAA with respect to the Birmingham Area in Alabama and Kent and Queen Anne's Counties in Maryland. Pursuant to Local Civil Rule 72.3, the Court referred Plaintiffs' Motion for Partial Summary Judgment and Defendant's Cross-Motion to Dismiss Certain Claims for Lack of Jurisdiction to Magistrate Judge John Facciola for report and recommendation. On March 11, 2002, Magistrate Judge Facciola recommended that this Court order EPA to publish formal attainment determinations for both the Birmingham Area and Kent and Queen Anne's Counties. After carefully reviewing the Magistrate Judge's recommendations, EPA's objections, Plaintiffs' response thereto, the entire record, and the relevant law, the Court

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adopts in part and rejects in part the Magistrate Judge's Report and Recommendation.

I. BACKGROUND

A thorough summary of the relevant facts of this case and the details of the relevant federal statutes are set forth in Part II of Magistrate Judge Facciola's Report and Recommendation and that discussion is incorporated herein by reference. A brief recitation of the facts of this case is discussed below.

A. *Statutory Background*

The CAA sets forth a comprehensive scheme for regulating air pollutant levels throughout the country. 42 U.S.C. §§ 7401, *et seq.* Under the CAA, the United States is divided into distinct "air quality control regions" which are designated by EPA as attainment or nonattainment areas for each regulated pollutant based on the measurement of that particular pollutant in the area. The 1990 Amendments to the CAA established a system of penalties and incentives for an area to achieve attainment status. An area is classified as a nonattainment area on a sliding scale from "marginal" to "extreme" depending on the number and severity of exceedances over the National Ambient Air Quality Standards ("NAAQS").[1] 42 U.S.C. § 7511(a)(1). An area will be "bumped up" or reclassified to a more severe classification if EPA determines that the area has not attained the NAAQS standard by the required attainment date. *See* 42 U.S.C. § 7511(b)(2)(A). An area must meet more exacting emissions standards if it is reclassified at a higher nonattainment status. 42 U.S.C. § 7511(a). If an area fails to achieve

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[1]The EPA is required to set primary National Ambient Air Quality Standards ("NAAQS") for pollutants that "cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare" 42 U.S.C. §§ 7408(a)(1)(A); 7409(b). Areas that fail to meet the NAAQS are designated as "nonattainment areas" and are required to reach attainment by certain 'attainment dates' set forth in the CAA. *See* 42 U.S.C. § 7407(d)(1)(A).

attainment by the required attainment date, the CAA imposes a nondiscretionary duty on EPA to publish a notice in the Federal Register six months after the attainment date identifying the areas that have failed to achieve attainment and reclassifying those areas to a higher non-attainment status. 42 U.S.C. § 7511(b)(2).

B. *Birmingham Area*

EPA concedes that pursuant to § 7511 (a)(1), it "should have made a determination on Birmingham's attainment status by May 15, 1994, but did not." Defendant's Cross Motion to Dismiss Certain Claims for Lack of Jurisdiction ("Def. Cross Mot.") at 11. EPA contends that it satisfied this statutory obligation, albeit late, when it published proposed and final actions in April and September of 1997, in response to and denying the State of Alabama's request for redesignation of the Birmingham area from nonattainment to attainment status. This denial, EPA argues, also served as the formal determination of attainment required by § 7511 (a)(1).[2] *See* 62 Fed. Reg. 23,421 (Apr. 30, 1997); 62 Fed Reg. 49,154 (Sept. 19, 1997) ("the 1997 Rules").

C. *Kent and Queen Anne's Counties*

EPA also concedes that it failed to make an attainment determination required by § 7511(b)(2) for the Kent and Queen Anne's Counties by the statutory deadline of November 15, 1993. However, EPA claims it satisfied its obligations with an attainment determination made on January 17, 1995, when EPA published a "Direct Final Rule" entitled "Clean Air Act Promulgation of Reclassification of Ozone Nonattainment Areas in Virginia, and Attainment Determinations." 60 Fed. Reg. 3,349 (1995) ("January 1995 Rule"). This Rule contained formal attainment determinations for several areas outside of Virginia, including Kent and Queen

[2] The State of Alabama's request for redesignation of the Birmingham area and the EPA's response were made pursuant to § 7407(d)(3).

Anne's Counties in Maryland. The January 1995 Rule concluded that the Maryland counties would remain at a marginal nonattainment status. *Id.* at 3,351.

On March 13, 1995, EPA published another rule entitled "Designation of Areas for Air Quality Planning Purposes; Virginia; Withdrawal of Final Rule Pertaining to the Clean Air Act Promulgation of Reclassification of the Hampton Roads Ozone Nonattainment Areas in Virginia and Attainment Determinations." 60 Fed. Reg. 13,368 (1995) ("March 1995 Rule"). This rule withdrew the portions of the January 1995 Rule that applied to the Virginia area, but explained that the rule had no effect on the attainment determinations in the January 1995 Rule relating to areas outside of Virginia, and listed all of those areas, except Maryland. *Id.*

D. *The Parties's Arguments*

The essence of Sierra Club's motion for partial summary judgment is that Defendant failed to comply with the nonattainment determination and reclassification process set forth in the CAA for ozone with respect to the Birmingham Area and Kent and Queen Anne's Counties. Specifically, Plaintiff contends that EPA failed to meet the six-month deadline imposed by 42 U.S.C. § 7511(b)(2) for EPA attainment determinations. Plaintiffs ask the Court to grant relief by requiring EPA to issue such determinations pursuant to this Court's power to "order the Administrator to perform any act or duty under this chapter which is not discretionary with the Administrator." 42 U.S.C. § 7604(a)(2).

