In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where the EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the proposed rule does not have tribal implications and will not impose substantial direct costs on tribal governments or preempt tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Ammonia, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide, Volatile organic compounds.

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

Dated: June 30, 2017.

Debra H. Thomas,

Acting Regional Administrator, Region 8.

[FR Doc. 2017–14748 Filed 7–12–17; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2017–0129; FRL–9964–20–Region 6]

Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or the Act), the Environmental Protection Agency (EPA) is proposing to approve for the Entergy R. S. Nelson facility (Nelson) (1) a portion of a revision to the Louisiana Regional Haze State Implementation Plan (SIP) submitted on February 20, 2017; and (2) a revision submitted for parallel processing on June 20, 2017, by the State of Louisiana through the Louisiana Department of Environmental Quality (LDEQ). Specifically, the EPA is proposing to approve these two revisions, which address the Best Available Retrofit Technology requirement of Regional Haze for Nelson for sulfur-dioxide (SO_2) and particulate-matter (PM).

DATES: Written comments must be received on or before August 14, 2017.

ADDRESSES: Submit your comments, identified by Docket No. EPA–R06–OAR–2017–0129, at *http://www.regulations.gov* or via email to *R6_LA_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 Jennifer Huser, *huser.jennifer@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 *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).

FOR FURTHER INFORMATION CONTACT: Jennifer Huser, 214–665–7347, *huser.jennifer@epa.gov.* To inspect the hard copy materials, please schedule an appointment with Jennifer Huser or Mr. Bill Deese at 214–665–7253.

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

Table of Contents

I. Background

A. The Regional Haze Program

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 adverse health effects and mortality in humans; it also contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, "Interagency Monitoring of Protected Visual Environments" (IMPROVE), shows 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 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. CAA programs have reduced some haze-causing pollution, lessening some visibility impairment and resulting in partially improved average visual ranges.

CAA requirements to address the problem of visibility impairment continue to be 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. On December 2, 1980, the 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.'' These regulations represented the first phase in addressing visibility impairment. The 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 the EPA promulgated regulations addressing regional haze in 1999. The Regional Haze Rule revised the existing visibility regulations to add 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.

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 built between 1962 and 1977 procure, install, and operate the ''Best Available Retrofit Technology'' (BART). Larger ''fossil-fuel fired steam electric plants'' are one of these 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 other alternative program as long as the alternative provides for greater progress towards improving visibility than BART.

B. Our Previous Actions and Our Proposed Action on Louisiana Regional Haze

On June 13, 2008, Louisiana submitted a SIP to address regional haze (2008 Louisiana Regional Haze SIP or 2008 SIP revision). We acted on that submittal in two separate actions. Our first action was a limited disapproval [1] because of deficiencies in the State's regional haze SIP submittal arising from the remand by the U.S. Court of Appeals for the District of Columbia of the Clean Air Interstate Rule (CAIR). Our second action was a partial limited approval/partial disapproval [2] because the 2008 SIP revision met some but not all of the applicable requirements of the CAA and our regulations as set forth in sections 169A and 169B of the CAA and 40 CFR 51.300–308, but as a whole, the 2008 SIP revision strengthened the SIP. On August 11, 2016, Louisiana submitted a SIP revision to address the deficiencies related to BART for four non-EGU facilities. We proposed to approve that revision on October 27, 2016.[3]

On February 10, 2017, Louisiana submitted a SIP revision intended to address the deficiencies related to BART for EGU sources (February 2017 Louisiana Regional Haze SIP or February 2017 SIP revision). We proposed approval of that SIP revision as it pertains to all of the BART-eligible EGUs in the State on May 19, 2017, except for Nelson, which we address herein.[4]

On June 20, 2017, Louisiana submitted a SIP revision with a request for parallel processing, specifically addressing the BART requirements for Nelson. (June 2017 Louisiana Regional Haze SIP or June 2017 SIP revision). This revision, along with the Nelson portion of the February 20, 2017 SIP revision, are the subject of this proposed action. Parallel processing of the June 2017 SIP revision means that, at the same time Louisiana is completing the corresponding public comment and rulemaking process at the state level, we are proposing action on it. Because Louisiana has not yet finalized the June 2017 SIP revision that we are parallel processing, we are proposing to approve this SIP revision in parallel with Louisiana's rulemaking activities. If changes are made to the State's proposed rule after the EPA's notice of proposed rulemaking, such changes must be acknowledged in the EPA's final rulemaking action. If the changes are significant, then the EPA may be obligated to withdraw our initial proposed action and re-propose. If there are no changes to the parallel-processed version, EPA would proceed with final rulemaking on the version finally adopted by Louisiana and submitted to EPA, as appropriate after consideration of public comments.

II. Our Evaluation of Louisiana's BART Analysis for Nelson

Nelson is located in Westlake, Calcasieu Parish, Louisiana. The nearest Class I areas are Breton National Wilderness Area in Louisiana, located 264 miles east of the facility and Caney Creek Wilderness Area in Arkansas, located 286 miles north of the facility.

A. Identification of Nelson as a BART-Eligible Source

In our partial disapproval and partial limited approval of the 2008 Louisiana Regional Haze SIP, we approved the LDEQ's identification of 76 BART-eligible sources, which included Nelson.[5] Nelson is a fossil-fuel steam electric power generating facility and operates three BART-eligible steam generating units: Unit 4, Unit 4 Auxiliary Boiler, and Unit 6.

B. Evaluation of Whether Nelson Is Subject to BART

Because Louisiana's 2008 Regional Haze SIP relied on CAIR as a BART alternative for EGUs, the submittal did not include a determination of which BART-eligible EGUs were subject to BART. On May 19, 2015, we sent a CAA Section 114 letter to the Nelson BART-eligible source in Louisiana. In that letter, we noted our understanding that the source was actively working with the LDEQ to develop a SIP. However, in order to be in a position to develop a FIP should that be necessary, we requested information regarding the BART-eligible sources, including Nelson. The Section 114 letter required the source to conduct modeling to determine if the source was subject to BART, and included a modeling protocol. The letter also requested that a BART analysis be performed in accordance with the BART Guidelines for Nelson if determined to be subject to BART. We worked closely with the BART-eligible facility and with the LDEQ to this end, and all the information we received from the

[1] 77 FR 33642 (June 7, 2012).

[2] 77 FR 39425 (July 3, 2012).

[3] 81 FR 74750 (October 27, 2016).

[4] 82 FR 22936 (May 19, 2017).

[5] See 77 FR 11839 at 11848 (February 28, 2012).

facility was also sent to the LDEQ. As a result, the LDEQ submitted the February and June SIP revisions addressing BART for Nelson. The LDEQ provides a BART determination for each of the three units at the source for all visibility impairing pollutants except NO_X.[6] Once a list of BART-eligible sources still in operation within a state has been compiled, the state must determine whether to make BART determinations for all of them or to consider exempting some of them from BART because they are not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area. The BART Guidelines present several options that rely on modeling analyses and/or emissions analyses to determine if a source is not reasonably anticipated to cause or contribute to visibility impairment in a Class I area. A source that is not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area is not ''subject to BART,'' and for such sources, a state need not apply the five statutory factors to make a BART determination.[7] Sources that are reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are subject to BART.[8] For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that the LDEQ identify the level of control representing BART after considering the factors set out in CAA section 169A(g)(2). To determine which sources are anticipated to contribute to visibility impairment, the BART Guidelines state ''you can use CALPUFF or other appropriate model to estimate the visibility impacts from a single source at a Class I area.''[9]

1. Visibility Impairment Threshold

The preamble to the BART Guidelines advise that, ''for purposes of determining which sources are subject to BART, States should consider a 1.0 deciview [10] change or more from an individual source to 'cause' visibility impairment, and a change of 0.5 deciviews to 'contribute' to impairment.'' [11] They further advise that ''States should have discretion to set an appropriate threshold depending on the facts of the situation,'' and describes situations in which states may wish to exercise that discretion, mainly in situations in which a number of sources in an area are all contributing fairly equally to the visibility impairment of a Class I area. In Louisiana's 2008 Regional Haze SIP submittal, the LDEQ used a contribution threshold of 0.5 dv for determining which sources are subject to BART, and we approved this threshold in our previous action.[12]

2. CALPUFF Modeling to Screen Sources

The BART Guidelines recommend that the 24-hour average actual emission rate from the highest emitting day of the meteorological period be 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 baseline period (2000–2004) for the source is identified through a review of the daily emission data for each BART-eligible unit from the EPA's Air Markets Program Data.[13] Because daily emissions are not available for PM, maximum 24-hr PM emissions are estimated based on permit limits, maximum heat input, and AP–42 factors, and/or stack testing. EPA conducted CALPUFF modeling and provided it to LDEQ to determine whether Nelson causes or contributes to visibility impairment in nearby Class I areas (see Appendix F of the June 2017 SIP revision). See the CALPUFF Modeling TSD for additional discussion on modeling protocol, model inputs, and model results for this portion of the screening analysis. The CALPUFF modeling establishes that Nelson's visibility impacts are above LDEQ's chosen threshold of 0.5 dv.

3. Nelson Is Subject to BART

The BART-eligible units at the Nelson facility have visibility impacts greater than 0.5 dv. Therefore, Nelson is subject to BART and must undergo a five-factor analysis. See our CALPUFF Modeling TSD for further information.