Defendant, in its cross-motion to dismiss, argues that this Court lacks jurisdiction to determine whether EPA's Federal Register notices with respect to the areas at issue satisfy its obligations under § 7511 of the CAA. EPA claims that this Court's jurisdiction is limited to cases involving EPA's failure to perform a nondiscretionary act, and that because EPA has undertaken a final action, jurisdiction properly lies with the appropriate United States Court of

Appeals. *See* 42 U.S.C. § 7607(b)(1) (granting exclusive jurisdiction to the United States Court of Appeals for the appropriate Circuit to review the Agency's final actions).[3]

II. DISCUSSION

A. *Jurisdiction over EPA's Nondiscretionary Duties.*

At the threshold this Court must determine whether it has jurisdiction to determine the present controversy. Magistrate Judge Facciola concluded that this Court did indeed have jurisdiction to determine whether the Federal Register notices issued by EPA with respect to the Birmingham area and Kent and Queen Anne's Counties meet the non-discretionary obligations imposed by § 7511 of the CAA. He noted that "the statute's grant of jurisdiction to the District Courts to order EPA to perform a nondiscretionary duty must presuppose the District Court's jurisdiction to determine whether such duties have been performed in the first place." Report and Recommendation at 7.

The CAA clearly delineates the responsibilities of the Court of Appeals for the appropriate Circuit and the United States District Courts in reviewing decisions made by the EPA under the Act. In citizen-suits brought pursuant to 42 U.S.C. § 7604(a), District Courts are empowered to order EPA to perform non-discretionary obligations required by Act. *See* 42 U.S.C. § 7604(a); *Sierra Club v. Browner*, 130 F. Supp. 2d 78, 89 (D.D.C. 2001) ("The Court's power to grant relief in such suits is limited to 'ordering the Administrator to perform such act or duty [or] compelling . . . agency action unreasonably delayed.' 42 U.S.C. § 7604(a).").

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[3] Section 307(b) of the CAA provides that all challenges to nationally applicable regulations under the Clean Air Act must be brought in the United States Court of Appeals for the District of Columbia Circuit. 42 U.S.C. § 7607(b)(1). Challenges to locally or regionally applicable rules and final actions must be brought in the appropriate Court of Appeals for that locality. *Id.*

However, once the Agency takes a final action and performs a non-discretionary act, the Court of Appeals for the appropriate Circuit has exclusive jurisdiction to review the substance and validity of the Agency's final action. *See* 42 U.S.C. § 7607(b)(1). In the instant case, EPA characterizes its actions related to the promulgation of the 1997 and 1995 Rules as "final actions," and thus argues that the Court of Appeals has exclusive jurisdiction over the present controversy. EPA maintains that Magistrate Judge Facciola, in determining that jurisdiction properly lay with this Court, failed to distinguish between "(1) determining whether EPA has taken the mandated action and (2) determining whether EPA's actions complied with the substantive and procedural requirements of the APA, [Administrative Procedures Act, 5 U.S.C. § 553(b)(1996) ("APA")] and the CAA." EPA's Objections to Report and Recommendations of Magistrate Judge ("EPA's Objections") at 9. EPA asserts that although this Court has jurisdiction over the first, the Court of Appeals has the jurisdiction exclusively over the second. *Id.* In summary, EPA argues that any review of whether the 1995 and 1997 Rules are in fact "final actions" would require this Court to review the substantive merits of the Rules in direct contravention of 42 U.S.C. § 7604(a) of the CAA.

It is clear that this Court does not have jurisdiction to determine whether final actions undertaken by EPA are valid or lawful. However, the Court retains jurisdiction to determine whether the actions taken by EPA are in fact final actions. The Court agrees with the Magistrate Judge that to conclude otherwise would "render meaningless any grant of jurisdiction under § 7604(a) empowering a District Court to order EPA to perform a nondiscretionary duty." Report and Recommendation at 7. In this instance Plaintiffs contest that the actions taken by EPA in 1995 and 1997 in relation to the disputed areas are final actions satisfying the non-discretionary obligations set forth in § 7511 of the CAA. The relief requested by Plaintiff is limited to requiring EPA to undertake those non-discretionary obligations by publishing a final attainment determination. Plaintiff does not request that this Court make a determination regarding the validity or substance of those determinations; but merely that the Court order EPA to undertake its non-discretionary duty to make a determination. In order for the Court to determine whether EPA failed to perform a mandatory action under § 7511 of the CAA, it must examine EPA's actions to determine whether they meet the required non-discretionary standards of the CAA and the APA. Thus, because § 7604(a) grants the District Court the jurisdiction to hear suits which allege that EPA has failed to meet its nondiscretionary duties, the Court necessarily must determine whether EPA has met such duties and if the action taken is sufficient to constitute a final action.

This conclusion is supported by this Court's findings in *Sierra Club v. Browner*, 130 F. Supp.2d 78 (D.D.C. 2001), recently affirmed by the Court of Appeals for the District of Columbia in *Sierra Club v. Whitman*, 285 F.3d 63 (D.C. Cir. 2002). *Browner* declared that the limits of this Court's power "precludes [it] from assessing the substance of the agency's decision" and that "[s]ince the Court's power is limited to ordering EPA to take nondiscretionary action, *and since EPA has taken that action* . . . the Court is without power to grant meaningful relief. . . ." *Id.* at 82 (emphasis added). Nothing in the *Browner* opinion precludes the Court from determining whether EPA has in fact taken the required action. Moreover, the *Browner* court considered, at EPA's request, whether informal communications fulfilled its nondiscretionary duties under § 7511. The Court determined that it did have the jurisdiction to make such a determination stating that "the Court has jurisdiction to require that EPA make a determination. Quite plainly, the Court's jurisdiction does not extend to telling EPA what the determination should be. That limitation does not, however, eliminate the Court's jurisdiction altogether. Under the CAA, the Court unquestionably has the authority to require EPA to take nondiscretionary actions, such as reaching a determination." *Id.* at 89 n.16 (citations omitted).[4] Accordingly, the Court adopts the Magistrate Judge's recommendation and concludes that this Court has jurisdiction to review EPA's actions in order to determine whether those actions fulfill the non-discretionary requirements imposed by § 7511(b).