We note that, in addition to CALPUFF modeling, Appendix D of the February 2017 SIP revision includes the results of CAMx modeling [14] performed by Trinity consultants for Entergy. This modeling purports to demonstrate that the baseline visibility impacts from Nelson [15] are significantly less than the 0.5 dv threshold. However, this modeling was not conducted in accordance with the BART Guidelines or a previous modeling protocol we developed for the use of CAMx modeling for BART screening,[16] and does not properly assess maximum baseline impacts. Therefore, we agree with LDEQ's decision in the February 2017 SIP revision to not rely on this CAMx modeling.[17] See the CAMx Modeling TSD for a detailed discussion. We also note that, for the largest emission sources in Louisiana, such as the Nelson facility, we performed our own CAMx modeling while following the BART Guidelines and the modeling protocol to provide additional information on visibility impacts and impairment and address possible concerns with utilizing CALPUFF to assess visibility impacts at Class I areas located at large distances from the emission sources. Our CAMx modeling indicates that Nelson has a maximum impact [18] of 2.22 dv at Caney Creek, with 31 days out of the 365 days modeled exceeding 0.5 dv, and 9 days exceeding 1.0 dv. See the CAMx Modeling TSD for additional information on the EPA's CAMx modeling protocol, inputs, and model results.

[6] We have previously proposed approval of the portion of LDEQ's February 2017 revision that relies on CSAPR participation as an alternative to source-specific EGU BART for NO_X, therefore, a source by source analysis for NO_X is unnecessary. 82 FR 22936, at 22943.

[7] See 40 CFR part 51, Appendix Y, III, How to Identify Sources ''Subject to BART''.

[8] *Id.*

[9] See 40 CFR part 51, Appendix Y, III, How to Identify Sources ''Subject to BART''.

[10] As we note in the Regional Haze Rule (64 FR 35725, July 1, 1999), the ''deciview'' or ''dv'' is an atmospheric haze index that expresses changes in visibility. This visibility metric expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions.

[11] 70 FR 39104, 39120 (July 6, 2005), [40 CFR part 51, Appendix Y].

[12] See, 77 FR 11839, 11849 (February 28, 2012).

[13] *http://ampd.epa.gov/ampd/.*

[14] CAMx Modeling Report, prepared for Entergy Services by Trinity Consultants, Inc. and All 4 Inc, October 14, 2016, included in Appendix D of the February 2017 Louisiana Regional Haze SIP submittal.

[15] Entergy's CAMx modeling included model results for Michoud, Little Gypsy, R.S. Nelson, Ninemile Point, Willow Glen, and Waterford.

[16] Texas was the only state that developed a modeling protocol, which EPA approved, to screen sources using CAMx. Texas had over 120 BART-eligible facilities located at a wide range of distances to the nearest class I areas in their original Regional Haze SIP. CAMx modeling was appropriate in that instance due to the distances between sources and Class I areas and the number of sources. Texas worked with EPA and FLM representatives to develop this modeling protocol, which proscribed how the modeling was to be performed and what metrics had to be evaluated for determining if a source screened out. See Guidance for the Application of the CAMx Hybrid Photochemical Grid Model to Assess Visibility Impacts of Texas BART Sources at Class I Areas, ENVIRON International, December 13, 2007, available in the docket for this action. EPA, the Texas Commission on Environmental Quality (TCEQ), and FLM representatives verbally approved the approach in 2006 and in email exchange with TCEQ representatives in February 2007 (see email from Erik Snyder (EPA) to Greg Nudd of TCEQ Feb. 13, 2007 and response email from Greg Nudd to Erik Snyder Feb. 15, 2007, available in the docket for this action).

[17] See Response to Comments in Appendix A of the 2017 Louisiana Regional Haze SIP submittal.

[18] Maximum impact is defined as the maximum or1st high out of all modeled days (365 days in 2002).

C. Reliance on CSAPR To Satisfy NO_X BART

Louisiana's February 2017 SIP revision relies on CSAPR as a BART alternative for NO_X for EGUs. In our previous proposed approval of this February 2017 SIP revision,[19] we proposed to find that the NO_X BART requirements for all EGUs in Louisiana, including Nelson, will be satisfied by our determination and proposed for separate finalization that Louisiana's participation in CSAPR's ozone-season NO_X program is a permissible alternative to source-specific NO_X BART.[20] We cannot finalize this portion of that proposed SIP approval action unless and until we finalize our separate proposed finding that CSAPR continues to provide for greater reasonable progress than BART[21] because finalization of that proposal provides the basis for Louisiana to rely on CSAPR participation as an alternative to source-specific EGU BART for NO_X. If for some reason our proposed approval of LDEQ's reliance on CSAPR as a BART alternative cannot be finalized, source-by-source BART analyses for NO_X will be required for all subject-to-BART EGUs in Louisiana, including Nelson.

D. Louisiana's Five-Factor Analyses for SO_2 and PM BART for Nelson

In determining BART, the state must consider the five statutory factors in section 169A of the CAA: (1) The costs of compliance; (2) the energy and non-air 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). All units that are subject to BART must undergo a BART analysis. The BART Guidelines break the analysis down into five steps:[22]

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.

As mentioned previously, we disapproved portions of Louisiana's 2008 Regional Haze SIP due to the State's reliance on CAIR as an alternative to source-by-source BART for EGUs.[23] Following our limited disapproval, LDEQ worked closely with Louisiana's BART eligible EGUs, including Nelson, and with us to revise its Regional Haze SIP, which resulted in the submittal of its February and June 2017 SIP revisions addressing BART for Nelson. Although the February 2017 SIP revision addressed Nelson, we did not propose to take action on the SO_2 and PM BART for Nelson in our May 19, 2017 proposed approval.[24] Louisiana's February 2017 SIP revision relies on CSAPR participation as an alternative to source-specific EGU BART for NO_X. The June 2017 SIP revision includes additional information that the State used to evaluate BART for the Nelson facility. Nelson has three BART-eligible steam generating units: Unit 4, Unit 4 Auxiliary Boiler, and Unit 6.

Unit 4 is permitted to combust natural gas, No. 2, No. 4 and No. 6 fuel oils, and refinery fuel gas. Unit 4 has a maximum heat-rated capacity of 5,400 MMBtu/hour and exhausts out of one stack. It has flue gas recirculation equipment installed for control of NO_X emissions. The Unit 4 Auxiliary Boiler is permitted to burn natural gas and fuel oil.

Unit 6 burns coal as its primary fuel and No. 2 and No. 4 fuel oils as secondary fuels. Unit 6 has a maximum heat-rated capacity of 6,216 MMBtu/hour and exhausts out of one stack. It has an electrostatic precipitator (ESP) with flue gas conditioning for control of PM emissions. Unit 6 has installed Separated Overfire Air Technology (SOFA) and a Low NO_X Concentric Firing System (LNCFS) for NO_X control. Entergy submitted a BART screening analysis to us and the LDEQ on August 31, 2015, and a BART five-factor analysis dated November 9, 2015, revised April 15, 2016, in response to an information request.[25] These analyses were adopted and incorporated into Louisiana's February 2017 SIP revision (Appendix D). As part of our effort to assist the State, we submitted a draft analysis of Entergy's CALPUFF and CAMx modeling, our own draft CAMx and CALPUFF modeling, and our own draft cost analysis for Nelson to LDEQ. These analyses were adopted and incorporated into Louisiana's June 2017 SIP revision (Appendix F).

Unit 4 and Unit 4 Auxiliary Boiler

These units are currently permitted to burn natural gas and fuel oil. However, Entergy has not burned fuel oil at either unit in several years. Further, Entergy has no current operational plans to burn fuel oil. The LDEQ did not conduct a five-factor BART analysis for these units. The preamble to the BART Guidelines states:[26]

> Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source's impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible. In a scenario, for example, where a source emits thousands of tons of SO_2 but less than one hundred tons of NO_X, the State could easily conclude that requiring expensive controls to reduce NO_X would not be appropriate.

The SO_2 and PM emissions from gas-fired units are inherently low,[27] so the installation of any additional PM or SO_2 controls on this unit would likely achieve very small emissions reductions and have minimal visibility benefits.

To address SO_2 and PM BART for Unit 4 and the Unit 4 Auxiliary boiler, the June 2017 SIP revision precludes fuel-oil combustion at these units. To make the prohibition on fuel-oil usage enforceable, Entergy and the LDEQ intend to enter an Administrative Order on Consent (AOC), included in the June 2017 SIP revision, that establishes the following requirement:

> Before fuel oil firing is allowed to take place at Unit 4, and the auxiliary boiler at the Facility, a revised BART determination must be promulgated for SO_2 and PM for the fuel oil firing scenario through a FIP or an action by the LDEQ as a SIP revision and approved by the EPA such that the action will become federally enforceable.

We propose to approve the AOC as sufficient to meet the SO_2 and PM BART requirements for Unit 4 and the Unit 4 Auxiliary Boiler. If we finalize our

[19] 82 FR 22936.

[20] *Id,* at 22943.

[21] 81 FR 78954.

[22] 70 FR 39103, 39164 (July 6, 2005) [40 CFR 51, App. Y].

[23] 77 FR 33642.

[24] 82 FR 22936.

[25] Letter from Wren Stenger, Director, Multimedia Planning and Permitting Division, EPA Region 6, to Renee Masinter, Entergy Louisiana (May 19, 2015); letter from Wren Stenger to Paul Castanon, Entergy Gulf States (May 19, 2015; and letter from Wren Stenger to Marcus Brown, Entergy New Orleans (May 19, 2015).