B. *Adequacy of EPA's Actions to Constitute Final Actions*

EPA does not dispute that attainment determinations must be made through notice and comment rulemaking prescribed by 5 U.S.C. § 553(b).[5] *See* EPA Objections at 9 n.6. Consistent with its position in *Browner*, EPA acknowledges that the CAA requires formal rulemaking procedures such that public notice must include publication and an opportunity for comment before a determination is final. *Browner*, 130 F. Supp. at 90; *see also Whitman*, 285 F.3d at 66

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[4]EPA further asserts that the jurisdictional conclusion reached in *Browner* does not apply in this case because EPA has not conceded that the formal rulemaking procedures had not been followed, as it admitted in *Browner*. However, this Court's jurisdiction is not contingent upon EPA's interpretations of its own actions. Rather, "[i]t is for the District Court, and not EPA, to decide whether EPA has actually taken final action." Report and Recommendation at 8. It is an established practice of this Court to determine whether an agency action constitutes final action for purposes of jurisdiction. *See Sierra Club v. Whitman*, 285 F.3d 63, 66-67 (D.C. Cir. 2002) (affirming the District Court's finding that EPA's informal attainment determinations were not final actions under the CAA); *Independent Petroleum Ass'n of America v. Babbit*, 971 F. Supp. 19, 27 (D.D.C. 1997) (noting that, under the APA, finality of agency action is a jurisdictional requirement that must be determined prior to any decision on the merits).

[5]EPA's interpretation of the CAA is reviewed under the standards set out in *Chevron U.S.A. Inc. v. Nat'l Res. Def. Council Inc.*, 467 U.S. 837 (1984). *See Sierra Club v. EPA*, 2002 U.S. App. LEXIS 13141 (D.C. Cir. July 2, 2002). When Congress "has directly spoken to the precise question at issue" the Court is required to "give effect to [the] unambiguously expressed intent." *Chevron*, 467 U.S. at 843. However, when a statute is ambiguous, the Court is required to defer to an agency's reasonable interpretations. *Id.* Section 7511(b)(2) of the CAA clearly requires EPA to reach an attainment determination. However, the statute is silent regarding what qualifies as such a determination, and thus, the Court will defer to the Agency's reasonable interpretation that formal notice and comment rulemaking is required for an attainment determination.

("EPA's established practice for making a final decision concerning nonattainment and reclassification is to conduct a rulemaking under the APA.") (quoting Brief of Appellee at 28). Accordingly, any attainment determination made pursuant to § 7511 of the CAA must conform to the formal notice and comment rulemaking standards set forth in the APA. *See Whitman*, 285 F.3d at 66 (explaining that "if there has not been a rulemaking there has not been an attainment determination.").

The APA has three elements for the notice requirement: "(1) a statement of the time, place, and nature of public rule making proceedings; (2) reference to the legal authority under which the rule is proposed; and (3) either the terms or substance of the proposed rule or a description of the subjects and issues involved." 5 U.S.C. § 553(b) (1995). The Court of Appeals for the District of Columbia has explained that "[t]he principal purpose of section 553 was to provide that the legislative functions of administrative agencies shall so far as possible be exercised only upon public participation on notice. . ." *Am. Bus. Ass'n v. United States*, 627 F.2d 525, 528 (D.C. Cir. 1980) (internal citations omitted). Under the APA, notice must "afford interested parties a reasonable opportunity to participate in the rulemaking process." *MCI Telecomm. Corp. v. FCC*, 274 F.3d 1136, 1140 (D.C. Cir. 1995) (quoting *Florida Power & Light Co. v. United States*, 846 F.2d 765, 771 (D.C. Cir. 1988)). In addition, the *Browner* Court stressed the importance of "a notice and comment period during which potentially affected parties can scrutinize the EPA's [actions]" because of the "weighty . . . consequence[s]" of the determinations. *Browner*, 130 F. Supp. at 91. Therefore, this Court will review the 1995 and 1997 Rules at issue to determine whether they adequately provide the public notice and opportunity for comment required by the APA, and by extension, the CAA.

1. Birmingham Area

EPA argues that consideration of a redesignation request cannot be done without also making an attainment determination, and therefore, not only was the attainment determination made, but the 1997 Rules also constitute notice to the public that EPA made such a determination. EPA's argument fails for several reasons. First, the titles and summaries of the 1997 Rules make no mention of an attainment determination and discuss only Alabama's redesignation request. *See McLouth Steel Products Corp. v. Thomas*, 838 F.2d 1317, 1322-23 (D.C. Cir. 1988) (finding that an agency's published notice inadequate where the title and the summary of the notice "would not have alerted a reader to the stakes"). Although the 1997 Rules make a passing reference to the area's attainment data from 1990 through 1994, no conclusion as to attainment is drawn from this data. *See* 62 Fed. Reg. at 23,421; 62 Fed. Reg. at 49,154. Additionally, the 1997 Rules fail to make "reference to the legal authority under which the rule is proposed" as is required by § 553(b)(2) of the APA. EPA does not reference § 7511(b) of the CAA and does not indicate that the 1997 Rules are proposed pursuant to that authority.

Moreover, EPA did not promulgate the 1997 Rules for the specific purpose of making an attainment determination for the Birmingham area. In *Whitman*, Sierra Club claimed that an attainment determination had been made for the St. Louis area in a 1998 EPA rule which listed areas that had attained ozone standards, yet omitted the St. Louis area. *Whitman*, 285 F.3d at 66 (citing 63 Fed. Reg. 31,014, 31,059 (June 5, 1998)). The court held that the "focus of the rule was not the St. Louis area's attainment status," and thus, the rule did not create an attainment determination. *Id.* Similarly in the present case, a passing reference to attainment data in an otherwise unrelated rule denying a redesignation request does not constitute an attainment determination. A rule must not only be made through formal rulemaking procedures, but must also focus specifically on the relevant determination, and therefore, EPA's 1997 Rule failed to make a formal attainment determination for the Birmingham area.

Finally, the 1997 Rules do not conform to the purposes of the APA by supplying the requisite notice to the public because as the Magistrate Judge noted, "[i]t would take no one less than a mindreader to interpret the 1997 Rules as an attainment determination for the Birmingham Area." Report and Recommendation at 12. Accordingly, this Court finds that the 1997 Rules do not constitute final attainment determinations for the Birmingham area because they failed to provide the necessary notice to the public and did not conform to the requirements of the APA, and by extension, the CAA.