[26] 70 FR 39116.

[27] 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.*

approval of the AOC, it will become federally enforceable for purposes of regional haze.

Unit 6

Identification of Controls

In assessing SO_2 BART in the February 2017 SIP revision (Appendix D), Entergy considered the five BART factors. In assessing feasible control technologies and their effectiveness, Entergy considered low-sulfur coal, Dry Sorbent Injection (DSI), an enhanced DSI system, dry scrubbing (spray dry absorption, or SDA), and wet scrubbing (wet flue gas desulfurization, or wet FGD).

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. We agree with the LDEQ that no technical feasibility concerns warrant removing these controls from consideration as potential BART options for Unit 6.

SO_2 scrubbing techniques utilize a large dedicated vessel in which the chemical reaction between the sorbent[28] and SO_2 takes place either completely or in large part. 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 limestone wet FGD and lime SDA. These controls are in wide use and have been retrofitted to a variety of boiler types and plant configurations. We agree with the LDEQ that no technical feasibility concerns warrant removing these controls from consideration as potential BART options for Unit 6.

Utilization of coal with a lower sulfur content will also result in a reduction in SO_2 emissions. Thus, Entergy identified switching to a lower sulfur coal in order to meet an emission limit of 0.6 lb/MMBtu as a potential BART control option. We note that the BART Guidelines do not require states to consider fuel supply changes as a potential control option,[29] but states are free to do so at their discretion.

Control-Effectiveness

Entergy assessed SDA and wet FGD as being capable of achieving SO_2 emission rates of 0.06 lb/MMBtu and 0.04 lb/MMBtu, respectively. As we discuss in the TSD, based on review of IPM documentation, industry publications, and real-world monitoring data, we agree with the LDEQ that 98% control efficiency for wet FGD and 95% control efficiency for SDA are reasonable assumptions and consistent with the emission rates identified by Entergy.

Entergy determined that DSI could achieve an SO_2 emission rate of 0.47 lb/MMBtu when coupled with the existing Unit 6 ESP and that enhanced DSI could achieve an SO_2 emission rate of 0.19 lb/MMBtu when coupled with a new fabric filter. Finally, Entergy determined that switching to a lower sulfur coal could reduce the SO_2 emission rate at Unit 6 to approximately 0.6 lb/MMBtu.

Impact Analysis

Entergy presented cost-effectiveness figures for each control they evaluated. Entergy estimated that the cost-effectiveness of switching to lower sulfur coal (LSC) would be $597/ton of emissions removed, the cost-effectiveness of DSI would be $5,590/ton, the cost-effectiveness of enhanced DSI would be $5,611/ton, the cost-effectiveness of SDA would be $4,536/ton, and the cost-effectiveness of wet FGD would be $4,413/ton. See Appendix D of the February 2017 Louisiana Regional Haze SIP. In general, Entergy's DSI and scrubber cost calculations were based on a propriety database, so we were unable to verify any of the company's costs. We solicit comment with respect to any information that would support or refute the undocumented costs in Entergy's evaluation. We also note that Entergy's control cost estimates included costs not allowed under our Control Cost Manual (*e.g.,* escalation during construction and owner's costs).[30] Entergy also assumed a contingency of 25%, which we note is unusually high. The lack of documentation aside, removing the disallowed costs and adjusting the contingency to a more reasonable value of 10% significantly improves (lower $/ton) Entergy's cost-effectiveness estimates. For instance, assuming the same SO_2 baseline as we used in our analyses,[31] Entergy's SDA cost-effectiveness would improve from a value of $5,094/ton to $4,154/ton.

Regarding the cost to switch to lower sulfur coal, Entergy states that its $597/ton cost-effectiveness value is based on a lower sulfur coal premium of $0.50/ton, but Entergy does not provide any documentation to support this figure. We examined information regarding Entergy's coal purchases for Nelson Unit 6 from the Energy Information Administration. This information indicated that, although there is some variability in the data, the premium Entergy has historically paid for lower sulfur coal has averaged higher than $0.50/ton.[32] We solicit comments on Entergy's $0.50/ton figure.

Because of these issues, we developed our own control cost analyses, which we present in our TSD. Table 1 summarizes the results of our analyses. For our cost-effectiveness calculations, we used a SO_2 baseline constructed from annual SO_2 emissions from the 2012–2016 period.[33] LDEQ incorporated our cost analysis into Appendix F of its June 2017 SIP revision along with Entergy's cost analysis.

TABLE 1—SUMMARY OF EPA'S COST ANALYSIS

Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Total annualized cost	2016 Cost-effectiveness ($/ton)	2016 Incremental cost-effectiveness ($/ton) *
Nelson Unit 6	Low-Sulfur Coal	11.3	1,149	$3,397,281	$2,957	$2,957
	DSI	50	5,082	18,180,195	3,578	3,759

[28] Limestone is the most common sorbent used in wet scrubbing, while lime is the most common sorbent used in dry scrubbing.

[29] 40 CFR part 51, Appendix Y, Section IV.D.1.5, ''STEP 1: How do I identify all available retrofit emission control techniques?''

[30] As noted in our letter to Kelly McQueen of Entergy on March 16, 2016, we requested documentation for the Nelson Unit 6 cost analyses. Entergy replied on April 15, 2016, but did not supply any additional site specific documentation.

[31] Our SO_2 baseline, used in all of our cost-effectiveness calculations (including our adjustment of Entergy's cost analyses), was obtained from eliminating the max and min of the Nelson Unit 6 annual SO_2 emissions from 2012–2016, and averaging the SO_2 emissions from the remaining years.

[32] We calculated a premium of $2.48 based on a review of coal purchase data for 2016 from EIA. See the TSD for additional information.

[33] Our SO_2 baseline, used in all of our cost-effectiveness calculations (including our adjustment of Entergy's cost analyses), was obtained from eliminating the max and min of the Nelson Unit 6 annual SO_2 emissions from 2012–2016, and averaging the SO_2 emissions from the remaining years.

TABLE 1—SUMMARY OF EPA'S COST ANALYSIS—Continued

Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Total annualized cost	2016 Cost-effectiveness ($/ton)	2016 Incremental cost-effectiveness ($/ton) *
	SDA	92.11	9,361	25,332,736	2,706	1,671
	Wet FGD	94.74	9,628	26,409,798	2,743	4,027

* For low-sulfur coal, the incremental $/ton is relative to use of coal typically used by the source in the past. For each remaining control, incremental $/ton is relative to the control in the row above.

In assessing energy impacts, Entergy identified additional power requirements associated with operating DSI, SDA, and wet FGD. Documentation issues aside, these auxiliary-power costs were accounted for in the variable operating costs in the cost evaluation. Entergy did not identify any energy impacts associated with switching to a lower sulfur coal. We agree with LDEQ's identification of the energy impacts associated with each of the control options.

In assessing non-air quality environmental impacts, Entergy noted that DSI, SDA, and wet FGD would add spent reagent to the waste stream generated by the facility. Entergy accounted for these waste-disposal costs in the variable operating costs in the cost evaluation. See our TSD for further information. Entergy did not identify any non-air quality environmental impacts associated with switching to a lower sulfur coal. We agree with LDEQ's identification of the non-air quality environmental impacts associated with each of the control options.

In assessing remaining useful life, Entergy indicated this factor did not impact the evaluation of controls as there is no enforceable commitment in place to retire Unit 6. We agree with LDEQ that Entergy's use of a 30-year equipment life for the DSI, SDA, and wet FGD cost evaluations, which is consistent with the Control Cost Manual, was therefore appropriate.

In assessing visibility impacts, Entergy evaluated the visibility impacts and potential benefits of each control option (See Appendix D for Entergy's visibility BART analysis for Nelson Unit 6). However, Entergy's CALPUFF modeling included errors in its estimates of sulfuric acid and PM emissions.[34] EPA performed CALPUFF modeling to correct for these errors (See CALPUFF Modeling TSD). The LDEQ incorporated our modeling, among other things, into the June 2017 SIP revision (Appendix F) and considered it along with the visibility analysis developed by Entergy. As we discuss above and in the CAMx Modeling TSD, Entergy also provided additional screening modeling results using CAMx to support its conclusion that visibility impacts from Unit 6 are minimal. However, this modeling was not conducted in accordance with the BART Guidelines and does not properly assess maximum baseline impacts, so we consider this CAMx modeling provided by Entergy to be invalid for supporting a determination of minimal visibility impacts. We performed our own CAMx modeling that follows the BART Guidelines and uses appropriate techniques and metrics to provide additional information on visibility impacts and benefits and to address possible concerns with utilizing CALPUFF to assess visibility impacts at Class I areas located farther from the emission sources. The LDEQ also incorporated this information into the June 2017 SIP revision (Appendix F) and considered it along with the visibility analysis developed by Entergy.

EPA's CAMx modeling for Unit 6 directly evaluated the maximum baseline visibility impacts and potential benefits from DSI. In addition to the DSI modeled benefits, visibility benefits for SDA, wet FGD, and low-sulfur coal were estimated based on linear extrapolation for the average across the top ten impacted days using the modeled baseline and DSI visibility impacts, and estimated emission reductions. We note that the baseline emission rate modeled is based on 24-hr actual emissions during the baseline period (2000–2004), while the control scenario emission rates are based on anticipated 30-day emission rates, as noted in the table below. At a maximum heat input of 6,126 MMBtu/hr for the boiler, the baseline short-term emission rate is approximately 1.2 lb/MMBtu for the 2000–2004 baseline. The results of this modeling for the maximum-impact day and the average across the top ten most impacted baseline days are summarized in Table 2. We note that wet FGD is estimated to provide a very small visibility benefit over SDA on average across the top ten most impacted baseline days, so we do not show the results for wet FGD in this table. See the CAMx Modeling TSD for a full description of the modeling and model results.