2. Kent and Queen Anne's Counties

The Magistrate Judge also found that EPA's 1995 Rules do not constitute an attainment determination for Kent and Queen Anne's Counties because these rules do not provide proper notice to the public. Specifically, the Magistrate Judge believes the title of the 1995 Rules were misleading because a person searching for information pertaining to Kent and Queen Anne's Counties would not scrutinize a rule that only referenced Virginia in its title. The January 1995 Rule, however, does more than solely reference Virginia in its title. Rather, it adds a comma and an additional term "and Attainment Determinations," to delineate that this rule will discuss this subject as well. 60 Fed. Reg. at 3,349. Therefore, although the title did not specifically mention Maryland, it gave sufficient notice that the reader should have looked further to determine the attainment determinations made by the EPA.

Even assuming that this unspecific title alone is insufficient to constitute notice, the summary of the rule, located just below the title, specifically mentions the Maryland areas and that "this action determines that the Kent and Queen Anne's Counties, MD marginal ozone nonattainment area attained the ozone standard by November 1994." 60 Fed. Reg. at 3,349. In the analysis of this issue, the Magistrate Judge relied on *McLouth Steel Products Corp. v. Thomas*, 838 F.2d 1317, 1322-23 (D.C. Cir. 1988) which held that the agency's published notice was inadequate where both the title *and the summary* "would not have alerted a reader to the stakes." *Id.* at 1323. However, when an agency includes outlines at the beginning of its proposed rule which contain headings and subheadings which "clearly indicate[] the Notices would discuss" the relevant issues, "the outlines, and the Notices, [are] sufficiently informative to satisfy the requirements of the APA." *Chemical Waste Management, Inc. v. EPA*, 869 F.2d 1526, 1535 (D.C. Cir. 1989). Similarly here, where the summary at the beginning of the proposed rule specifically indicated that an attainment determination was made for Kent and Queen Anne's Counties in Maryland, the January 1995 Rule satisfies the notice requirements of the APA.

Accordingly, this Court concludes that the 1995 Rules relating Kent and Queen Anne's Counties in Maryland are final attainment determinations and thus rejects the Magistrate Judge's recommendation related to this issue.

3. Timing of Remedy

EPA requests that this Court grant it 164 days to comply with any order requiring it to make an attainment determination for the Birmingham area. EPA Objections at 14. In the alternative, if the Court adopts the recommendation of the Magistrate Judge that EPA be granted only 120 days, EPA requests that the Court set only the dates for signature of the final action and publication in the Federal Register. *Id.* The Court will not adopt the 164 day schedule requested by EPA. The attainment determination for Birmingham should have been made by May 15, 1994, and EPA has had ample time to make such a determination. The Court notes that the statutory duty to make an attainment determination is a non-discretionary mandate "to determine and publish by a date certain" *Browner*, 130 F. Supp. at 95. Therefore, the Court will accept the "reasonable middle ground," Report and Recommendation at 15, recommended by the Magistrate Judge and order EPA to publish the proposed determinations 45 days from the order accompanying this opinion. EPA will then have 30 days for public comment and forty-five days following the comment period in which to publish the final action in the Federal Register.

Accordingly, this Court will adopt the schedule proposed by Magistrate Judge Facciola.

CONCLUSION

After carefully reviewing Magistrate Judge Facciola's Report and Recommendation, Defendant's objections, Plaintiff's response thereto, and the relevant law, the Court concludes that the Report and Recommendation will be adopted in part and rejected in part. The Court concludes that the present case is properly before it and that EPA has failed to make a final attainment determination for the Birmingham, Alabama area as required by 42 U.S.C. § 7511(b). Therefore, the Court will require EPA to make a formal attainment determination for the Birmingham area within 120 days from the date of this opinion. This Court further finds that EPA has performed its non-discretionary duty to promulgate a formal attainment determination with respect to Kent and Queen Anne's Counties in Maryland. Accordingly, Plaintiffs' Motion for Partial Summary Judgment shall be granted in part and denied in part, and Defendant's Cross-Motion to Dismiss Certain Claims for Lack of Jurisdiction shall be granted in part and denied in part. An appropriate Order accompanies this Memorandum Opinion

July 9, 2002

COLLEEN KOLLAR-KOTELLY
United States District Judge

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

SIERRA CLUB, *et. al.*,

Plaintiffs,

v.

CHRISTINE TODD WHITMAN, Administrator, United States Environmental Protection Agency,

Defendant.

Civil Action No. 00-2206 (CKK)/(JMF)

FILED

JUL 1 0 2002

NANCY MAYER WHITTINGTON, CLERK
U.S. DISTRICT COURT

ORDER

For the reasons set forth in the accompanying Memorandum Opinion, it is this 9 day of July 2002, hereby

ORDERED that Defendant EPA's Cross-Motion to Dismiss Certain Claims for Lack of Jurisdiction [#43] shall be DENIED in part and GRANTED in part; and it is further

ORDERED that Plaintiffs' Motion for Partial Summary Judgment [#32] shall be DENIED in part and GRANTED in part; and it is further

ORDERED that EPA shall, no longer than 45 days from the date of this Order, publish the proposed determinations regarding whether the Birmingham, Alabama air quality control region attained the applicable ozone standard, and that following the publishing of the proposed determinations, EPA shall have 30 days for public comment. EPA shall then have no longer than forty-five days following the public comment period in which to publish the final determination in the Federal Register

SO ORDERED.

Colleen Kollar-Kotelly
COLLEEN KOLLAR-KOTELLY
United States District Judge

(N)

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Magistrate Judge John M. Facciola

Exhibit E

2002 WL 393069
United States District Court,
District of Columbia.

SIERRA CLUB, et al., Plaintiffs,
v.
Christine Todd WHITMAN, Administrator, United States Environmental Protection Agency, et al., Defendants.

Civil Action No. 00–2206 (CKK/JMF).
|
March 11, 2002.

REPORT AND RECOMMENDATION

JOHN M. FACCIOLA, Magistrate Judge.

***1** This matter is before me for report and recommendation pursuant to LCvR 72.3. I herein take up plaintiffs' *Motion for Partial Summary Judgment* ("Plains.Mot.") and defendants' *CrossMotion to Dismiss Certain Claims for Lack of Jurisdiction* ("Defs. Cross Mot.").