TABLE 2—SUMMARY OF EPA'S VISIBILITY ANALYSIS (CAMX)

Class I area	Baseline impact [a] (dv) (maximum)	Baseline Impact (dv) (average for top ten impacted days)	Visibility benefit of controls over baseline (dv) maximum impact	Visibility benefit of controls over baseline (dv) average for top ten impacted days		
			DSI [b]	Low-sulfur coal [c]	DSI [d]	SDA [e]
Breton	0.599	0.314	0.250	0.133	0.165	0.266
Caney Creek	2.179	1.302	1.187	0.411	0.511	0.831
Mingo	1.468	0.785	0.370	0.215	0.265	0.430
Upper Buffalo	1.219	0.934	0.374	0.330	0.408	0.663
Hercules-Glade	1.287	0.777	0.473	0.273	0.338	0.548

[34] See the CALPUFF Modeling TSD for discussion of these errors and corrected values.

TABLE 2—SUMMARY OF EPA'S VISIBILITY ANALYSIS (CAMX)—Continued

Class I area	Baseline impact[a] (dv) (maximum)	Baseline Impact (dv) (average for top ten impacted days)	Visibility benefit of controls over baseline (dv) maximum impact	Visibility benefit of controls over baseline (dv) average for top ten impacted days		
			DSI[b]	Low-sulfur coal[c]	DSI[d]	SDA[e]
Wichita Mountains	0.575	0.412	0.287	0.180	0.223	0.360

[a] 2000–2004 baseline.
[b] DSI at 0.47 lb/MMBtu.
[c] Low-Sulfur Coal benefit (at 0.6 lb/MMBtu, estimated based on linear extrapolation of baseline and DSI visibility impacts at each Class I area.
[d] DSI at 0.47 lb/MMBtu.
[e] SDA at 0.06 lb/MMBtu, estimated based on linear extrapolation of baseline and DSI visibility impacts at each Class I area.

Louisiana's SO_2 BART Determination for Nelson Unit 6

The LDEQ weighed the statutory factors, reviewed Entergy's and EPA's information, and concluded that SO_2 BART is an emission limit of 0.6 lbs/MMBtu based on a 30-day rolling average, consistent with the use of lower-sulfur coal. The LDEQ acknowledged that the visibility benefits of SDA and wet FGD are larger than those associated with lower-sulfur coal, but explained that lower-sulfur coal still achieves some visibility benefits and at a lower annual cost. The LDEQ also noted that SDA and wet FGD create additional waste due to spent reagent and have additional power demands to run the equipment.

Louisiana's PM BART Determination for Nelson Unit 6

The LDEQ noted that Nelson Unit 6 is currently equipped with an ESP to control PM emissions, the visibility impacts from PM emissions are small, and that any additional controls beyond the ESP would have minimal visibility benefits and would not be cost-effective. Therefore, the LDEQ determined that PM BART is an emission limit of 317.61 lb/hr, consistent with the use of the existing ESP.

Our Review of Louisiana's BART Determination for Nelson Unit 6

We propose to approve LDEQ's proposed finding in the June 2017 SIP revision that the visibility impacts from Unit 6's PM emissions are so minimal that any additional PM controls would result in very minimal visibility benefits that would not justify the cost of any upgrades and/or operational changes needed to achieve a more stringent emission limit. Unit 6 is currently equipped with an ESP for controlling PM emissions. The PM control efficiency of ESPs varies somewhat with the design of the ESP, the resistivity of the PM, and the maintenance of the ESP. We do not have information on the control efficiency of the ESP in use at Unit 6. However, reported control efficiencies for well-maintained ESPs typically range from greater than 99% to 99.9%.[35] We consider this pertinent in concluding that the potential additional PM control that a baghouse could offer over an ESP would be very minimal and come at a very high cost.[36] Also, our visibility modeling indicates that the impact from Unit 6's baseline PM emissions is very small, so the visibility improvement from replacing the ESP with a baghouse would be only a fraction of that small impact.[37] As discussed above, states can adopt a more streamlined approach to making BART determinations where appropriate. We therefore propose to agree with Louisiana that no additional controls are required to satisfy PM BART. In the June 2017 SIP revision, the LDEQ and Entergy have proposed to enter into an AOC establishing an enforceable limit on PM_{10} consistent with current controls at 317.61 lb/hr on a 30-day rolling basis. We are proposing to approve this AOC if it is finalized without significant changes and included in the final submittal.