BACKGROUND

The Clean Air Act, 42 U.S.C.A. §§ 7401 et seq. (1995) ("CAA"), enacted in 1970 and amended in 1977 and 1990, was passed to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare and the productive capacity of its population." 42. U.S.C.A. § 7401(b)(1). The CAA regulates specific air pollutants that threaten public health and welfare. The key mechanism by which such pollutants are measured is the National Ambient Air Quality Standards ("NAAQS"). The NAAQS represent quantitative levels of a regulated pollutant in the outside air that the Environmental Protection Agency ("EPA") deems necessary to protect the public health and welfare. § 7409(b). Depending on the type pollutant, the NAAQS are typically measured in parts per million or billion.

Under the CAA, the United States is divided into distinct "air quality control regions," typically comprising a metropolitan area or surrounding counties. 42 U.S.C.A. § 7407(b). Each air quality control region is designated by EPA as an attainment or nonattainment area for each regulated pollutant based on its success in achieving the NAAQS for that particular pollutant. 42 U.S.C.A. § 7407(d). An air quality control region might be designated as an attainment area for carbon monoxide, say, but a nonattainment area for ozone. The requirements for achieving attainment vary according to the regulated pollutant, but most are based on the frequency with which a particular type of pollutant exceeds the NAAQS over a specified time period. In the case of ozone, an area is accorded nonattainment status if the number of exceedances averages less than one per year over a three-year period. 40 C.F.R. § 50, Appendix H. Nonattainment areas must adopt State Implementation Plans ("SIPs") specifying how they plan to achieve attainment. 42 U.S.C.A. § 7407(a).

The 1990 Amendments to the CAA established a system of penalties for nonattainment and incentives for achieving attainment status. Depending on the number and severity of exceedances of the NAAQS over this period, ozone nonattainment areas are classified as "marginal," "moderate," "serious," "severe," or "extreme." § 7511(a)(1); 57 Fed.Reg. 13506 (1992). If EPA determines that an area has not attained the NAAQS standard by the attainment date, the area is reclassified (a.k.a. "bumped up") by operation of law to a higher classification. §§ 7511(b)(2)(A). Generally, if an area is bumped up to a higher nonattainment status, it must meet more exacting emission standards. § 7511a.

The CAA imposes nondiscretionary duties on EPA in the event that an area fails to achieve attainment. In language that goes to the heart of this litigation, the CAA provides:

> ***2** (A) Within 6 months following the applicable attainment date (including any extension thereof) for an ozone nonattainment area, the Administrator shall determine, based on the area's design value (as of the attainment date), whether the area attained the standard by that date. Except for any Severe or Extreme area, any area that the Administrator finds has not attained the standard by that date shall be reclassified by operation of law in accordance with table 1 of subsection (a) of this section to the higher of—(i) the next higher classification for the area, or (ii) the classification applicable to the area's design value as determined at the time of the notice required under subparagraph (B) ...
>
> (B) The Administrator shall publish a notice in the Federal Register, no later than 6 months following the attainment date, identifying each area that the

> Administrator has determined under subparagraph (A) as having failed to attain and identifying the reclassification, if any, described under subparagraph (A).

§ 7511(b)(2); *see also* § 7509(c) for a virtually identical provision governing nonattainment determinations in general.[1]

1 The CAA allows a state to apply for up to two one-year extensions of the ozone attainment date. *Id.* § 7511(a)(5).

A separate provision of the CAA, § 7407(d)(3)(D), authorizes EPA to redesignate an area's attainment classification. Such redesignation may occur upon EPA's own initiative or upon a request from the state. In the typical state redesignation request, the state submits data showing that its air quality has improved enough to qualify for either an attainment designation or a less severe nonattainment designation. EPA then has 18 months to approve or deny such a request. § 7407(d)(3)(D). A redesignation, whether arising from a state's request or EPA's initiative, may only be promulgated if five specific requirements are met. § 7407(d)(3)(E). One of these requirements is that the area has attained the NAAQS for that pollutant.

The instant dispute is over whether or not EPA complied with the nonattainment determination and reclassification process for ozone with respect to the Birmingham Area, Alabama, and the Kent and Queen Annes County Area, Maryland.[2] Plaintiffs assert that the sixmonth deadlines for EPA's attainment determinations expired in the mid 1990's. EPA responds that it has in fact published these determinations as required, albeit belatedly. The material facts are not in dispute and resolution of this matter turns entirely on questions of law.

2 Plaintiffs' motion for summary judgment also sought injunctive relief for Salt Lake and Utah Counties, Utah, and Spokane County, Washington. Due to subsequent actions by the EPA, however, these claims are now moot and have been dismissed by the parties. *Stipulation to Dismissal,* October 11, 2001; *Order* (D.D.C. October 11, 2001).

Birmingham Area

Pursuant to the 1990 Amendment to the CAA, the Birmingham Area was classified as a marginal ozone nonattainment area. The statutory attainment date therefore was November 15, 1993. § 7511(a)(1). EPA concedes that it "should have made a determination on Birmingham's attainment status by May 15, 1994, but did not." Defs. Cross Mot. at 11.

However, EPA contends that proposed and final actions in 1997 under the § 7407(d)(3) redesignation provisions of the CAA also served as a formal determination of attainment for the purposes of § 7511(b)(2). In 1995, the State of Alabama submitted a request for a redesignation of the area from nonattainment to attainment pursuant to § 7407(d)(3)(D). In April and September 1997, respectively, EPA published a proposed and final disapproval of Birmingham's request. *See* 62 Fed.Reg. 23,421 (Apr. 30, 1997); 62 Fed.Reg. 49,154 (Sept. 19, 1997) (collectively "the 1997 Rules"). In both the proposed and final rules, EPA included a brief mention of the area's attainment data from 1990 through 1994. 62 Fed.Reg. at 23,421; *id.* at 49,155. EPA argues that this acknowledgment of attainment constitutes a formal attainment determination under § 7511(b)(2).

Kent and Queen Annes Counties Area

***3** This two-county area was originally designated as "marginal" for ozone nonattainment and had an attainment deadline of November 15, 1993. 56 Fed.Reg. 56,694 (1991); § 7511(a)(1). EPA thus had until May 15, 1994, to publish an attainment determination or a reclassification in the Federal Register. § 7511(b)(2). EPA concedes that no such action was taken by this date.

However, EPA asserts that it did perform its § 7511(b)(2) obligations through two Federal Register publications in 1995. First, on January 17, 1995, EPA published a "Direct Final Rule"[3] entitled "Clean Air Act Promulgation of Reclassification of Ozone Nonattainment Areas in Virginia, and Attainment Determinations ." 60 Fed.Reg. 3,349 (1995) ("January 1995 Rule"). Despite the title, the January 1995 Rule contained formal attainment determinations for several areas outside of Virginia, including areas in Delaware, New Jersey, Pennsylvania, West Virginia and the Kent and Queen Annes Counties Area in Maryland.[4] In particular, the notice included a finding that the Kent and Queen Annes Counties Area had not timely attained the ozone standard during the 1991–1993 period, but did attain the standard by the 1992–1994 period. 60 Fed.Reg. at 3,351. Based on the 1992–1994 values, EPA essentially compromised by declining to bump up the Kent and Queen Annes Counties Area to moderate status but also in extending its marginal nonattainment status. *Id.* at 3,351.

3 By entitling the notices as a "Direct Final Rule," EPA intended the rule to go into effect without prior proposal unless a person notified it within 30 days that he wished to file a critical comment. 60 Fed.Reg. 3,349.

4 The rule also included a proposed new EPA method for making attainment determinations, but this section is not at issue here.

On March 13, 1995, EPA published another rule entitled "Designation of Areas for Air Quality Planning Purposes; Virginia; Withdrawal of Final Rule Pertaining to the Clean Air Act Promulgation of Reclassification of the Hampton Roads Ozone Nonattainment Areas in Virginia and Attainment Determinations." 60 Fed.Reg. 13,368 (1995) ("March 1995 Rule"). This rule withdrew the portion of the January 1995 Rule that applied to the Virginia area. It also professed to have no effect on the attainment determinations in the January 1995 Rule with respect to the areas outside of Virginia, and expressly listed all of the relevant states *except Maryland. Id.*

DISCUSSION

Jurisdiction to Determine Whether EPA's Actions Satisfy Its Nondiscretionary Determination and Publication Duties

Plaintiffs Sierra Club and Group Against Smog and Pollution (collectively "Sierra Club") bring this action under the citizen-suit provision of the CAA. This provision grants a private right of action against the Administrator of EPA "where there is alleged a failure of the Administrator to perform any act or duty under this chapter which is not discretionary with the Administrator ." 42 U.S.C.A. § 7604(a)(2). In a citizen suit, the court may grant relief "order[ing] the Administrator to perform such act or duty [or] compel[ling] ... agency action unreasonably delayed." § 7604(a); *Sierra Club v. Browner,* 130 F.Supp.2d 78, 89 (D.D.C.2001).

EPA argues that this court has no jurisdiction to determine whether its Federal Register notices with respect to the Birmingham Area and the Kent and Queen Annes Counties Area satisfied its obligations under § 7511 of the CAA. Rather, the EPA claims that the issue falls under § 7607(b)'s grant of exclusive jurisdiction to the Circuit Court to review the Agency's "final actions." EPA does not dispute that the duty to make and publish an attainment determination is nondiscretionary. Rather, EPA asserts that because the agency has already taken final action, any challenge to that decision falls under the exclusive jurisdiction of the Circuit Court.

***4** EPA's interpretation of § 7607(b) would render meaningless any grant of jurisdiction under § 7604(a) empowering a District Court to order EPA to perform a nondiscretionary duty. As a logical matter, the statute's grant of jurisdiction to the District Courts to order EPA to perform a nondiscretionary duty must presuppose the District Courts' jurisdiction to determine whether such duties have been performed in the first place. Aside from the obvious case, such as in Spokane County, where EPA concedes that it has done absolutely nothing to fulfill its nondiscretionary duties, it is difficult to conjure a situation where a plaintiff alleges a failure to perform a nondiscretionary that does not require the court to determine whether some action by EPA qualifies as a formal attainment determination.

EPA's argument is further undercut by the plain language of § 7604(a), which gives the District Court jurisdiction when a private plaintiff has "*alleged a failure of the Administrator to perform* " a nondiscretionary duty. § 7604(a)(emphasis added). This is precisely what has occurred here. Sierra Club maintains that EPA's notices pertaining to both the Kent and Queen Annes Counties Area and the Birminham Area constitute a failure to perform its nondiscretionary duties pursuant to § 7511.

Moreover, Sierra Club seeks the limited remedy of ordering EPA to perform these duties, not a review of the substance of any action. EPA protests that Sierra Club's ultimate goal is to challenge the substance of the determinations made with respect to each nonattainment area. However, this challenge could not now be brought under § 7607(b) because that provision imposes a 60 day statute of limitations on such claims and that period would have long since passed if EPA's actions were to be viewed as formal determinations. EPA appears deeply aggrieved that by having to issue a formal determination now, Sierrra Club will have an opportunity to challenge the substance of the determination.[5] In fact, Sierra Club readily concedes that it will petition for review in the event that it prevails in this action. Plains. Reply at 7 n. 6. But Sierra Club argues, and rightly so, that its ultimate objective is irrelevant to the immediate issue of whether EPA has performed its nondiscretionary duties under § 7511(b). Indeed, it is equally irrelevant to the jurisdictional question.

5 In other words, if the court determines that EPA's January 1995 Rule and 1997 Rule constitute formal

attainment determinations, Sierra Club will have no opportunity to bring an action in Circuit Court, because § 7607(b) sets a 60–day statute of limitations for such actions. Thus, only by bringing the claim under § 7511(b) and forcing EPA to issue a determination will Sierra Club have the opportunity to overturn the substantive outcome.

In short, EPA is quite right when it contends that "[o]nce EPA has taken action, the jurisdiction of this Court ends." Defs. Cross Mot. at 10. But read more closely, EPA essentially argues that once EPA itself is convinced that it has taken a final action in fulfillment of its nondiscretionary duties, the District Court has no jurisdiction to visit this issue. This is flatly inconsistent with the language of § 7604(a). It is for the District Court, and not EPA, to decide whether EPA has actually taken final action. *See, e.g., Mobil Oil Corp. v. Department of Energy,* 610 F.2d 796, 804 (Temp.Emer.Ct.App.1979), *cert. denied,* 446 U.S. 937 (1980)(upholding a District Court's nullification of an agency action); *Chemical Mfrs. Ass'n v. E.P.A.,* 26 F.Supp.2d 180, 182 (D.D.C.1998)(District Court interpreted whether EPA's action qualified as a final action under the APA); *Independent Petroleum Ass'n of America v. Babbitt,* 971 F.Supp. 19, 27 (D.D.C.1997)(same).