We are also proposing to approve the LDEQ's February 2017 SIP revision as revised by the LDEQ's June 2017 SIP revision that addresses BART for the Nelson facility, including the State's proposed finding that lower sulfur coal is the appropriate SO_2 BART control for Unit 6. LDEQ has weighed the statutory factors and after a review of both Entergy's and EPA's information has concluded that BART is the emission limit of 0.6 lbs/MMBtu based on a 30-day rolling average as defined in the AOC. The LDEQ and Entergy have proposed to enter into an AOC establishing an enforceable limit of SO_2 at 0.6 lbs/MMBtu on a 30-day rolling basis. The emission limit will become enforceable upon EPA's final approval of the SIP. We are proposing to approve this AOC if finalized without significant changes and if it is included in the final submittal.

As the energy industry evolves, the LDEQ has committed to continue to work with EGUs throughout Louisiana to evaluate the operation of utilities. As such, the LDEQ will engage in discussions with Entergy about any potential changes in usage or emission rates at the Nelson facility. Any such changes will be considered for reasonable progress for future planning periods as appropriate.

III. Proposed Action

We are proposing to approve the remaining portion of the Louisiana's Regional Haze SIP revision submitted on February 10, 2017, related to the Entergy Nelson facility and the SIP revision submitted to the EPA for parallel processing on June 20, 2017 that establishes BART for the Nelson facility. We propose to approve the BART determination for Nelson Units 6 and 4 and Unit 4 auxiliary boiler, and the AOC that makes emission limits that represent BART permanent and enforceable for the purposes of regional haze. We solicit comment with respect to any information that would support or refute the undocumented costs in Entergy's evaluation for SO_2 controls on Unit 6. Once we take final action on our proposed approval of Louisiana's 2016 SIP revision addressing non-EGU

[35] 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.

[36] 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.

[37] See the TSD for additional information.

BART,[38] our proposed approval addressing BART for all other BART-eligible EGUs [39] and this proposal to address SO_2 and PM BART for the Nelson facility, we will have fulfilled all outstanding obligations with respect to the Louisiana regional haze program for the first planning period.

The EPA has made the preliminary determination that the June 2017 SIP revision requested by the State to be parallel processed is in accordance with the CAA and consistent with the CAA and the EPA's policy and guidance. Therefore, the EPA is proposing action on the June 2017 SIP revision in parallel with the State's rulemaking process. After the State completes its rulemaking process, adopts its final regulations, and submits these final adopted regulations as a revision to the Louisiana SIP, the EPA will prepare a final action. If changes are made to the State's proposed rule after the EPA's notice of proposed rulemaking, such changes must be acknowledged in the EPA's final rulemaking action. If the changes are significant, then the EPA may be obligated to withdraw our initial proposed action and re-propose.

IV. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, the EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely proposes to approve state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a "significant regulatory action" subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because this action does not involve technical standards; and
- Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the proposed rule does not have tribal implications and will not impose substantial direct costs on tribal governments or preempt tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

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.

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

Dated: June 23, 2017.

Samuel Coleman,

Acting Regional Administrator, Region 6.

[FR Doc. 2017–14693 Filed 7–12–17; 8:45 am]

BILLING CODE 6560–50–P

[38] 81 FR 74750 (October 27, 2016).

[39] 82 FR 22936 (May 19, 2017).

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 62

[EPA–R02–OAR–2017–0132, FRL–9962–42–Region 2]

Approval and Promulgation of Plans for Designated Facilities; New Jersey; Delegation of Authority

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to approve a request from the New Jersey Department of Environmental Protection (NJDEP) for delegation of authority to implement and enforce the Federal plan for Sewage Sludge Incineration (SSI) units. On April 29, 2016 the EPA promulgated the Federal plan for SSI units to fulfill the requirements of sections 111(d)/129 of the Clean Air Act. The Federal plan addresses the implementation and enforcement of the emission guidelines applicable to existing SSI units located in areas not covered by an approved and currently effective state plan. The Federal plan imposes emission limits and other control requirements for existing affected SSI facilities which will reduce designated pollutants.

On January 24, 2017, the NJDEP signed a Memorandum of Agreement which is intended to be the mechanism for the transfer of authority between the EPA and the NJDEP and defines the policies, responsibilities and procedures pursuant to the Federal plan for existing SSI units.

DATES: Written comments must be received on or before August 14, 2017.

ADDRESSES: Submit your comments, identified by Docket ID Number EPA–R02–OAR–2017–0132 at *http://www.regulations.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, 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.*

FOR FURTHER INFORMATION CONTACT: Anthony (Ted) Gardella, Environmental Protection Agency, 290 Broadway, New York, New York 10007–1866, at (212)