***5** Finally, it is worth pointing out that EPA acknowledged the court's jurisdiction in *Sierra Club v. Browner* when it urged the court to resolve the very same substantive issue here-whether its actions fulfilled its nondiscretionary duties under § 7511. In response to private intervenors who did raise the jurisdictional issue, the court determined that it did indeed have such jurisdiction.[6] EPA's change of view directly contradicts both its own earlier position and the court's interpretation of § 7604(a) in *Sierra Club v. Browner.*[7]

6 "... [T]he Court has jurisdiction to require that EPA make a[n attainment] determination. Quite plainly, the Court's jurisdiction does not extend to telling EPA what the determination should be. That limitation does not, however, eliminate the Court's jurisdiction altogether. Under the CAA, the Court unquestionably has the authority to require EPA to take nondiscretionary actions, such as reaching a determination ... *EPA itself endorses this view of the statute.*" *Sierra Club v. Browner,* 130 F.Supp.2d at 89 n. 16 (emphasis added).

7 EPA makes the additional argument that the District Court lacks jurisdiction to consider whether EPA complied with the APA's procedural requirements, citing to *Husqvarna AB v. EPA,* 254 F.3d 195, 202 (D.C.Cir.2001), and *Small Refinder Lead Phase–Down Task Force v. U.S.E.P.A.,* 705 F.2d 506, 547 (D.C.Cir.1983). These cases are mere examples of the Circuit Court's determining whether EPA complied with the procedural requirements of the CAA as a part of its § 7607(b) review of an EPA final action. They in no way stand for the broad proposition that a District Court may not make a similar determination in considering whether EPA performed a nondiscretionary duty.

Adequacy of EPA's Actions

The jurisdictional issue is not the only position in *Sierra Club v. Browner* that EPA has now abandoned. In fact, both Sierra Club and EPA apparently have reversed themselves on a major point of contention—the degree of formality required of EPA's § 7511(b) attainment determinations and the publication thereof. In *Sierra Club v. Browner,* EPA adopted the position that a notice constitutes an attainment determination only if it has been published and there has been an opportunity for comment. *Id.* at 90. EPA, in other words, interpreted the attainment and reclassification procedure under § 7511(b)(2) as a rulemaking process, subject to the Administrative Procedure Act's requirements for notice and comment at 5 U.S.C.A. § 553(b)(1996). Sierra Club, in turn, argued that a series of letters, comments and other publications together qualified as a nonattainment determination for the St. Louis Area. *Id.* at 90. The court, deferring to EPA in accordance with *Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.,* 467 U.S. 837 (1984), found EPA's interpretation of § 7511(b)(2) both reasonable and consistent with the purpose of the CAA. *Sierra Club v. Browner* at 90–92. In particular, the court noted the value of public scrutiny and input in ensuring that EPA made reasonable and informed decisions on the often "complex" and "weighty" attainment determinations. *Id.* at 91.

In the instant case, EPA contends that the January 1995 Rule and the 1997 Rules constitute formal attainment determinations for the purposes of § 7511(b)(2). In its argument, EPA ignores its past urging in *Sierra Club v. Browner* for a strict interpretation of § 7511(b)(2) as an APA rulemaking, instead asserting that Sierra Club should have discovered and interpreted the January 1995 Rule and the 1997 Rules as formal attainment determinations. Sierra Club, meanwhile, eagerly embraces the court's ruling against it in *Sierra Club v. Browner* to support its position that the January 1995 Rule and the

1997 Rules in no way meet the rulemaking requirements of the APA.

The APA sets forth three elements to the notice requirement: "(1) a statement of the time, place, and nature of public rule making proceedings; (2) reference to the legal authority under which the rule is proposed; and (3) either the terms or substance of the proposed rule or a description of the subjects and issues involved." 5 U.S.C.A. § 553(b). In addition, the D.C. Circuit consistently has held that notice under this provision must "afford interested parties a reasonable opportunity to participate in the rulemaking process." *MCI Telecommunications Corp. v. F.C.C.,* 57 F.3d 1136, 1140 (D.C.Cir.1995)(*quoting Florida Power & Light Co. v. United States,* 846 F.2d 765, 771 (D.C.Cir.1988)); *Water Transport Ass'n v. I.C.C.,* 684 F.2d 81, 84 (D.C.Cir.1982)(*quoting Forester v. Consumer Product Safety Commission,* 559 F.2d 774, 787 (D.C.Cir.1977), and *Logansport Broadcasting Corp. v. United States,* 210 F.2d 24, 28 (D.C.Cir.1954)); *see also Conference of State Bank Sup'rs v. Office of Thrift Supervision,* 792 F.Supp. 837 (D.D.C.1992).

***6** Furthermore, *Connecticut Light & Power Co. v. Nuclear Regulatory Commission,* 673 F.2d 525, 530 (D.C.Cir.1982) *cert. denied* 459 U.S. 835 (1982), held that notice of a proposed rulemaking should provide an accurate picture of the agency's reasoning so that interested parties may comment meaningfully upon the agency's proposed rule. *See also Sargent v. Block,* 576 F.Supp. 882, 891 (D.D.C.1983)(holding that proposed rule complied with APA notice provision where it clearly set forth issue and the ramifications of the proposed rule). Finally, *Small Refiner Lead Phase–Down Task Force v. Environmental Protection Agency,* 705 F.2d 506 (D.C.Cir.1983), held that the adequacy of an agency's notice must be interpreted in light of the policies of openness and accessibility that underlie the notice requirement. *Id.* at 547.

Together, these cases set forth the basic standards that EPA's rules must meet in order to qualify under the APA and by extension the CAA. The adequacy of an agency's notice is determined on a case-by-case review in light of the relevant circumstances. *United Church Board for World Ministries v. Securities and Exchange Comm'n,* 617 F.Supp. 837, 839 (D.D.C.1985).

All of the circumstances surrounding EPA's January 1995 Rule and 1997 Rules lead me to conclude that these notices were inadequate. As to the January 1995 Rule, the most glaring error was the misleading title. Given the enormous volume of information published in the Federal Register, the importance of accurate and precise titles cannot be overstated. It is entirely unreasonable to expect someone searching for information pertaining to the Kent and Queen Annes Counties Area to scrutinize a proposed rule that referenced only Virginia in the title. This expectation is all the more unreasonable given that EPA's standard operating practice is to reference the geographic areas in its attainment determinations. Plains. Reply at 5. As stated in *National Air Transportation Assn' v. McArtor,* 866 F.2d 483 (D.C.Cir.1989), "[a]n agency may not put up signs inducing a set of readers to turn aside and then claim they had constructive notice of what they would have found at the end of the road." *Id.* at 485; *See also McLouth Steel Products Corp. v. Thomas,* 838 F.2d 1317, 1322–23 (D.C.Cir.1988)(holding that misleading headings can render notice inadequate). Plaintiff further contends that the March 1995 Rule, by omitting any mention of Maryland or the Kent and Queen Annnes Counties Area, further added to the ambiguity surrounding the status of the area. Finally, I note that the misleading title of the notice was more than harmless error. In fact, Sierra Club contends, and EPA does not dispute, that Sierra Club had no actual notice of the purported attainment determination until after it had served its notice of intent to sue in this action. Plains. Mot. at 12 n. 6.

The 1997 Rules present an even more egregious failure. It would take no one less than a mindreader to interpret the 1997 Rules as an attainment determination for the Birmingham Area. These rules were issued in response to a request to redesignate the Birmingham Area from nonattainment to attainment status, a process distinct from the attainment and bump up processes. The titles and summaries of the 1997 Rules expressly reference the redesignation request but make no mention of an attainment determination. Moreover, the respective "Proposed Action" and "Final Action" sections of proposed and final rules discuss only the redesignation request. The proposed rule includes no invitation to comment on the purported attainment determination. In fact, the sole mention of the area's attainment status is found in the introductory sections of these rules, where EPA writes the following two sentences:

> ***7** The State submitted its request for redesignation on March 16, 1995. The request included information showing that the Birmingham area had three years of air quality attainment data from 1990–1993. The area continued to maintain the ozone NAAQS through 1994.

62 Fed.Reg. at 23,421; *id.* at 49,155.

EPA asserts that these two sentences qualify as a formal attainment determination under § 7511(b)(2). Such an argument fails for several reasons. Notably, the text itself does not expressly reference § 7511(b)(2), as required by 5 U.S.C.A. § 553(b)(2). Sierra Club points to several other EPA attainment determinations that expressly reference § 7511(b)(2) and are identified as attainment determinations *per se.* Plains. Reply at 5. EPA offers no explanation for why it did not do so here.

Moreover, EPA does not and cannot seriously contend that its brief mention of the Birmingham Area's attainment data from 1990 through 1994 passes muster under the "reasonable opportunity to participate" standard. Its argument that the public should have been on notice because an area's attainment status is a threshold question in the redesignation rulemaking is incorrect. First, EPA denied the redesignation request, thus the importance placed on the purported attainment determination was minimal at best. Second, the relevant attainment data for a redesignation request is *as of the date of the request,* not as of the attainment date under § 7511(b)(2). Here, Alabama requested a redesignation in 1995, but the attainment date for the purposes of § 7511(b)(2) was May 15, 1994. How attainment data from 1990 through 1994 becomes an "essential" component of the redesignation request is beyond me.

Vahle v. Carol Browner, Civ. No. 97–G–3150–S (N.D.Ala. September 4, 1998), does not influence my recommendation in any way. In *Vahle,* the court held that the 1997 Rules did qualify as an attainment determination for the Birmingham Area. Both parties acknowledge that this case has no *res judicata* effect in the present action, given that plaintiffs were not parties thereto. Furthermore, in the subsequent case of *Sierra Club v. Browner,* EPA substantially changed its position with respect to the notice requirements of § 7511(b)(2) and in the process eroded the authority of *Vahle.* It appears that the APA's notice standards never arose in *Vahle,* as the court simply cites to the 1997 Rules without exploring the adequacy of the notice. Under these circumstances, I have not accorded *Vahle* any serious consideration.

In sum, I seriously doubt that EPA itself ever intended the 1997 Rules to serve as a formal attainment determination. Even if this were the case, the public cannot reasonably be expected to connect the dots and recognize these two sentences as an attainment determination. *See, e.g., Wagner Electric Corp. v. Volpe,* 466 F .2d 1013, 1019–20 (3rd Cir.1972)(notice inadequate where only "some knowledgeable" manufacturers would grasp link between subject notice identified and broader subject of final rule). If the public, including two environmental organizations promoting strict enforcement of the CAA, cannot even recognize a publication as notice, it follows *a fortiori* that such notice fails to meet the standards of the APA. To confer attainment determination status on EPA's two-sentence allusion to attainment data in the context of a lengthy rejection of a redesignation request would undermine the APA's policy of encouraging public comments in the rulemaking prcoess. In reaching this conclusion, I am simply holding EPA to the high notice standards that it set for itself in *Sierra Club v. Browner.*

***8** I therefore recommend that EPA be ordered to publish formal attainment determinations for the Birmingham Area and the Kent and Queen Annes Counties Area.

Timing of Remedy

Sierra Club originally requested an order giving EPA 90 days to publish final attainment and reclassification determinations for both the Birmingham and Kent and Queen Annes Counties Areas. EPA requests 164 days for both areas. In its reply, Sierra Club has indicated that, if pressed, it would be willing to allow 120 days for final publication, and this appears to be a reasonable middle ground. I therefore recommend that EPA be given 45 days from Judge Kollar Kotelly's order to publish the proposed determinations, another 30 days for public comment, followed by 45 more days to publish the final action in the Federal Register.

Failure to file timely objections to the findings and recommendations set forth in this report may waive your right of appeal from an order of the District Court adopting such findings and recommendations. *See Thomas v. Arn,* 474 U.S. 140 (1985).

All Citations

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